SINCLAIR KNIGHT MERZ

SKM

Mt Piper Power Station Extension Environmental Assessment

GREENHOUSE GAS ASSESSMENT

- 20 September 2009

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Abbreviations

AGO	Australian Greenhouse Office
CCGT	Combined Cycle Gas Turbine
CH_4	Methane
CO_2	Carbon Dioxide
DCC	Department of Climate Change
DECC	Department of Environment and Climate Change
Delta	Delta Electricity
GES	Generator Efficiency Standards
GHG	Greenhouse Gases
GWPs	Global Warming Potentials
HFC	Hydrofluorocarbons
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
MW	Meggawatt
MWh	Meggawatt Hour
N_2O	Nitrous Oxide
NEM	National Energy Market
NGA	National Greenhouse Accounts
NGAC	NSW Greenhouse Abatement Certificate
NO_X	Total Oxides of Nitrogen
PFC	Perfluorocarbons
PFBC	Pressurised Fluidised Bed Combustion
SCGT	Simple Cycle Gas Turbine
SF_6	Sulfur Hexafluoride
SKM	Sinclair Knight Merz
UNFCCC	United Nations Framework Convention on Climate Change

1. Introduction

1.1. General Introduction

Delta Electricity (Delta) has commissioned Sinclair Knight Merz (SKM) to undertake an Environmental Assessment for the proposed extension of the Mt Piper Power Station.

While the Mt Piper Power Station site was originally designed as a four unit site, only two units were constructed, with commissioning undertaken in 1992 and 1993. Both units currently operate at a 700MW capacity. Due to forecasted future shortfalls in electricity generation capacity, Delta proposes to increase the generation capacity and electricity production at Mt Piper through the construction of an extension to the existing coal-fired power station.

1.2. Description of the Proposed Development

Delta is considering two options for the extension of the Mt Piper facility and these have been briefly discussed in the following sections.

1.2.1. Option 1 – 2 x 1000MW Coal Fired Power Generators

Option 1 comprises an additional two power generators and associated coal storage and handling facilities.

Connell Wagner undertook a Plant Definition Study (CW, 2008) that defined plant and layout requirements for the extension, comprising 2 x 1000MW ultra-supercritical[1] coal-fired units. The proposed Mt Piper extension would have main and reheat steam temperatures of 600 and 620°C respectively, and a main steam pressure of 28.5MPa, with dry cooling provided by air cooled condensers (ACCs). A single reheat design was chosen due to its commercial predominance and proven design for large ultra-supercritical units.

1.2.2. Option 2 – 6 x 400MW Combined Cycle Gas Turbines

Option 2 would consist of up to six combined cycle gas turbines (CCGT) with a total net capacity of nominally 2,000MW. The new units would employ combined cycle gas turbine technology as this is the most efficient power generation cycle commercially available for this size of plant. As with the coal fired option, ACCs would be used to condense the steam leaving the steam turbines to minimise water usage.

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[1] The term ultra-supercritical is generally adopted for plants that operate with steam conditions above 26MPa and 580°C.

The proposed works would be located generally to the west of the existing power station on the site originally designated in the design and earthworks for the installation of coal fired generation Units 3 and 4.

1.3. Study Objectives

The main objective of this report is to prepare a greenhouse gas (GHG) assessment for the project consistent with the Director General (DG) requirements for the project issued on 19 June 2009.

The DG requirements as relevant to GHGs are as follows:

- ***Greenhouse Gases –*** *the Environmental Assessment must include a comprehensive greenhouse gas assessment undertaken in accordance with the methodology specified in the National Greenhouse Accounts (NGA) Factors (Department of Climate Change, November 2008) including:*
    - *quantification of emissions (in tonnes of carbon dioxide equivalent) in accordance with the Greenhouse Gas Protocol: Corporate Standard (World Council for Sustainable Business Development & World resources Institute) including direct emissions (Scope 1), Indirect emissions from electricity (Scope 2) and any significant up or down stream emissions (Scope 3) considering all stages of the project (construction, operation and decommissioning);*
    - *comparison of predicted emissions intensity and thermal efficiency against: best achievable practice and current NSW averages for the activity, and of predicted emissions against total annual national emissions (expressed as a percentage of the total national greenhouse gases produced per year over the life of the project);*
    - *evaluation of the availability and feasibility of measures to reduce and/ or offset the greenhouse emissions of the project including options for carbon capture and storage. Where current available mitigation technology is not technically or economically feasible, the Environmental Assessment must demonstrate that the proposal will use best available technology, including carbon capture readiness, and identify options for triggers that would require staged implementation of emerging mitigation technologies;*
    - *evaluation of the project in the light of carbon emission prices of $10, $25 and $50 per tonne under the proposed Commonwealth Carbon Pollution Reduction Scheme, both with and without proposed mitigation measures.*

2. Greenhouse Gas Issues

2.1. Overview

This section provides an overview of GHG issues and their relationship to climate change. The major GHGs are also described.

2.2. Greenhouse Gases

GHGs are gases found in the atmosphere that absorb outgoing heat that is reflected from the sun. The absorption of the heat energy warms the air, enabling life to survive, and is known as the Greenhouse Effect. The primary anthropogenic greenhouse gas is carbon dioxide (CO_2).

Human activities, such as the combustion of carbon-based fuels, increase the amount of GHGs in the atmosphere. This leads to greater absorption of heat and increases in atmospheric temperature, known as the Enhanced Greenhouse Effect. The atmospheric concentration of CO_2 has risen from 280 parts per million (ppm) to 370ppm since 1860. At the same time, the average global temperature has increased by nearly 1°C. Projections show that if this trend continues, global temperatures could rise between one and four degrees by the end of the 21st century, with annual average temperatures in Australia projected to increase by 0.4 - 2.0°C by 2030 and by 1 – 6°C by 2070 compared to 1990 levels (WBCSD, 2004).

2.3. Climate Change

Climate change is widely recognised as a major global issue, with human activity and the combustion of fossil fuels increasing the levels of GHGs such as CO_2 in the atmosphere. The build-up of GHGs in the atmosphere may lead to long-term changes in water availability, rising sea levels and changes in weather patterns, causing more extreme events such as droughts, floods and cyclones.

Australia's per capita GHG emissions are among the highest in the world, being more than four times the world average, and are primarily the result of our reliance on coal-generated electricity (Garnaut, 2008). Overall, total net GHG emissions in Australia increased by 4.2% between 1990 and 2006. Energy sector emissions increased by approximately 40% over the same period, and contributed around 70% of Australia's total GHG emissions in 2006. Without mitigation, Australia's GHG emissions would be expected to quadruple by 2100 (Garnaut, 2008).

2.4. Global Warming Potential

Global warming potentials (GWPs) are used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWPs are based on the radiative efficiency (heat-absorbing ability) of each gas relative to that of CO_2, as well as the decay rate of each gas (the amount removed from the atmosphere over a given number of years) relative to that of CO_2. The GWP provides a means to convert emissions of various gases into a common measure, which is denoted in carbon dioxide equivalents (CO_2-e).

The generally-accepted authority on GWPs is the Intergovernmental Panel on Climate Change (IPCC). The IPCC regularly updates its estimates of GWPs for key greenhouse gases. **Table 2-1** compares the GWPs published by the IPCC in 1996, 2001 and 2006. It should be noted, however, that reporting under the Kyoto Protocol is based on the 1996 IPCC GWPs.

- **Table 2-1 Comparison of 100-Year GWP Estimates**

Greenhouse Gas	1996 IPCC GWP	2001 IPCC GWP	2006 IPCC GWP
Carbon Dioxide	1	1	1
Methane	21	23	25
Nitrous Oxide	310	296	298
HFC-23	11,700	12,000	14,800
HFC-125	2,800	3,400	3,500
HFC-134a	1,300	1,300	1,430
HFC-143a	3,800	4,300	4,470
HFC-152a	140	120	124
HFC-227ea	2,900	3,500	3,220
HFC-236fa	6,300	9,400	9,810
Perfluoromethane (CF_4)	6,500	5,700	7,390
Perfluoroethane (C_2F_6)	9,200	11,900	12,200
Sulphur Hexafluoride (SF_6)	23,900	22,200	22,800

Sources: IPCC's Second (1996), Third (2001) and Fourth (2006) Assessment Reports

As shown above, the latest GWP for CH_4 is 25, and for N_2O is 298. This means that emissions of 1 tonne of CH_4 and N_2O are respectively equivalent to emissions of 25 and 298 tonnes of CO_2 (tCO_2-e).

2.5. Major Greenhouse Gases

A brief discussion on each of the following major GHGs produced or influenced by human activities is presented in the following sections:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Synthetic halocarbons
- Sulfur hexafluoride (SF_6)

- Other important gases

2.5.1. Carbon Dioxide

Carbon dioxide is the main anthropogenic gas contributing to climate change, responsible for approximately 63% of the warming associated with climate change. Concentrations of this gas in the atmosphere have increased by approximately 36% during the past 200 years, from 280ppm in the 1700s to 370ppm in 2005, with concentrations increasing at a progressively faster rate each decade - the average growth rate of CO_2 emissions increased from 1.1% per year in the 1990s to a 3% increase per year in the 2000s (Raupach et al., 2007). The major anthropogenic sources of CO_2 emissions are fossil fuel combustion and land clearing for agriculture.

2.5.2. Methane

Atmospheric methane concentrations have increased by 150% during the past 200 years. While atmospheric methane concentrations remained relatively constant over the past decade, recent monitoring results from CSIRO and others indicate that concentrations showed renewed growth from the beginning of 2007 (Rigby et al., 2008), possibly caused by increases in emissions in the Northern Hemisphere.

Although there is a lower proportion of methane in the atmosphere than carbon dioxide, methane has a significantly higher GWP (refer to **Table 2-1**). The major sources of methane are cattle, rice growing and leakages during natural gas production, distribution and use. While natural processes currently remove methane from the atmosphere at almost the same rate as it is being added, methane concentrations are likely to rise over the next 100 years.

2.5.3. Nitrous Oxide

Atmospheric nitrous oxide concentrations have increased by 15% during the past 200 years and the gas can persist in the atmosphere for up to 100 years. Major sources of nitrous oxide include industrial processes, fertiliser use and other agricultural activities, including land clearing.

2.5.4. Halocarbons

Halocarbons are chemicals that contain carbon atoms linked with one or more halogen atoms (fluorine, chlorine, bromine or iodine). Chlorofluorocarbons (CFCs) are a type of halocarbon, and formerly had widespread use as refrigerants before they were found to deplete ozone levels in the upper atmosphere. Hydrofluorocarbons (HFCs) were introduced to replace CFCs in the refrigerant industry since they do not deplete ozone as they contain no chlorine. HFCs, however, can have GWPs more than 11,000 times that of CO_2, and are targeted under the Kyoto Protocol (refer to **Section 3.2.1**), together with another class of halocarbon, perfluorocarbons (PFCs).

As technologies currently exist to reduce emissions of these gases to near zero over the next few decades, they represent probably the most significant, immediate opportunity to slow down the current growth of GHGs in the atmosphere.

