HRL Developments Pty Ltd
ACN 093 163 663

Level 1, Unit 9
677 Springvale Road
Mulgrave Victoria 3170 AUSTRALIA

Phone: 03 9565 9888
Fax: 03 9565 9866

Prepared by

HRL DEVELOPMENTS

SUMMARY DOCUMENT DESCRIBING : IDGCC PROCESS DESCRIPTION, CALCULATION OF GREENHOUSE EMISSIONS AND BEST PRACTICE

September 2011

by Alex Blatchford

SIGNED: Alex Blatchford
DATE: 26th SEPTEMBER 2011

1. INTRODUCTION

1.1. Report Introduction

The intention of this report is to provide a summary of the following areas :

- The Integrated Drying Gasification Combined Cycle (IDGCC) process and the Dual Gas Demonstration Project (DGDP);
- The methods used for calculating the greenhouse gas emissions from the DGDP;
- An assessment of best practice with respect to the overall performance of the DGDP.

1.2. Introduction to HRL Limited

HRL Limited (HRL) is an Australian owned energy, technology and project development company.

The **Dual Gas Demonstration Project's (DGDP)** proponent is **Dual Gas Pty Ltd (DGPL)**, which is a special purpose company created by HRL to build, own and operate the Dual Gas Demonstration Power Station (DGDPS).

1.3. Statement Regarding Expert's Expertise to Make the Report

The author has 17 years experience as a process engineer in coal gasification with HRL's IDGCC technology and has had a senior design role for the DGDP.

The author has worked for a number of years in the provision of greenhouse consulting to the generation industry, including compliance and greenhouse emissions reporting under a variety of State and Federal government schemes (including GES, GGAS and NGER).

Further details on the authors experience are provided in Section 5.

1.4. Author's Involvement in Preparation of Works Approval Document

The author's main role in preparation of the Works Approval Document was to assist SKM in the preparation of the Greenhouse Gas Assessment (Appendix D of the Works Approval Document), through provision of the base inputs used in the modelling (eg coal and natural gas analysis and flowrates for each case), as well as providing input into the content of the report and review of report drafts.

The author also assisted SKM in providing technical input into the rest of the Works Approval Document, including water demand, use of air cooled condensers, estimation of solid wastes and overall mass and energy balances.

The author also assisted in determining the emissions rates used for the Air Quality Assessment Report (Appendix C of the Works Approval document).

2. DESCRIPTION OF IDGCC PROCESS

2.1. Introduction to IDGCC

The Integrated Drying and Gasification Combined Cycle (IDGCC) Technology is a process for generating power from low rank brown coal. The brown coal is dried and then converted to a gas (otherwise known as synthesis gas or syngas), which is burnt to produce power in a gas turbine. The power station will use a combination of natural gas and syngas as fuel for the gas turbines.

Integrated refers to the use of drying and gasification technologies that has been optimised for the plant's combined cycle.

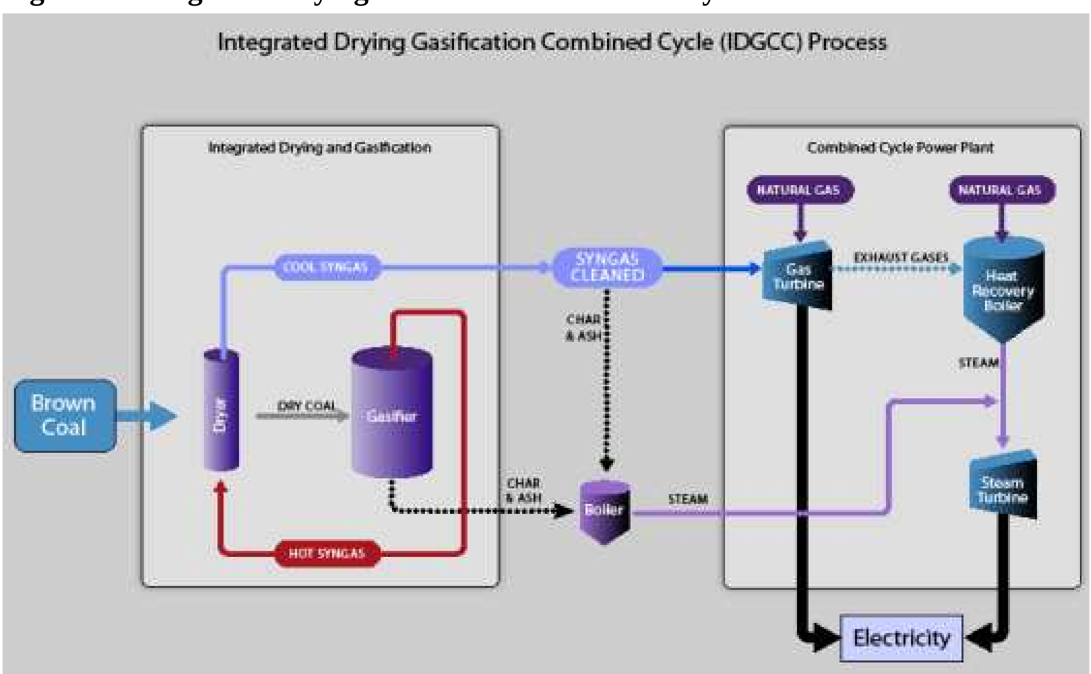
Drying refers to the process of reducing the moisture content of the coal prior to gasification.