2.5.5. Sulfur Hexafluoride

Sulfur hexafluoride (SF_6) is a synthetic gas. The Australian Standard (AS2791-1996) for the use and handling of SF_6 in high voltage switchgear and control gear states that SF_6 gas has no odour, smell or taste, and is non-combustible and chemically inert at room temperature.

The Greenhouse Challenge Discussion Paper *Sulfur Hexafluoride and the Electricity Supply Industry*, issued by the Australian Greenhouse Office in 2001, details that SF_6 emissions can occur from its use in metal processing and the electricity supply industry. While the quantities of emissions of this gas are currently comparatively small to those generated during the combustion of fossil fuels, its GWP is 23,900 times that of carbon dioxide.

The main use of SF_6 globally is in electricity transmission and distribution, which accounts for approximately 80 per cent of use. These industries use SF_6 for electrical insulation, arc quenching, and current interruption in equipment used in the transmission and distribution of electricity. Most of the SF_6used in the electrical equipment is used in gas insulated switchgear (GIS) and circuit breakers, although some SF_6 is used in high voltage gas-insulated transmission lines and other equipment. International data suggested that handling losses results in 80 to 85% of all SF_6 emissions from the electricity supply industry, with leakages from equipment representing between 15 and 20% of emissions.

Delta manages SF_6 through well-documented company guidelines that conform to AS 2791-1996 requirements.

2.5.6. Other Important Gases

The hydroxyl radical (OH) is a highly reactive agent that helps to cleanse the atmosphere of pollutants such as methane. OH will also react with carbon monoxide which, although not a GHG, reduces the amount of OH in the atmosphere, thereby increasing the length of time GHGs such as methane stay in the atmosphere. Carbon monoxide, hydrocarbons and oxides of nitrogen can react to form ozone, another GHG. In contrast to ozone depletion in the stratosphere, ozone in the troposphere acts as an effective GHG.

3. Greenhouse Gas Response

3.1. Overview

This section summarises and provides information based on the Australian Government's commitment to GHG management as detailed in National and International policy, and also provides a summary of Australia's latest National Greenhouse Gas Inventory Report (2006).

3.2. International Response

The international response to climate change has involved the development of an international treaty designed to limit the emissions of GHG and ozone depleting substances: the *Kyoto Protocol to the Framework Convention on Climate*.

3.2.1. The Kyoto Protocol

The objective of the Kyoto Protocol is to reduce the GHG emissions worldwide. The Kyoto Protocol establishes provisions to limit emissions of specified greenhouse gases (GHGs) (UNEP, 1997). Signatories to the *Kyoto Protocol* would be required to reduce GHG emissions by at least 5% below 1990 levels by 2008 - 2012 (DEC, 2003).

It is understood that some countries will do better than expected in reducing GHG emissions, coming in under 5%, while others will exceed 5%. This means that some countries that have emissions units to spare (that is, emissions permitted to them but not used). The Protocol allows countries to sell their excess emission units to other countries so that countries not meeting their commitments will be able to buy compliance. This gives rise to a carbon market.

The Kyoto Protocol sets a framework for the control of the emission of six greenhouse gases (GHGs). These gases are:

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

On 3 December 2007, the Australian Prime Minister, Kevin Rudd, signed the instrument of ratification of the Kyoto Protocol. As such, Australia has committed to meeting its Kyoto Protocol target, and has set a target to reduce greenhouse gas emissions by 60% on 2000 levels by 2050.

3.3. National Response

3.3.1. The Department of Climate Change (DCC)

The Commonwealth Department of Climate Change (DCC, formerly the Australian Greenhouse Office or AGO) was established on 3 December 2007 as part of the Prime Minister and Cabinet Portfolio. It followed the establishment of the Australian Greenhouse Office (AGO), part of the Department of the Environment and Heritage, to coordinate national climate change policy and drive associated programs such as the National Greenhouse Strategy (AGO, 2004).

The National Greenhouse Strategy was developed to provide the strategic framework for an effective greenhouse response and for meeting current and future international commitments. The Strategy was endorsed by the Commonwealth and all State and Territory governments in 1998. The three goals of the National Greenhouse Strategy are to:

1) Limit net GHG emissions, in particular to meet our international commitments;
2) Foster knowledge and understanding of greenhouse issues; and
3) Lay the foundations for adaptation to climate change.

Australia has developed methodologies consistent with the Intergovernmental Panel on Climate Change (IPCC) guidelines for preparing and reporting the National Greenhouse Gas Inventory (NGGIC, 1996).

The DCC delivers the majority of programs under the Australian Government’s $1.8 billion climate change strategy. This strategy is centred on five key areas including emissions management, international engagement, strategic policy support, impacts and adaptation, and science and measurement. Major initiatives include:

- Boosting renewable energy actions and pursuing greater energy efficiency;
- Investing significant resources into greenhouse research and monitoring Australia's progress towards its Kyoto target through the National Greenhouse Gas Inventory;
- Studying the landscape of Australia through the National Carbon Accounting System;
- Encouraging the development and commercialisation of low emissions technologies;
- Encouraging industry, business and the community to use less greenhouse intensive transport; and
- Fostering sustainable land management practices.

3.3.2. Generator Efficiency Standards

Generator Efficiency Standards (GES) are one of the key energy measures announced in the Prime Minister's 1997 climate change statement, *Safeguarding the Future: Australia's Response to*

Climate Change. The objectives of the measure are to encourage fossil-fuelled electricity generation to move towards best practice and to reduce the GHG intensity of energy supply. The Standards were endorsed by the Council of Australian Governments in 1998 and subsequently incorporated into the National Greenhouse Strategy.

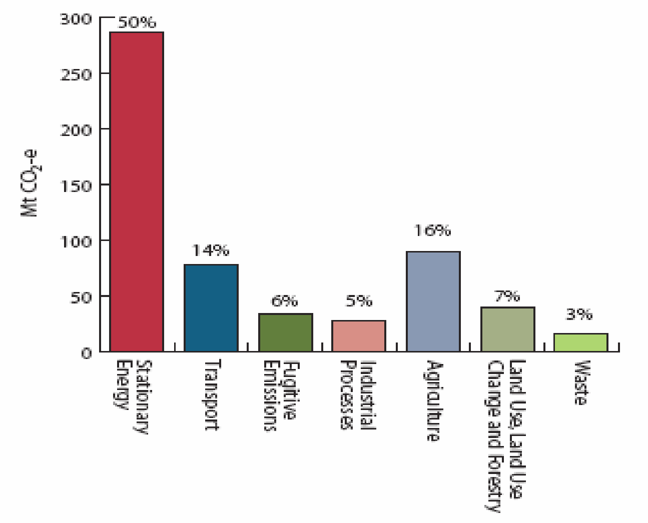
These guidelines were developed following extensive consultation with industry, electricity users and the wider community, and were publicly released in July 2000. The GES measure applies to all fossil-fuelled power generation plants with an electrical capacity of 30MW or more and with an annual electrical output of 50GWh per year. The Australian Government enters into legally binding Deeds of Agreement with businesses affected by the GES through the Greenhouse Challenge Plus program.

3.3.3. National Greenhouse Gas Inventory

Australia’s *National Greenhouse Gas Inventory 2006* (DCC, 2008c) has the dual purpose of providing estimates of Australia’s net greenhouse gas emissions and of tracking Australia’s progress towards its internationally-agreed target of limiting emissions to 108% of 1990 levels over the period 2008–2012. Australia has updated and published annual national greenhouse gas inventories for each year from 1990 to 2006 inclusive. The inventories are prepared according to international guidelines established by the IPCC and Kyoto accounting provisions.

In 2006, Australia’s net greenhouse gas emissions using the Kyoto accounting provisions were 576.0Mt of CO_2-e. The energy sector was the largest source of greenhouse gas emissions, accounting for 69.6% (400.9Mt CO_2-e) of emissions in 2006, followed by agriculture (15.6%) and land use, land use change and forestry sectors (6.9%). The industrial processes contributed 4.9% and the waste sectors contributed 2.9% (refer to **Figure 3-1** and **Table 3-1** below).

Figure 3-1: Australia's Estimated GHG Emissions by Sector for 2006



Source: AGO, 2008

Table 3-1 Australian Net Greenhouse Gas Emissions by Sector for 2006

Sector and Subsector	Emissions (Mt)				
	CO_2	CH_4	N_2O	HCFCs/ PFCs SF_6	CO_2-e
All energy (combustion + fugitive)	367.8	30.4	2.7	NA	400.9
Stationary energy	285.3	1.1	1.0	NA	287.4
Transport	76.8	0.6	1.7	NA	79.1
Fugitive emissions from fuel	5.8	28.7	0.02	NA	34.5
Industrial processes	22.6	0.1	0.02	5.8	28.4
Agriculture	NA	69.8	20.3	NA	90.1
Land use, land use change and forestry	37.4	2.1	0.6	NA	40.0
Waste	0.03	16.0	0.6	NA	16.6
Total Net Emissions	427.8	118.3	24.2	NA	576.0

Notes:
NA = not applicable
Source: National Greenhouse Gas Inventory 2006 (DCC, 2008c:4)

3.3.4. Greenhouse Gas Reporting

The *National Greenhouse and Energy Reporting Act 2007* (the Act) was passed on 29 September 2007, establishing a mandatory reporting system for corporate GHG emissions and energy production and consumption in Australia. The first reporting period under the Act commenced on 1 July 2008. Information obtained from the reporting process is intended to be used for the development of the Carbon Pollution Reduction Scheme (refer to **Section 3.3.6**).

The National Greenhouse and Energy Reporting (NGER) Guidelines were developed to help corporations understand their obligations under the Act. The Reporting Guidelines are applicable across industry sectors and cover important concepts under the Act and the *National Greenhouse and Energy Reporting Regulations 2008* (the Regulation), including determining the need to report, how to register, reporting obligations, and record keeping requirements. The Reporting Guidelines were designed for use with the NGER Technical Guidelines.

The NGER Technical Guidelines (DCC, 2008b) were developed to assist stakeholders understand and apply the NGER (Measurement) Determination 2008, which outlines calculation methods and criteria for GHG emissions, energy production and consumption. The methods are based on those used for the National Greenhouse Accounts. The range of emission sources covered in the Technical Guidelines and Determination include:

- The combustion of fuels for energy;
- Fugitive emissions from the extraction of coal;
- Oil and gas;
- Industrial processes (such as producing cement and steel); and
- Waste management.

Reporting thresholds for the first tier of participation are facilities with emissions of 25,000 t CO_2-e or that consume or produce 100TJ, or corporations with 125,000 t CO_2-e or 500TJ.

3.3.5. The Garnaut Climate Change Review

In 2007, the Commonwealth, state and territory governments commissioned the Garnaut Climate Change Review, an independent report to investigate the likely effects of climate change on Australia's economy, environment and water resources. The Review also provided recommendations on medium- to long-term policy options to produce the best possible outcomes for Australia.

The Review stressed the importance of a global effort to reduce CO_2 emissions. Recommendations were made for Australia to support the objective of working towards holding concentrations of atmospheric CO_2 to 450ppm and to indicate its willingness to reduce its own emissions by 25% of 2000 levels by 2020 and by 90% by 2050 in the context of a global agreement. The Review determined that it will be difficult to obtain international agreement on this target, and that making a commitment to such sizeable reductions could potentially have large financial effects on Australian industries if other countries do not agree to similar actions. Commitment to a 550ppm target was considered to be more achievable internationally; as such, the Review recommended that Australia commit to an unconditional 5% reduction in emissions from 2000 levels by 2020 in the absence of an international agreement.

The Review also provide guidance for the design of an emissions trading scheme, which was considered to be the best method of reducing GHG emissions for Australia if properly designed and implemented. Recommendations for administration of the Scheme by an independent authority and pricing and trajectories of emissions targets were also made, and the Review stressed that all emission permits should be sold competitively on a periodic basis to deliver the required emission reduction trajectories.

The Review indicated that the trading scheme should be established as early as possible, that is, by 2010. The revenue generated from the sale of carbon permits would be allocated as: payments to households (approximately 50%); support for research, development and commercialisation of new technologies (around 20%); or to business as either credits for trade-exposed activities or as tax reductions (approximately 30%).

3.3.6. National Carbon Pollution Reduction Scheme

The *White Paper – Carbon Pollution Reduction Scheme* was released on 15 December 2008. The Paper sets out the Government's policy in relation to two major elements of its mitigation strategy - a medium-term target range for national emissions, and the final design of the Carbon Pollution Reduction Scheme (CPRS). The White Paper (policy position) builds on the earlier Green Paper (options and consultation), and the recommendations of the Garnaut Review.

The Scheme will be Australia's primary policy tool to drive reductions in emissions of greenhouse gases. The economic cost of GHG emissions is not currently reflected in the costs of business or the price of goods and services as firms currently face no cost from increasing emissions. The CPRS is designed to redress this market failure through a cap-and-trade system to reduce carbon pollution.

The White Paper sets a GHG emissions target for Australia of a 5% reduction on 2000 emission levels by 2020, which will increase to 15% if similar commitments are made by other major international emitters. Initial targets will be confirmed in early 2010 following negotiations at the international climate conference in Copenhagen in 2009. The Scheme maintains a long-term target of a 60% reduction in GHG emissions by 2050.

Carbon prices are initially expected to be around $25/ tonne. A price cap of $40 /tonne will be enforced for the first 5 years of the scheme, increasing by 5% per year. Permits will be auctioned monthly and will be able to be purchased up to four years in advance; deferred payment for future-dated permits may be possible.

The CPRS provides assistance for industries likely to be strongly affected by the Scheme (that is, those that are emissions intensive). Electricity generators with a carbon intensity of more than

0.86 tCO_2-e/MWh will receive a one-off allocation of permits. Additionally, a national energy efficiency strategy is to be developed and implemented in 2009.

The Scheme will cover the major GHG emitters - approximately 1,000 entities that together account for around 75% of Australia's emissions from the stationary energy, transport, fugitive, industrial processes, waste and forestry sectors by each emitting more than 25,000 tCO_2-e per year. The Scheme will cover all six greenhouse gases covered under the Kyoto Protocol (CO_2, CH_4, N_2O, SF_6, HFCs and PFCs).

The CPRS is designed to limit carbon pollution while minimising the impact on business and households. There are two distinct elements - the cap on carbon pollution and the ability to trade. The cap achieves the environmental outcome of reducing carbon pollution. The ability to trade ensures carbon pollution is reduced at the lowest possible cost.

The mechanics of a cap and trade Carbon Pollution Reduction Scheme are described below:

- The Government sets a cap on the total amount of carbon pollution allowed in the economy by covered sectors.
- The Government will issue permits up to the annual cap each year.
- Industries that generate carbon pollution will need to acquire a permit for every tonne of greenhouse gas that they emit.
- The quantity of carbon pollution produced by each firm will be monitored and verified
- At the end of each year, each liable firm would need to surrender a permit for every tonne of carbon pollution the firm produced in that year.
- Firms compete in the market to purchase the number of permits that they require. Firms that value the permits most highly will be prepared to pay the most for them, either at auction, or on a secondary trading market. For some firms, it will be cheaper to reduce emissions than to buy permits.
- As a transitional assistance measure, certain categories of firms might receive some emissions permits for free. These firms could use these permits or sell them.

The price of permits is not set by the Government, rather emerges from the market. If a firm can reduce carbon pollution more cheaply than the prevailing market price of permits, it will choose to reduce carbon pollution rather than buy permits. This kind of scheme provides a strong incentive for participants to reduce their own carbon pollution. By making this business decision around whether to reduce carbon pollution or trade in permits, firms operate within the overall cap at least cost.

In this way, the CPRS gives firms the flexibility to choose the most cost-effective way to meet the carbon pollution cap. At the same time, the carbon pollution market provides a greater financial incentive for firms to develop and adopt technologies to reduce emissions (further information is available at www.climatechange.gov.au).

The timetable for implementation of the CPRS is outlined below:

- March – June 2008: Phase 1 consultation with stakeholders to inform development of the Green Paper.
- July 2008: Public release of the Green Paper on the design of the CPRS.
- July – September 2008: Phase 2 consultation (Green Paper).
- December 2008: Public release of the White Paper, outlining the scheme design and its planned medium-term trajectory.
- February 2009: public release of exposure draft legislation.
- March – April 2009: Phase 3 consultation (exposure draft legislation).
- May 2009: Bill introduced into Parliament.

3.3.7. Energy White Paper

In 2008, the Australian Government agreed to the development of a White Paper on energy issues, which is to be a key priority for the Energy and Resources portfolio. The purpose of the Paper is to ensure the provision of clean, adequate, reliable and affordable energy supplies to meet Australia’s growing energy needs. This goal is considered to be integral to the country’s economic prosperity, and will ensure Australia reduces its fossil fuel-related GHG emissions.

The White Paper will provide a comprehensive policy framework through to 2030, which will address both energy security and climate change issues. The Energy White Paper will also provide short- to medium-term recommendations for government and industry, focusing on investment and employment in the resources and energy sectors[2].

3.4. State Response

3.4.1. NSW Greenhouse Gas Reduction Scheme (GGAS)

The NSW Greenhouse Gas Reduction Scheme (GGAS) commenced on 1 January 2003. It was one of the first mandatory greenhouse gas emissions trading schemes in the world. GGAS aims to

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[2] http://www.ret.gov.au/energy/facts/Pages/EnergyFacts.aspx

reduce greenhouse gas emissions associated with the production and use of electricity. It achieves this by using project-based activities to offset the production of greenhouse gas emissions.

GGAS establishes annual statewide greenhouse gas reduction targets, and then requires individual electricity retailers and certain other parties who buy or sell electricity in NSW to meet mandatory benchmarks based on the size of their share of the electricity market. If these parties, known as benchmark participants, fail to meet their benchmarks, then a penalty is assigned. Monitoring the performance of benchmark participants is undertaken by the Independent Pricing and Regulatory Tribunal of NSW (IPART) in its role as Compliance Regulator.

Assessing abatement projects, accrediting parties to undertake eligible projects and then create certificates, and monitoring compliance with GGAS is the responsibility of the Scheme Administrator, currently IPART. The Scheme Administrator also manages the Greenhouse Registry which records the registration and transfer of certificates created from abatement projects.

3.4.2. NSW Government Energy Directions Green Paper

The level of maximum electricity demand in NSW is increasing at a rate of around 4% per year. While there is currently sufficient electricity generation capacity in NSW to meet demand, additional generation capacity will be required in the near future.

As the development of additional capacity requires significant lead times for appropriate planning, financing and construction of new energy assets, the purpose of the Energy Directions Green Paper (2004) was to provide regulatory certainty for investors. Additionally, the Green Paper outlines options for reform in terms of GHG emissions, regulated pricing and the structure of Government-owned energy businesses.

The increase in electricity demand has led to additional consequences, including an increase in GHG emissions from electricity production by almost 50% between 1994 and 2004. In an attempt to curb these emissions, the NSW Government placed mandatory GHG reduction targets on its electricity retailers under the Greenhouse Gas Reduction Scheme (formerly the Greenhouse Gas Abatement Scheme or GGAS, which required electricity retailers to progressively reduce their GHG emissions to 95% of 1990 per capita levels by 2007). Currently, the Greenhouse Gas Reduction Scheme (known as the NSW Benchmark Scheme), which commenced in 2003, is a GHG trading scheme that imposes annual GHG emission targets on electricity retailers and large electricity users. These targets are currently set until the end of 2012.

The NSW GGAS benchmark for 2012 of 7.27 t CO_2-e per capita implies an average net emission intensity of around 0.7 t CO_2-e/MWh (medium demand growth and including credits for demand-side and non-electricity abatement). The Green Paper considered that it would be appropriate for NSW to require new generators to operate to minimum emission performance standards, that is, be no worse than the average emission intensity implied by the benchmark. Any proposed technology that could meet or achieve the standard would be, in theory, acceptable.

Under the Green Paper, all new power stations, including gas-fired stations, are expected to adopt best available technology to minimise pollutant emissions. To avoid land use conflicts, the paper also recommended that plants should be located in industrial areas or so as to avoid visually prominent locations.

3.4.3. NSW Government's Inquiry to Electricity Supply in NSW

The NSW Government's (Owen) *Inquiry into Electricity Supply in NSW* (September 2007) established the need for additional base load electricity in NSW by the summer of 2013/14.

The Inquiry identified alternative technologies for base load electricity generation, which can be categorised as follows:

- Advanced Coal and Gas Technologies:
  - Integrated Coal Gasification Combined Cycle (IGCC);
  - Ultra Clean Coal Combined Cycle (UCC); and
- Renewable Energy Technologies:
  - Hydro;
  - Wind;
  - Solid biomass;
  - Solar thermal; and
  - Geothermal hot dry rock.

While nuclear technology is a mature energy-generating technology with low carbon emissions, the Inquiry ruled out nuclear generation as an alternative base load option on the basis of NSW Government policy and the absence of a nuclear energy regulatory framework in NSW.

Alternative technologies not suitable for base load generation were also identified. In NSW, these technologies included ocean wave, ocean tidal, solar photo-voltaic, geothermal aquifer, biomass gasification, biogas methane, fluidised bed coal combustion, and pressurised fluidised bed coal combustion.

The Inquiry concluded that "*the most technologically advanced, commercially viable options currently available for the next tranche of base load generation in NSW are CCGT and Ultra-supercritical Coal (USC)*". It should be noted, however, that a report to the Owen Inquiry by Connell Wagner (Connell Wagner, 2007) indicated that carbon capture and storage for CCGT would not be commercially available until 2020.