Gasification refers to the process of converting the dry brown coal into a gas for supply as a fuel to the gas turbine.

Combined Cycle refers to the use of both a gas turbine and a steam turbine to generate power, with the hot exhaust from the gas turbine being used to generate steam, which is used to generate additional power in the steam turbine.

Figure 1 shows the major components of the IDGCC Technology.

Figure 1 : Integrated Drying Gasification Combined Cycle Process



The gasification process occurs in a 'gasifier' which is a vessel containing a fluidised bed of solid (granular) char particles (formed from the dry coal feed) that operates at high temperature and pressure. The bed is fluidised and mixed by bubbles of gas generated from the reaction of coal and char within the bed with the supply of air into the gasifier. This reaction also provides the heat that increases the temperature of the bed.

Brown coal from the Latrobe Valley is very wet, with a moisture content of around 60%. The efficiency of the gasification process is increased by using the hot syngas produced by the gasifier to dry the coal prior to feeding into the gasifier.

The syngas is then cleaned by removing solid particulate matter (such as char and ash) in a high efficiency ceramic filter. Further cleaning of the gas is conducted by passing the syngas through an ammonia scrubber, which removes up to 95% of the ammonia present in the gas, which would otherwise combust in the gas turbine to form NO_x in the stack gases.

Power is generated by combusting syngas or natural gas in a gas turbine. The hot turbine exhaust gases are used to generate steam in a Heat Recovery Steam Generator (or HRSG), and the steam is used to generate additional power in a steam turbine. Supplementary natural gas can also be supplied or fired directly into the HRSG for the generation of additional steam and hence power in the steam turbine.

The solid residues from the process (namely char and ash) are burnt in a conventional boiler to generate steam, which is also supplied to the steam turbine to generate additional power.

2.2. Introduction to the Dual Gas Demonstration Project (DGDP)

2.2.1. Plant Configuration

Dual Gas Pty Ltd (Dual Gas) proposes to develop a new 600 MW power station to generate base load power whilst demonstrating the IDGCC technology at commercial scale at a site in Morwell, Victoria.

The power station is proposed to be comprised of :

- 2 integrated drying and gasification (IDG) plants;
- 2 gas turbines (GTs);
- 2 heat recovery steam generators (HRSGs);
- 1 steam turbine and generator (ST);
- 1 air cooled condenser (ACC);
- 2 char burners.

The design of the plant is such that the steam generated from the two HRSG’s and the two char burners are supplied to a single steam turbine. This proposed configuration reduces the capital costs associated with the use of two steam turbines, as well as benefiting from increased efficiency of operation from a larger steam turbine and generator set.

2.2.2. Construction Timing

It is proposed that DGDP be constructed in two phases.

- Stage 1 : construction of the combined cycle power plant (ie the 2 gas turbines, the 2 HRSGs and the one steam turbine) and the first Integrated Drying and Gasification (IDG) Plant No.1;
- Stage 2 : construction of Integrated Drying and Gasification (IDG) Plant No.2.