3.5. Delta Electricity Initiatives

Delta Electricity is a State-owned corporation that is committed to improving the energy efficiency and potential greenhouse impact of its operations. Delta recognises the growing concerns of global warming and the emissions of GHGs, from the combustion of fossil fuels. Delta monitors the quantity of CO_2 emissions and thermal efficiencies at all of their power stations, including Mt Piper. Programs have also been implemented to improve operational performance and reduce CO_2 emissions. These programs include:

- Renewable Energy: Development of renewable generation sources;
- Greenhouse Challenge: Delta has been a member of the Greenhouse Challenge Program since 1997; and
- Generator Efficiency Standard: Delta was the first generator to agree to legally binding targets under the Australian Government's Generator Efficiency Standards. The objectives of the Generator Efficiency Standards measure are to:
    - achieve movement towards best practice in the efficiency of fossil-fuelled electricity generation; and
    - deliver reductions in the GHG intensity of energy supply.

As a signatory to the Commonwealth Government's Generator Efficiency Standards (GES), Delta is required to implement actions to bring their power stations within the best practice efficiency bands, and if already within the bands, to take actions to further improve efficiency. The first phase of this program ended in 2005. In 2003/04, all Delta power stations were within the best practice bands and close to the lower bound (best efficiency) level (Delta 2004). As such, Delta undertook additional actions to contribute to energy efficiency and/or GHG reductions, including:

- Complying with the NSW Government Energy Management Policy, which aims to reduce energy use in government operations;
- Trialling electric/petrol hybrid cars to reduce fuel consumption in Delta's car fleet;
- Investigating the possible use of GHG-neutral biodiesel as a replacement for fuel oil used in boiler start-ups;
- Being a member of COAL21, a research program that focuses on breakthrough technologies for coal-fired power generation, that is , those with the potential to deliver radical reductions or even eliminate emissions; and
- Being a member of Bioenergy Australia and currently the Australian task leader of the International Energy Agency co-firing task.

3.5.1. Delta Electricity's Greenhouse Gas Emissions

Delta collects environmental data and reports environmental performance via indicators that conform to the Environmental Performance Indicator Guidelines for the Australian Electricity Industry (2003). These guidelines were produced by the Energy Supply Association of Australia as part of an eco-efficiency agreement with Environment Australia.

Total GHG emissions for the existing Mt Piper power station (Delta Electricity Sustainability Report, 2007) are shown in **Table 3-2**.

- **Table 3-2 Mt Piper Power Station Greenhouse Gas Emissions for 2007**

Emission	Tonnes CO_2-e	t CO_2-e /GWh
GHG Emissions	7,916,193	849

Delta worked with CSIRO to develop, install and implement a carbon capture plant at its Munmorah Power Station, which began operation in 2008. A demonstration-scale plant is planned for 2012 and, if successful, the technology may be retrofitted to existing coal-fired plant or incorporated into new plants.

3.5.2. Research into New Power Generation Options

Delta is evaluating long-term options for future power generation. Options include using low emission technologies, such as high efficiency coal and gas-fired plant. Part of this process involves Delta being a member of COAL21. COAL21 is a research program that focuses on breakthrough technologies for coal-fired power generation, that is, those technologies with the potential to deliver radical reductions or even eliminate emissions.

3.5.3. Renewable Energy Development

Delta's sustainable development strategy includes producing renewable energy from using sugar cane waste as fuel, co-firing biomass with coal and hydro-electric generation.

Cogeneration

Delta in a joint venture with the NSW Sugar Milling Cooperative developed two new 30MW renewable energy plants at Condong and Broadwater sugar mills on the NSW North Coast that commenced commercial operation in late 2008. The cogeneration units produce steam for the mills and green energy for use in the region from waste materials generated from milling sugar cane. The project is the largest renewable base load energy project in NSW, and supplies the equivalent of 60,000 homes, reducing around 400,000 tonnes of GHG emissions each year. Additionally, use of the waste for power generation will result in the gradual phasing out of burning sugar cane in the fields before harvesting, reducing air pollution in the local communities.

Biomass Co-firing

Delta aims to reduce GHG emissions from their coal-fired power stations by up to 20,000 tonnes each year by co-firing renewable biomass fuels with coal. The biomass fuel includes sawdust from radiata plantation sawmills and unusable construction and demolition timber. Co-firing wood waste not only reduces the amount of coal burnt, but also prevents the wood from breaking down, a process that produces methane. Biomass co-firing routinely occurs at Delta's power stations at Vales Point, Wallerawang and Mt Piper. In support of this program, Delta is a member of Bioenergy Australia and is currently the Australian task leader of the International Energy Agency co-firing task.

Hydro-electric Generation

Delta has mini hydro-electricity plants at Mt Piper, Chichester Dam and the Dungog Water Treatment Plant, which are operated by Hunter Water. Two additional plants are under development at Windamere Dam and Glennies Creek Dam. Electricity produced from these plants is recognised as renewable energy under various government schemes.

Gas Fired Generation

Additionally, Delta has invested in a number of gas turbines at Colongra (construction well advanced), Bamarang (development approval granted) and Marulan (currently being assessed by the Department of Planning), for a combined capacity of 1467MW, primarily for peaking operation.

3.5.4. Energy Efficiency and Conservation

A fundamental driver for profitability is the efficiency in conversion of coal to electricity. Delta has an Efficiency Committee of technical experts whose role is to monitor the performance of all power stations to ensure that each plant maintains its best possible operational efficiency. The Committee reports issues of significance to the Executive Environment Committee to ensure a high-level focus is maintained on production efficiency. A key driver in this process is the ability of stations to generate additional NGAC (NSW Greenhouse Abatement Certificate) income under the NSW Greenhouse Gas Benchmark scheme. This is possible when a station's efficiency exceeds the best practice efficiency line defined in the Commonwealth Government GES. To ensure a continued focus on this, the production of NGACs has been incorporated into the company's Balanced Scorecard, an incentive scheme that rewards staff on the basis of business unit performance.

4. Project Greenhouse Gas Emissions

4.1. Overview

This section estimates the GHG emissions associated with each proposed power station extension configured as either as an ultra-supercritical (USC) coal fired plant or a combined cycle gas turbine (CCGT) plant.

4.2. GHG Emissions Estimation Methodology

As specified by the DG requirements, quantification of GHG emissions is in accordance with GHG Protocol: Corporate Standard (World Business Council for Sustainable Development and World Resource Institute) including direct emissions (Scope 1), indirect emissions from electricity (Scope 2) and any significant up or downstream emissions (Scope 3) considering all stages of the project (construction, operation and decommissioning).

The *GHG Protocol Corporate Standard* (the Protocol) provides standards and methodologies for organisations preparing GHG emissions inventories. It presents methods for accounting and reporting the six greenhouse gases covered by the Kyoto Protocol (that is, CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6).

The *GHG Protocol Corporate Standard* and accompanying guidance were designed with the following objectives in mind:

- To assist companies in preparing an accurate GHG inventory, through the use of standardised methods and principles;
- To simplify and reduce the costs of compiling a GHG inventory;
- To provide business with information to assist with designing effective strategies to manage and reduce GHG emissions;
- To assist businesses to participate in voluntary and mandatory GHG programs; and
- To increase consistency and transparency in GHG accounting and reporting across different companies and GHG programs.

Table 4-1 sets out the proposed assessment methodology which has been developed in accordance with the GHG Protocol.

- **Table 4-1 GHG Assessment Methodology**

Element	Description
Project Boundaries	▪ The project boundary will include the expanded power station asset ▪ The project boundary includes construction, operational and decommissioning phase emissions. ▪ Direct emissions from combustion of fuel (Scope 1), indirect emissions from consumption of electricity (Scope 2) and, as relevant to construction, other upstream and downstream indirect emissions (Scope 3) are included in the assessment. ▪ In terms of Scope 3 emissions associated with construction, operation and decommissioning these occur from upstream and downstream processes and include: **Construction:** - Embodied energy of construction materials - Transport of materials and waste to and from construction sites - Disposal of waste to landfill **Operation:** - Fuel (coal or gas) extraction GHG emission - Emissions from delivery of fuel to site **Decommissioning:** - Transport of materials and waste away from the decommissioning site - Disposal of waste to landfill
Calculating GHG Emissions	▪ The assessment methodology should be based on accurate estimates of activity data, fuel consumption and material quantities ▪ GHG emission factors should be those provided by the DCC – National Greenhouse Accounts (NGA) November 2008 Factors ▪ In terms of assessing the range of GHG emission sources to be considered for the assessment a test of significance should be applied and in general where individual emissions sources are assessed to make up less than 1 % of the emissions when compared to the largest emission source during either the construction or operational phase of the project these emissions would be considered insignificant and need not be included in the assessment.
Assessment of GHG Management Measures	▪ Refer to Section 5 to follow

4.3. Benchmarking Efficiency and GHG Emissions

The NSW Greenhouse Gas Abatement Scheme (GGAS) estimated NSW pool coefficient for 2009 is 0.967tCO_2-e/MWh. Applying the GGAS emissions calculation methodology to Mt Piper Extension gives an emissions intensity of 0.838tCO_2-e/MWh (including coal mine fugitive emissions), well below the current estimated pool coefficient.

Under the Australian Generator Efficiency Standards, the AGO specifies indicative values reflecting Best Available Technology (BAT) power plant efficiency and greenhouse intensity for new plant (AGO, 2006). The standards for ultra-supercritical coal-fired plant using dry cooling and fuelled by black coal are shown in Table 4-2 , which compares these standards to the estimates by

Connell Wagner, now Aurecon (2008, 2009), for the Mt Piper Extension specified at 25°C and 60% relative humidity.

In the preparation of these Best Available Technology efficiency tables in the GES Technical Guidelines 2006 it would appear that a very simplified approach has been taken. The GES design efficiency implies an auxiliary load of approximately 5% which would seem very low for a dry cooled plant as 8% would be more typical. Also the GES table makes no mention of the losses associated with the steam piping, which are separate from the losses associated with the boiler and turbine. The GES design boiler efficiency of 89.4% is also considered high for plant equipped with low NO_X burners. It is also noted that a 12kPa pressure has been assumed for the condenser whereas, based on recent information from equipment suppliers, commercial plant has a limit of 15kPa for air cooled condensers.

The aspect of Best Practice developed by the AGO in the original GES Technical Guidelines 2001 recognised that the different commercial conditions in Australia, eg, low coal costs, meant that the ‘best commercial practice’ for Australia would be different from that of best achievable practice. Where the proposed station efficiency fell short of the best achievable practice the AGO required that a case be put to them justifying the best commercial efficiency for Australian conditions. It is unclear what is the status of this requirements once the CPRS is introduced.

The comparison of the GES efficiency to the proposed Mt Piper extension at 25°C does not represent a reasonable basis as the annual average ambient temperature for Mt Piper is approximately 13°C. The annual average net sent out efficiency for the proposed Mt Piper Extension is 39.2%, equivalent to 813kgCO_2/MWh based on NGA Factors.

It is also noted that the GES efficiency is based on an altitude of 111m compared to Mt Piper at 940m. This variation equates to an efficiency differential of the order of 0.1%.

The proposed Mt Piper extension is considered to be best commercial available technology as follows:

- Steam conditions of 28.5MPa and 600°C with 620°C will be close to the maximum conditions of any commercial plant operating or planed for the near future, worldwide (refer **Appendix A**);
- Dry cooling technology is used to minimise water usage;
- The dry air cooled condenser pressure of 15kPa represents the lowest known in commercial operation for large SC plant.

- **Table 4-2 Emissions Intensities calculated according to AGO Generator Efficiency Standards for Ultra-supercritical Plant with Dry Cooling**

Coal	**GES Black Coal 2**	**Mt Piper Extension**
CO_2 emission factor(kg CO_2/GJ fuel)	90.1 [1]	89.2 [2]
Ambient and steam conditions		
Dry bulb temperature (^oC)	25	25
Relative humidity (%)	60	60
Main (superheat) steam at turbine inlet		
Pressure (MPa)	27.5	28.5
Temperature (^oC)	605	600
Reheat (single) steam at turbine inlet		
Pressure (MPa)	5.7	5.9
Temperature (^oC)	613	620
Final feedwater temperature (^oC)	290	303
Unit performance		
Gross power (MWe)	429	1000
Net power (MWe)	410	923.7
Sent-out power (MWe)	408	919.4
Boiler efficiency (%, HHV)	89.4	89.1
Turbine efficiency (%)	46.6	-
Sent-out thermal efficiency (%, HHV)	39.7	39.2
Power station CO_2 emission (kg/MWh SO)	820	834

Source: Table F9, AGO (2006); Connell Wagner (2008)
1. Medium ash, low - medium volatile domestic coal (e.g. Hunter Valley coal)
2. Cobbora coal

4.4. Project GHG Emission Estimates

As per the DG requirements the projects Scope 1, 2 and 3 GHG emissions have been estimated using GHG Protocol and NGA methodologies.

4.4.1. Scope 1 Emissions - Power Station

This section outlines direct GHG emissions from both USC coal and CCGT plant.

Emissions from 2 x 1000MW Ultra Super Critical (USC) Coal Plant

The study defined the plant requirements based on the installation of two 1000 MW ultra-supercritical coal-fired units with dry cooling and the following ratings at design conditions:

- 1000MW gross output at generator terminals with 8.06% auxiliary power usage;
- Turbine inlet steam at 600^{o}C (main)/ 620^{o}C (reheat)/ 28.5MPa (main steam pressure);

- Air cooled condenser with 29^{o}C Inlet Temperature Differential and 15kPa turbine back pressure; and
- Unit sent out efficiency of 38.6% at 25^{o}C and 60% relative humidity.

The turbine inlet steam conditions above are the normal conditions for international commercially-available high temperature alloys. A single reheat design was chosen because this is the commercially predominant and proven design for large ultra-supercritical units (Connell Wagner, 2008).

The NGA Factors (DCC, 2008a) provide the following equation and emission factors to calculate GHG emissions from the combustion of coal or gas for the proposed power station.

$$\mathbf{E_{ij} = (Q_i \times EC_i \times EF_{ijoxec})/1000}$$

Where:

E_{ij} = Emissions of gas type (j), CO_2, CH_4 or N_2O, from fuel type (i) (CO_2-e tonnes).
Q_i = The quantity of fuel type (i) (tonnes).
EC_i = The energy content factor of fuel type (GJ/t). If Qi is measured in GJ then ECi is 1.
EF_{ijoxec} = Emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kg CO_2-e /GJ)

The fuel combustion emission factor for black coal used for electricity generation is 88.43kgCO_2-e/GJ (Table 1, NGA Factors, 2008).

Table 4-3 compares the estimated GHG emissions per year associated with the proposed ultra-supercritical technology to those associated with alternative fossil fuel technologies. The emissions intensity has been determined as an annual average for a plant operating at a capacity factor of 80% (sourced from Connell Wagner Plant Definition Study, 2008) by adjusting the design efficiency for variation in ambient conditions.

- **Table 4-3 Fossil Fuel Alternative Technologies comparison CO_2-e emissions calculated based on NGA Factors**

	Units	CCGT	Ultra-supercritical
Nominal size [1]	[MW]	2000	2 x 1000
Fuel	-	Natural Gas	Black Coal
Emissions factor	[kg CO_2-e/GJ]	51.33	88.43
Generation sent out	[MWh]	13,722,000	12,886,000
Emissions Intensity	[t CO_2-e/MWh]	0.358	0.813
CO_2-e Emissions	[Mt/year]	4.91	10.47
Emissions compared to stationary emissions (Energy Sector)	[%]	1.71	3.65
Emissions compared to total energy sector	[%]	1.22	2.61

1. Nominal gross capacity for comparison purposes - actual capacity for CCGT plant will vary depending on GT chosen.

Using this method, around 10.47Mt CO_2-e per year would be produced from the proposed coal fired plant at 80% capacity factor.

As outlined in **Table 3-1**, the net GHG emissions (CO_2-e) for stationary sources from the energy sector in 2006 was 287Mt and for the total energy sector was 401Mt. The estimated GHG emissions from the combustion of fuel by the proposed Mt Piper extension equate to less than 4% of the CO_2 emissions calculated in 2006 for stationary sources and the total energy sector.

Emissions from 6 x 400MW Combined Cycle Gas Turbine (CCGT) Plant

The simplest configuration consists of a gas turbine (GT), a heat recovery steam generator (HRSG) and a condensing steam turbine (ST).

Natural gas is fired in the gas turbine which drives a generator producing power. The hot exhaust gases from the gas turbine are ducted into the heat recovery steam generator to produce steam (replacing the conventional fossil fuel fired boiler). The steam is expanded through the steam turbine driving a generator to produce additional power.

Approximately two thirds of the cycle power is generated by the gas turbine and the remaining one third by the steam turbine. This ratio varies slightly, however, with plant selection and the mode of operation. Typical installed efficiencies range between 50 to 55% (HHV) at standard design conditions. The simple combined cycle configuration above is described as 1 x 1 x 1, that is, there is one GT, one HRSG and one ST which would generate around 400MW. Other configurations are possible, the most common alternative being 2 x 2 x 1 which would generate around 800MW.

The fuel combustion emission factor for natural gas is 51.33kgCO_2-e/GJ (Table 2, NGA Factors, 2008).

Table 4-4 shows the estimated GHG emissions per year associated with the proposed CCGT plant. The emissions intensity has been determined as an annual average for a plant operating at a capacity factor of 80% by adjusting the design efficiency for variation in ambient conditions and part load operation.

- **Table 4-4 Combined cycle gas turbine CO_2-e emissions calculated based on NGA Factors**

	Units	Combined Cycle Gas Turbine
Net output [1]	[MW]	2295
Fuel	-	Natural Gas
Emission factor	[kgCO_2-e/GJ]	51.33
Generation sent out	[MWh]	16,083,000
Emissions intensity	[tCO_2-e/MWh]	0.358
CO_2-e emissions	[Mt/year]	5.76
Emissions compared to stationary emissions (Energy Sector)	[%]	2.01
Emissions compared to total energy sector	[%]	1.44

1. Based on 6 x GE 9FB GTs in combined cycle with dry cooling.

4.4.2. Scope 2 Emissions – Electricity Consumption

Scope 2 GHG emissions from the consumption of purchased electricity will be negligible as electricity consumed at the power station site will be generated on-site.

4.4.3. Scope 3 Emissions – Upstream and Downstream Processes

Construction

GHG emissions associated with power station construction have been estimated using published information of major construction materials (steel and concrete) for other power station projects.

GHGs from Embodied Energy of Construction Materials

It is assumed that the majority of construction materials would comprise of concrete and steel. A desktop search for relevant quantities of concrete and steel was conducted for both gas and coal fired power plants. Estimated quantities of construction material and Scope 3 embodied emissions associated with the manufacturing of raw materials for Option 1- USC and Option 2 - CCGT are presented in **Table 4-5** and **Table 4-6** respectively.

Table 4-5 Steel and Concrete Quantities and Embodied Energy for Option 1 - USC

Construction Material / Embodied Emission	Plant Component	Quantity	Total GHGs (t CO_2-e)
Steel 2.65 t CO_2-e per tonne	Power Station	45,700 tonnes	121,105
	Air Cooled Condenser	3,100 tonnes	8,215
	Total	**48,800 tonnes**	**129,320**
Concrete Density = 2.16 t/m^3 0.126 t CO_2-e per tonne	Stack	11,200 m^3	3,048
	Foundation	10,200m^3	2,776
	Total	**21,400 m^3**	**5,824**
TOTAL			**135,144**

Table 4-6 Steel and Concrete Quantities and Embodied Energy for Option 2 - CCGT

Construction Material / Embodied Emission	Plant Component	Quantity	Total GHGs (t CO_2-e)
Steel 2.65 tC O_2-e per tonne	HRSG	1,000 tonnes	2,650
	Gas Turbines	4,200 tonnes	11,130
	Steam Turbine	2,500 tonnes	6,625
	Stacks	1,400 tonnes	3,710
	Air Cooled Condenser	3,100 tonnes	8,215
	Total	**12,200 tonnes**	**32,330**
Concrete Density = 2.16 t/m^3 0.126 tCO_2-e per tonne	Foundations	10,200 m^3	2,776
	Total	**10,200m^3**	**2,776**
TOTAL			**35,106**

The embodied emissions for the coal fired power station was determined to be 129,320 t CO_2-e for steel and 5,824 t CO_2-e for concrete; totalling 135,144 t CO_2-e. Total estimated embodied energy of construction materials required for the proposed gas fired power station are lower at 32,330 t CO_2-e for steel and 2,776 t CO_2-e for concrete; totalling 35,106 t CO_2-e.

Transportation of Materials

Scope 3 emissions resulting from the transport of construction materials to the site including return trips are shown in **Table 4-7** and **Table 4-8** for Option 1 – USC and Option 2 – CCGT respectively.

It is assumed that steel would be sourced from Wollongong, approximately 217km from the study area. The steel would be transported to the site in 20 tonne loads and the fuel efficiency of a semi trailer is approximately 0.546L/km (AGO, 2006).

For the purpose of this assessment concrete would be sourced from Lithgow, approximately 18km from the study area. Concrete would be transported pre-mixed from the cement supplier to the site using a $7m^3$ truck and the fuel efficiency of the cement truck is assumed to be 0.285L/km (AGO, 2006). An emission factor of 2.698 t CO_2-e/kL has been used for transport fuel (diesel) consumption (DCC, 2008a).

- **Table 4-7 Transport of Construction Materials and Waste for USC option**

Activity	Distance per load (km)	Number of trips	Fuel used (diesel, kL)	t CO_2-e
Transport of steel	434	2440	578	1560
Transport of concrete	36	3057	31	84
Total t CO_2-e				**1664**

- **Table 4-8 Transport of Construction Materials and Waste for CCGT option**

Activity	Distance per load (km)	Number of trips	Fuel used (diesel, kL)	t CO_2-e
Transport of steel	434	610	145	391
Transport of concrete	36	1457	15	40
Total t CO_2-e				**431**

Transport and Disposal of Waste to Landfill

Given that the construction site is a Greenfield site, waste generation will be minimal associated energy and GHG emissions from waste will be negligible.

Fuel Supply

Coal Mining and Transport by Rail

Mt Piper Power Station primarily obtains coal from the Lithgow area, from Clarence in the south to Baal Bone in the north. To date, the majority of coal has been sourced from two medium-sized underground longwall mines - the Angus Place Mine and the Springvale Mine - through long term contracts. The balance of the coal is supplied under short-term and annual contracts from a reducing number of underground and open cut mines, utilising mainly public roads for coal delivery.

The current coal supplies have sufficient infrastructure and reserves to supply the existing Mt Piper Power Station into the foreseeable future. The proposed extension would increase the coal usage to around 9Mtpa. Coal for the proposed extension would be sourced from a competitive market, and is likely to come from the Cobbora mine, approximately 200km northwest of Mt Piper. The additional coal (approximately 5.7Mtpa) is likely be supplied by rail, utilising the existing (but incomplete and disused) rail infrastructure.

It has been assumed that the Cobbora mine will be an open-cut operation. The DCC provides a CO_2-e emission factor estimate of 0.045 tonnes CO_2-e/tonne of run-of-mine coal for open-cut mines in NSW (DCC, 2008a), and the following equation is used to determine GHG emissions:

$$E_J = Q \times EF_J$$

where:

E_j = Fugitive emissions of CH_4 (j) that result from the production of coal (t CO_2-e)
Q = The quantity of run-of-mine coal extracted (tonnes)
EF_j = Emission factor for methane (j) (t CO_2-e per tonne of run-of-mine coal)

Based on the above, the additional fugitive emissions from open-cut mining to supply coal to Mt Piper power station are estimated to be 256,500 t CO_2-e [5,700,000 t x 0.045 t CO_2-e/t ROM].

The following equation (DCC, 2008a) was used to calculate GHG emissions based on the fuel consumed during the transport of coal by rail from Cobbora Mine to Mt Piper to cater for the additional 5.7Mt supply of coal each year.

$$E_{ij} = (Q_i \times EC_i \times EF_{ijoxec})/1000$$

where:

E_{ij} = Emissions of gas type (j), CO_2, CH_4 or N_2O, from fuel type (i) (CO_2-e tonnes).
Q_i = The quantity of fuel type (i) (kilolitres) combusted for transport energy processes
EC_j = The energy content factor of fuel type (GJ/kL) used for transport energy purposes
EF_j = Emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kg CO_2-e / GJ) used for transport energy purposes

As shown in **Figure 4-9**, the total CO_2-e emissions from the transportation of coal by rail from Cobbora to Mt Piper was calculated to be 55,601 t (0.056Mt) CO_2-e/year for 2 x 1000MW.

- **Table 4-9 CO_2-e Emissions from Rail Transport of Coal from Cobbora to Mt Piper**

Item		Units	2 x 1000 MW plant
Diesel oil emission factor[1]	CO_2	kg CO_2-e/GJ	69.2
	CH_4		0.2
	N_2O		0.5
Energy content factor[1]		GJ/kL	38.6
Fuel consumption rate[2]		L/h @ 50 km/h	1042
Distance - round trip from Cobbora to Mt Piper		km	400
Average train speed		km/h	50
Number of trains		Per year	2472
Drive time per train		h/round trip	8
Round trip fuel consumption		L/round trip	8336
Annual fuel consumption		kL/year	20,607
CO_2-e Emissions		**t/year**	**55,601**

Note: Based on a 4/82 type train, which has 41 wagons with 75t of coal in each wagon.

1. *Source: Table 4: Fuel combustion emission factors - fuels used for transport energy purposes from the National Greenhouse Accounts (NGA) Factors (DCC, 2008a)*
2. *Fuel Consumption Rate based on - Notch Setting 5/7 Average x 4 locomotives.*

As detailed in **Table 3-1**, the total CO_2-e emissions from transportation in the energy sector was 80.4Mt in 2007. Thus, the total CO_2-e emissions likely from rail transport associated with the proposed Mt Piper Power Station extension is less than 0.07% of total transportation CO_2 emissions in 2007.

Natural Gas Extraction and Supply

The CCGT plant option will require approximately 133PJ per annum of natural gas. This gas will be delivered to Mt Piper via a new gas pipeline.

The DCC provides a CO_2-e emission factor estimate of 15.7kg CO_2-e/GJ as Scope 3 emissions for large users (DCC, 2008a). Therefore, the Scope 3 emissions associated with natural gas extraction and supply are estimated to be 2,088,100 t CO_2-e [133,000,000 GJ x 0.0157 t CO_2-e/GJ].

Transport and Disposal of Ash

In the existing power station, flyash is handled in the fly ash collection plant, boilers, crusher and dewatering screens by conveyors. Under the USC extension option, a new pneumatic extraction and transportation system would extract flyash from the fabric filter hoppers and transport it to a new flyash storage silo. The new flyash silo would provide 3 days storage for the two new units and the silo would be equipped with a truck loading facility to allow truck transport off-site or to the ash disposal areas.

Approximately 20% or 150,000 tonnes per year of flyash from the existing plant is sold to Flyash Australia. This ash is transferred from the existing flyash silo to Flyash Australia's on-site plant.

In addition, there is an ash disposal area for the existing plant located on the north-east side of the site. This area currently receives approximately 600,000m^3 per annum and it is estimated to have approximately 5-6 years capacity, after which an alternative ash disposal area will be required. The options for future ash disposal from the existing plant and ash disposal for the extension project are subject to a separate study and approval process.

In light of the above, purchased electricity for operation of the ash transport and conveyor systems will be negligible as electricity consumed will be generated on-site. The GHGs associated with trucks transporting ash from the site to the disposal area will also be small, relative to the plant operation emissions, due to the small travel distances involved. No estimates of GHGs from the transport and disposal of ash activities have been made.

Decommissioning

In terms of power station decommissioning, actual GHG emissions are difficult to estimate, given the timing of the works and the market for recycled materials in particular steel and crushed concrete products. Typical sources of GHG emissions associated with decommissioning include:

- Fuel use in cranes and other mobile plant used to dismantle the power station;
- Crushing plant used to break up concrete foundations; and
- Fuel use in trucks that are transporting waste materials away from the site, either to land fill or other recycling facilities.

It is expected that at the time of decommissioning the Australian and NSW economy will be carbon constrained and a high priority will be placed on recycling material in particular steel and it is expected that significant proportion of power station materials will be recycled.

4.4.4. Incidental GHG Emissions

There will be other GHG emissions associated with the power station development, however, as they both individually and collectively will make up a very small percentage of total GHG emissions (for example, 0.5% of total emission as defined as "incidental" within the NGERS framework). Some of these emissions sources include:

- Fuel use from the transport of workers and maintenance personnel to and from the site;
- Fuel use from power station deliveries; and
- Embodied emissions from chemicals and other materials associated with power station operations.

4.4.5. Summary of GHG Emissions

Table 4-10 summarises the Scope 1, 2 and 3 GHG emissions associated with the Mt Piper power station extension.

- **Table 4-10 GHG Emissions Summary**

Source	USC (t CO_2-e/y)	CCGT (t CO_2-e/y)
Scope 1		
Operations (fuel combustion)	10,470,000	4,910,000
Scope 2		
Electricity usage	Negligible	Negligible
Scope 3		
Construction (embodied energy of materials)	135,144*	35,106*
Construction (transportation of materials)	1,664*	431*
Transport and disposal of waste to landfill	Negligible	Negligible
Fuel supply (coal mining)	256,500	0
Fuel supply (coal transport by rail)	55,601	0
Fuel supply (natural gas extraction and supply)	0	2,088,100
Transport and disposal of ash	Negligible	0
Decommissioning	Not calculated	Not calculated
Total (Scope 1, Scope 2 and Scope 3)	**10,918,909**	**7,033,637**

- Construction emissions do not recur on an annual basis

5. Greenhouse Gas Management

5.1. Overview

The management of greenhouse gas emissions through reductions or offsets is discussed below. Forms of GHG offsets include:

- Sequestration through carbon sinks;
- Carbon credit trading;
- Geosequestration;
- Renewable energy production.

These offsets are outlined briefly in the following sections.

5.2. Carbon Sink Sequestration

Carbon sinks involve the use of trees and vegetation to compensate for carbon inputs into the atmosphere through the burning of fossil fuels. There are two fundamental approaches to sequestering carbon in terrestrial ecosystems:

- Protection of ecosystems that store carbon so that sequestration can be maintained or increased;
- Enhancement of the ability of ecosystems to increase carbon sequestration beyond current conditions.

The first option would involve purchasing an area of land for protection in the long-term to offset emissions. The latter option is the more frequently employed method and involves tree planting on cleared land. This is typically achieved by expansive plantations of which can be harvested for wood chips to recoup establishment and maintenance costs.

In this instance, however, only permanent afforestation is relevant. If logging were to be permitted, the final destination of the wood need to be accounted for. Most wood uses are counted as returning the embedded carbon to the atmosphere over some non-geological timeframe and could be as little as 50 - 100 years. Consequently, in the case of harvested wood, only the amount of average sequestered carbon that can be accounted for should be considered.

Hence either:

- Land is returned to forest permanently without harvesting; or
- Land is permanently turned to commercial forestry where the trees are harvested by rotation.

In the latter case, the land required for a particular quantum of sequestration is much larger because only the average quantity of carbon present at site over the cycle can be counted as an offset, and because the cycle time tends to be less than that required to grow fully mature trees. Whether the activity makes a net profit or loss on the forestry activity also needs to be evaluated in calculating the cost of sequestration.

Estimations of the ability for vegetation to sequester carbon dioxide vary depending on the photosynthesis rate of the plant/tree and climatic conditions. Accumulation of sequestered carbon in forests tends to be slow in the very early stages of growth, accelerates as trees fully exploit their sites' resources and then decreases again once maturity is reached. If trees grow to an over-mature state, the net rate of sequestration may be negative as biomass decomposition releases carbon faster than it accumulates. The amount of rainfall at a site has a strong influence on growth rates for trees and on the underlying value of the land utilised.

5.3. Renewable Energy Production

Renewable energy is obtained from sources that are essentially inexhaustible. Renewable sources of energy include conventional hydro-electric power, wood, waste, geothermal, wind, solar photovoltaic and solar thermal energy.

For renewable energy production the fundamental assumption is that each MWh of energy generated displaces a MWh that would have come from a fossil fuel generator. The greenhouse offset can, therefore, be calculated using the following equation:

- Tonnes of CO_2-e offset per annum = MWh pa x greenhouse intensity of displaced energy

There may be some debate about the greenhouse intensity figure that should be used in this equation.

Some of the options include:

- The greenhouse intensity of the proponent's generator;
- The greenhouse intensity of the generator on the interconnected system, the output of which would be curtailed to allow the system to accommodate the output of renewable energy; or
- The average greenhouse intensity of the interconnected system.

While it is possible to construct an argument for either of the first two options, in practical operation, the system operator will manage generators to maintain system stability, so renewable technology is unlikely to be associated with any other single generator on the system. Consequently, over the year, the average greenhouse intensity of the interconnected system is the most appropriate figure.

5.4. Carbon Capture and Storage

Carbon Capture and Storage (CCS) is a group of technologies for capturing the CO_2 emitted from power plants and industrial sites, compressing this CO_2 and transporting it to suitable permanent storage sites such as deep geological formations.

All of the currently available technologies for separating a concentrated CO_2 stream from a large power generation plant require both significant additional equipment and a significantly increased input of energy, when compared to ‘conventional’ power generation technologies without CO_2 capture. The form of the additional equipment and the nature of the energy consumption vary, but the outcome is that all plants fitted with CO_2 capture technology produce power which has a higher basic cost (ie before any cost for emitting CO_2 is taken into account) and which is produced at lower efficiency compared to conventional fossil-fired plants without CO_2 capture.

There are three carbon capture processes applicable to power generation plant:

- Pre -Combustion Capture
- Oxyfuel Combustion
- Post-Combustion Capture

For pre-combustion capture the gas fuel is reformed (with steam alone or a steam/O_2 mixture) to give a mixture rich in H_2 and CO_2. In systems with solid or liquid fuels, these are gasified (with air, O_2 and/or steam) to give a synthesis gas 'syngas' which is shifted to again give a gas rich in CO_2 and H_2. The CO_2 is then separated from the H_2, typically using a physical or mixed solvent system or membranes. The CO_2 is then dried, compressed and sent for storage, whilst the hydrogen-rich gas passes to a gas turbine or fuel cell to generate power.

The Oxyfuel combustion technology involves replacement of combustion air with a mixture of CO_2 rich flue gas recycle and oxygen for combustion. An air separation unit is required to supply a stream of near pure oxygen into the flue gas recycle for the combustion process. A major part of flue gas has to be recycled back to the boiler plant. The resulting flue gas from an Oxyfuel boiler is predominantly CO_2 and water. The CO_2 rich flue gas needs to be cleaned and dried prior to compression for storage.

The most widely considered technology for post-combustion capture involves the use of chemical solvents – typically a form of amine - which react with the CO_2 in the flue gas from a normal combustion process and is subsequently regenerated at a higher temperature, producing a purified CO_2 stream suitable for compression and storage. Other capture technologies, based on flue-gas refrigeration or the use of other capture solvents such as chilled aqueous ammonia are also under development. For amine-based systems, the flue gas needs to be pre-treated to reduce acid gas

(NO_2 and SO_2) concentrations to extremely low levels to prevent these reacting irreversibly with the solvents, then cooled either in a heat exchanger or by direct contact with the amine in a scrubber column. The CO_2 -rich solvent is then passed to a stripping column where it is heated in a reboiler to drive off the CO_2 and the amine is recirculated.

For the proposed extension of Mt Piper Power Station only Post-Combustion Capture technology is applicable. Although Post-Combustion Capture technology is commercially proven at industrial scale, its integration with coal fired power plant, CO_2 transport and geological storage is in the early stages of development.

It is expected that the cost of Post-Combustion Capture technology is expected to reduce quite markedly as it becomes more widely deployed at large scale. This was the case for power station flue gas sulphur scrubbing technology, where capital costs halved when the technology was developed at scale and in numbers.

While carbon capture and storage is a promising large scale emission abatement technology, it is in the early stages of development and is not commercially feasible for inclusion in the Mt Piper Extension at this time. It is proposed to prepare the power station to be capable of accepting carbon capture technology when it is commercially feasible.

5.4.1. Carbon Capture Ready

There is currently no agreed international or Australian definition for “Carbon Capture Ready” although there are number of draft definitions under consideration. The International Energy Agency (IEA, 2007) has proposed a definition which is widely referenced in relation to requirements for carbon capture readiness and is considered the best available guide.

The IEA summarises capture ready power plant considerations as follows:

A CO_2 capture ready power plant is a plant which can include CO_2 capture when the necessary regulatory or economic drivers are in place. The aim of building plants that are capture ready is to reduce the risk of stranded assets and ‘carbon lock in’.

Developers of capture ready plants should take responsibility for ensuring that all known factors in their control that would prevent installation and operation of CO_2 capture have been identified and eliminated.

This might include:

1. *A study of options for CO_2 capture retrofit and potential pre-investments*
2. *Inclusion of sufficient space and access for the additional facilities that would be required*

3. Identification of reasonable routes (s) to storage of CO_2.

These requirements are addressed below.

1. A study of options for CO_2 capture retrofit and potential pre-investments

Capture technologies are developing rapidly and there is a possibility that configuring a power plant design for equipment currently available may lock in obsolescence, as technologies available in the medium term may be significantly different. For this reason it is recommended a detailed study of capture retrofit options be deferred and undertaken as late in the power station final design stage as possible.

The study of retrofit options at the design stage would aim to identify factors that may prevent a retrofit of capture technology taking place and ensure they are addressed in the design. As a minimum this would involve review of provision for space to accommodate additional steam ducting, provision to expand the plant control system and ability to expand the auxiliary plant electrical distribution system.

Importantly, installation of high efficiency power generation technology will minimise the quantity of carbon dioxide which will need to be captured.

Delta Electricity is assessing technologies for post combustion capture in conjunction with CSIRO at its Munmorah Pilot Plant. Delta is also planning to demonstrate an integrated carbon capture, transport and storage technology at an industrial scale of 100,000 tonne per year at one of its Central Coast power stations. Subject to the availability of grant funding and final storage characterisation this is expected to be operational in 2014. This project will provide the foundations for utility scale commercial CCS in NSW.

2. Inclusion of sufficient space and access for the additional facilities that would be required

The project site layout has allocated sufficient space to accommodate installation of future carbon capture technologies, as shown in Chapter 3 of the EA.

3. Identification of reasonable routes to storage of CO_2

The NSW generators and Department of Industry and Investment have undertaken studies to assess the carbon dioxide storage potential in NSW sedimentary basins. These findings of the studies indicate the likelihood of large scale storage potential in the Darling Basin, which would need to be confirmed by exploratory drilling and seismic survey.

NSW Department of Industry and Investment has commenced an exploratory drilling program in NSW which aims to characterise the storage potential of the Darling Basin as well as assessing closer options in the Sydney and Gunnedah Basins.

Stage 1 of the Regional Stratigraphic Drilling Program commenced in January 2009 to locate and investigate potential permeable reservoirs, primarily sandstone beds, within the Sydney-Gunnedah Basin sequence that may be suitable for the geosequestration of CO_2. This stage of the drilling project includes drilling and analysis of four wells in the Sydney and Gunnedah Basins.

The first well was drilled at Munmorah power station and completed in June 2009. Drilling at a second well is underway nearby at Vales Point Power Station, with data and recommendations from both wells expected to be available in December 2009. Depending on the results of Stage 1 work further wells may be drilled in the Sydney Basin.

Stage 2 is a broader state wide regional assessment of large scale storage potential focussing on the Darling and Clarence-Moreton Basins.

The drilling program will provide information that will allow more accurate modelling and prediction of reservoir characteristics in the Sydney and Gunnedah Basins.

The design and operation of pipelines for transport of carbon dioxide is well understood. Transportation of CO_2 over long distances through pipelines has been undertaken for more than 30 years in the US and Canada for enhanced oil recovery.

An assessment of pipeline transport to the Darling basin has also been completed by the NSW generators, including identification of a potential transport route from the Hunter Valley. Western region power stations would be connected by following exiting rail easements to meet the Hunter Valley pipeline route south of Dunedoo. This preliminary study considered the most direct route while avoiding townships and areas of high terrain. It also assessed the need for power sources and booster compressor stations. Although the route identified by the study is reasonable the final route selection will be subject to the outcome of the exploratory drilling program, and may be significantly shorter if large scale storage is available in the Gunnedah basin.

5.4.2. Capture Technology Costs and Implementation Triggers

Initially CCS costs are expected to be of the order of €60-90/tCO_2 (McKinsey, 2008) or approximately AUD100-150/tCO_2, though decreasing as the technology develops. Therefore CCS technology is not currently economically feasible.

The trigger point for the implementation of carbon capture and storage will be when the technology is technically proven and the cost of implementing CCS reduces to less than the cost of carbon emissions under an operating carbon trading scheme.

Although CCS technology is not currently economically feasible, a key element of managing CO_2 emissions would be the implementation of a process to periodically review technologies and their viability in order to appropriately plan for their eventual implementation at the proposed Mt Piper Power Station Extension. This review process would incorporate potential trigger points for implementation of CCS.

The Proponent would undertake a review at a minimum of every two years in order to monitor and keep up to date with CCS technologies that are available or in development. This review would also include monitoring the availability of technologies and opportunities to transport and store captured CO_2. The results of each review would be detailed in a report to be made available to the NSW Department of Planning.

The review process would include assessment of available technologies at that point in time for carbon capture, transport and storage, with the following considerations:

- if the technology has been technically proven and tested, in that there is an appropriate level of confidence that the plant is practically feasible, operable from an engineering perspective and would deliver the desired outcomes;
- if the technology is scalable and able to be retrofitted to the proposed extension of Mt Piper Power Station;
- the operational viability of each element of the technology in conjunction with other elements (ie CO_2 capture along with CO_2 transport and storage);
- if all relevant environmental risks of the CCS technology have been minimised (eg the potential for CO_2 leakage from storage sites).

The achievement of the above considerations would then be a trigger point for more detailed assessment of the available CCS technology, including:

- if the technology is commercially viable and has appropriate costs compared to benefits, including in relation to the presence or absence of a formal carbon trading scheme, such as CPRS, if applicable and the broader financial implications for the Proponent.
- if there are other significant constraints or opportunities related to the implementation of CCS.

When a review process successfully passes all of the above considerations, this would be a trigger point for the preparation of a detailed CCS implementation plan, which would be prepared in consultation with the relevant regulatory authority.

6. Implications of the Carbon Pollution Reduction Scheme

6.1. Overview

As discussed in **Section 3.3.6**, the CPRS is designed to limit carbon pollution while minimising the impact on business and households. The CPRS is designed to redress this market failure through a cap-and-trade system to reduce carbon pollution.

The price of permits is not set by the Government, rather it emerges from the market. If a firm can reduce carbon pollution more cheaply than the prevailing market price of permits, it will choose to reduce carbon pollution rather than buy permits. This kind of scheme provides a strong incentive for participants to reduce their own carbon pollution. By making this business decision around whether to reduce carbon pollution or trade in permits, firms operate within the overall cap at least-cost.

Carbon prices are initially expected to be around $25/tonne. A price cap of $40/tonne will be enforced for the first 5 years of the scheme, increasing by 5% per year. Permits will be auctioned monthly and will be able to be purchased up to four years in advance; deferred payment for future-dated permits may be possible.

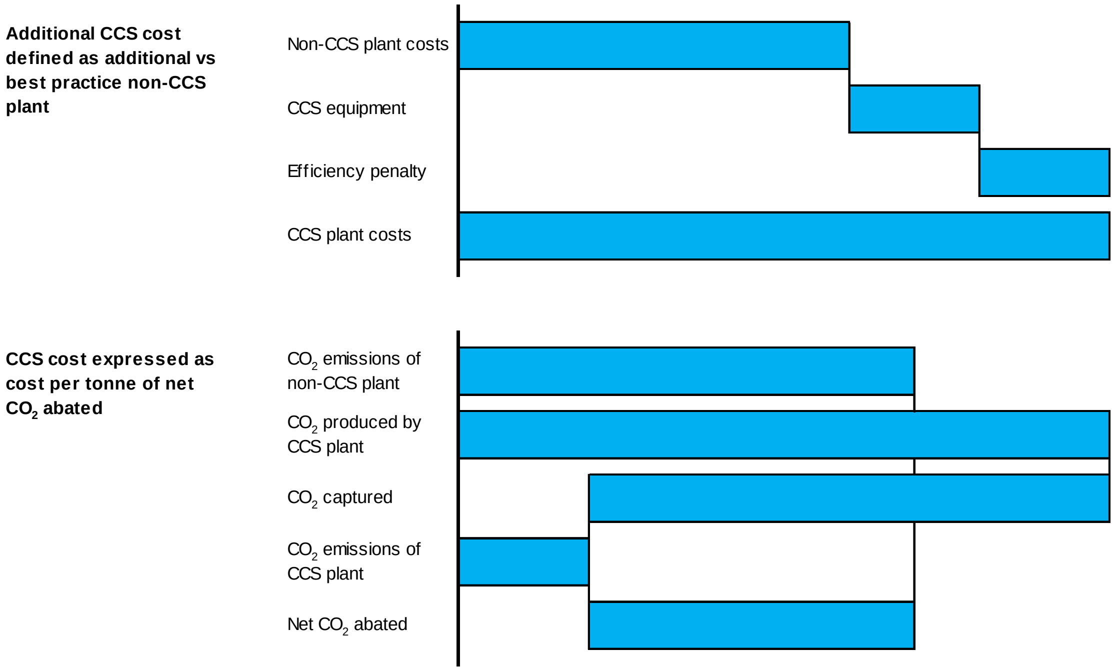
6.2. Carbon Capture and Storage Costs

There is a high degree of uncertainty in estimating the costs for CCS because of significant variations between the technical characteristics, scale and application of a project. There is also uncertainty of how CCS costs will develop over time given the wide range of potential learning rates and scale benefits, and the variability of input costs such as materials, engineering and fuel.

However, the development of CCS costs over time for new build coal power plant based on consistent reference cases has been assessed in numerous studies. One approach (McKinsey, 2008) defines the "cost of CCS" as the initial investments and ongoing operational expenditures of a CCS power plant compared to the cost of a best practice non-CCS plant of the same net electrical output using the same fuel. The cost includes the CO_2 capture at the power plant, its transport and permanent storage.

The cost of CCS was expressed in real terms in Euros per tonne of net CO_2 emissions reduction, outlined in **Figure 6-1** below. The costs were assessed on the basis of 90% capture of CO_2 emissions produced by the CCS equipped power plant.

- **Figure 6-1 Approach followed in cost of CCS analysis (McKinsey, 2008)**



The cost of CCS was evaluated at different stages of development – from initial demonstration projects, to early commercial and eventually mature commercial projects.

Given their smaller scale (300 MW) and focus on proving technologies rather than optimal commercial operation, the initial demonstration projects starting from 2015 were found to typically cost between €60-90/tCO_2 (AUD100-150/tCO_2).

The early full commercial scale CCS projects (900MW) starting from 2020 were estimated to cost between €35-50/tCO_2 (AUD60-85/tCO_2).

For the mature commercial CCS projects starting from 2030 (assuming 80-120 projects beforehand) the cost of CCS was estimated at €30-45/tCO_2 (AUD50-75/tCO_2). This cost would depend on several factors including the learning effect on development of the technology, its economies of scale, the availability of favourable storage locations and the actual roll-out realised.

The retrofitting of an existing power plant with CCS would lead to a higher cost of CCS than the figures quoted above. The costs are very dependent on site specific characteristics such as plant specifications, remaining economic life and site layout.

There were found to be four major factors likely to result in increased cost to retrofit CCS including:

- Higher capex of capture plant due to space constraints making the CCS adaption more difficult than new build;
- Shorter lifespan of the power plant resulting in increased capex component of CCS costs;
- Higher efficiency penalty compared to a fully integrated new build CCS plant; and
- Opportunity cost of lost power generation during shutdown period to install retrofitted CCS.

It was estimated that retrofitting was unlikely for plants older than 10 years as the total CCS cost would be at least 30% higher than that of new power plants. It was considered that a possible exception to this would be for very efficient plants less than 5 years old built CCS ready and the retrofit planned to minimise shutdown time, then the additional CCS costs could be 10% or lower.

The $/t$CO_2$ cost of CCS (post combustion) will be significantly higher for natural gas fired CCGT plant than coal fired plant. The major driver of higher cost is the flue gas which is produced in much higher volumes and with 25-30% less CO_2 concentration compared to coal plant. Therefore much of the CCS plant would have to be significantly larger and more expensive to capture an equivalent mass of CO_2. In addition, as the fuel cost is higher for natural gas compared to coal, the efficiency penalty to operate the carbon capture plant translates to a higher CCS $/t$CO_2$ cost.

6.3. Comparison to CPRS costs

The impact of CPRS and the installation of CCS on the cost of generating power is given in **Table 6-1** below.

As CCS in not currently commercially available, the Mt Piper Extension USC coal power plant would need to be built as CCS ready to facilitate future retrofit of CCS.

A CPRS cost of $50/t$CO_2$ may be sufficient to make the retrofitting of CCS to a USC coal power plant economic (ie CPRS permit cost ≈ levelised cost of CCS installation and operation). CPRS costs of $10/t$CO_2$ or $25/t$CO_2$ would be insufficient to support the retrofit of CCS and the impact on the power production cost would be $8.10/MWh and $20.30/MWh respectively.

As the retrofit cost of CCS for natural gas fired CCGT plant is likely to be significantly higher than a CPRS cost of $50/t$CO_2$ it will not be economic (ie CPRS permit cost < levelised cost of CCS installation and operation). CPRS costs of $10/t$CO_2$, $25/t$CO_2$ or $50/t$CO_2$ would be insufficient to support the retrofit of CCS for natural gas fired CCGT plant and the impact on the power production cost would be $3.60/MWh, $9.00/MWh and $17.90/MWh respectively.

- **Table 6-1 Costs of CPRS and CCS on production in MWh sent out**

	Coal USC	**Gas CCGT**
Without CCS		
CPRS $10/tCO$_2$	$8.10/MWh	$3.60/MWh
CPRS $25/tCO$_2$	$20.30/MWh	$9.00/MWh
CPRS $50/tCO$_2$	$40.60/MWh	$17.90/MWh
With CCS [1]		
2020	$50-70/MWh	$26-37/MWh
2030	$40-60/MWh	$22-32/MWh

1. Assuming $/tCO$_2$ cost of CCS for CCGT plant is 20% more than for USC plant

7. Conclusions

This report has provided an assessment of greenhouse gas issues for the proposed Mt Piper Power Station Extension project. In particular, the current state of knowledge of greenhouse gas issues has been discussed, as well as Australia's position with respect to climate change action.

Greenhouse gas emissions have been estimated for the two project options; namely, an ultra-supercritical coal-fired plant or a combined cycle gas turbine plant. The direct (Scope 1) and indirect (Scope 2 and 3) emissions have been estimated, and are summarised as follows:

- 10.47Mt CO_2-e of direct emissions for the USC proposal (Scope 1)
- 4.91Mt CO_2-e of direct emissions for the CCGT proposal (Scope 1)
- 10.92Mt CO_2-e of total (direct and indirect) emissions for the USC proposal (Scope 1,2,3)
- 7.03Mt CO_2-e of total (direct and indirect) emissions for the CCGT proposal (Scope 1,2,3)

These estimates can be compared Australia's net GHG emission estimates for 2006 of 287Mt CO_2-e for stationary sources from the energy sector and 401Mt CO_2-e for the total energy sector.

Carbon Capture and Storage (CCS) is suggested as the means by which greenhouse emissions from the proposed extension would be considered. There are no fully integrated commercial scale CCS projects in operation.Carbon capture technologies are based on those that have been applied in the chemical and refining industries for many years, but the incorporation of this technology in the specific context of power generation remains to be demonstrated.

Initially CCS costs are expected to be of the order of €60-90/tCO_2 (McKinsey, 2008) or approximatelyAUD100-150/t CO_2 for coal fired plant, though decreasing as the technology develops. The trigger point for the implementation of carbon capture and storage will be when the cost of implementing CCS reduces to less than the cost of carbon emissions under the operating carbon trading scheme. Given the uncertainty in the capital costs of CCS technology due to its pre-commercial status and also the uncertainty in projected cost of CO_2 emissions under the Federal Government's proposed Carbon Pollution Reduction Scheme (CPRS) it is not possible to make a reasonable assessment of the trigger point for CCS implementation. However as CCS technology matures and the CPRS becomes operational assessment of whether the trigger point has been reached should be made periodically.

As CCS in not currently commercially available, the Mt Piper Extension USC coal power plant would need to be built as CCS ready to facilitate future retrofit of CCS. A CPRS cost of \$50/tCO_2 may be sufficient to make the retrofitting of CCS to the plant economic. CPRS costs of \$10/tCO_2 or \$25/tCO_2 would be insufficient to support retrofit of CCS and the cost to the plant would be \$105 million and \$264 million per annum respectively.

As the retrofit cost of CCS for natural gas fired CCGT plant is likely to be significantly higher than a CPRS cost of \$50/tCO_2 it will not be economic. The cost to the plant would be \$50, \$125 and \$250 million per annum respectively for CPRS costs of \$10/tCO_2, \$25/tCO_2 and \$50/tCO_2 respectively.

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Appendix A Commercial USC Plant

Operating bituminous coal plants worldwide with steam temperatures above 600°C typical boiler data are:

Wilhelmshafen Germany	595 kg/s, 271 bar, 603°C, 621°C
Walsum 10 Germany	596 kg/s, 290 bar, 603°C, 621°C
Datteln – 4 Germany	816 kg/s, 304 bar, 600°C, 620°C
Moorburg Germany	580 kg/s, 304 bar, 600°C, 610°C
Beilun China	832 kg/s, 275 bar, 605°C, 603°C
Torrevaldaliga Nord Italy	533 kg/s, 252 bar, 604°C, 612°C
Zouxian China	843 kg/s, 262 bar, 605°C, 603°C
Hitachi-Naka Japan	794 kg/s, 275 bar, 603°C, 601°C
Tachibanawan Japan	833 kg/s, 285 bar, 605°C, 613°C
Haramachi Japan	803 kg/s, 280 bar, 604°C, 602°C