It is expected that construction of Stage 1 will take approximately 2 years. Construction of Stage 2 is expected to be started after the start of operation of Stage 1.

2.2.3. Plant Location

The plant is proposed to be constructed within the Energy Brix Australia Corporation (EBAC) site, located approximately 1 km south of the Morwell township. The existing cogeneration facility on the site consists of the Energy Brix Power Station, a 190 MW brown coal fired power station, which supplies electricity to the retail market, as well as steam to the adjacent Energy Brix briquette works.

2.2.4. Technical Differences between a 300 MW and a 600 MW Plant

As presented in Section 2.2.1 the proposed configuration for the 600 MW plant is for two gasifier blocks, two gas turbines, two HRSG's, one steam turbine, one air cooled condenser (ACC) and two char burners. Delaying the approval of the second 300 MW unit will require changes to the design of the plant including the use of two smaller steam turbines, two circulating water systems and two ACCs.

As a rule, the larger the plant size, the greater the benefit from economies of scale, including cost (capital, operating, maintenance and spares) and plant performance. Having a larger (single) steam turbine allows the use of higher steam pressures and lower HP steam leakage rates which results in a marginally more efficient steam cycle.

The use of a 2 (gas turbine) x 2 (HRSG) x 1 (steam turbine) configuration is a very common and often preferred configuration, offered by all of the major combined cycle suppliers.

Table 1 : DGDP Plant Specification

	Configuration for which Permission was Sought	Configuration if an Additional 300 MW of Capacity is Added to the Permitted Development	Configuration of 300 MW Plant in Isolation
Gasifier Blocks	2	2	1
Gas Turbines	2	2	1
HRSGs	2	2	1
Steam Turbines	1	2	1
ACC	1	2	1
Char Burner	2	2	1

2.3. IDGCC Development History

HRL's IDGCC Technology has been developed over a period of more than 20 years, initially prompted by the Victorian Government Natural Resources & Environment Committee inquiry (1985-88) into Electricity Supply & Demand Beyond the Mid-1990s.

Since initial development, more than $150 million has been spent on developing and proving the IDGCC technology. The IDGCC technology development pathway has included:

- process and economic modelling and laboratory-scale testing;
- the development and operation of a 0.5MW Coal Gasification Demonstration Unit (CGDU) at Mulgrave, in the south-eastern suburbs of Melbourne. Initially the CGDU demonstrated the gasification of a range of coals. In more recent times it has been operated to supply a syngas stream for pre-combustion carbon capture trials;
- the development and operation of a 10MW Coal Gasification Development Facility (CGDF) near Morwell in the 1990s in the Latrobe Valley. The CGDF (as shown in Figure 2) successfully demonstrated the IDGCC process from coal preparation through to syngas combustion in a grid-connected 5MW gas turbine.

This proposed development is the fourth stage of the IDGCC technology development pathway and aims to demonstrate the IDGCC technology at commercial-scale.

If this fourth stage is successful, a further extension is expected to be the combining of IDGCC with commercially proven carbon capture (CC) technology. On 20 January 2010, the Victorian Government announced "Cleaner Energy Projects Share in up to $29 Million". This announced that HRL will be provided with a grant of up to $3.5 million to investigate the feasibility of a pre-combustion CO_2 capture project.

2.4. Australian and Victorian Government Support for DGDP

The Australian Government set up the $ 500 million Low Emissions Technology Demonstration Fund (LETDF) to help Australian firms commercialise world-leading low emissions technologies. In 2007 HRL was awarded $ 100 million under this scheme for the Dual Gas Demonstration Project.

Initiated in 2005, the Victorian Government set up the Energy Technology Innovation Strategy (ETIS) to drive advances in low emission technologies. The strategy aims to accelerate a variety of pre-commercial energy technologies through research, development, demonstration and deployment, such that they are ready for market-uptake. In 2006 HRL was awarded $ 50 million of funding for a large-scale IDGCC power station (DGDP).

In the 2008-09 State Budget the Victorian Government allocated $ 110 million to expand ETIS to include the Carbon Capture and Storage Large Scale Demonstration Program (CCS LSDP). Of this fund $ 29 million has been allocated to five projects to explore the development of large pre-commercial demonstration of CCS in the Latrobe Valley. This includes funding of up to $ 3.5 million being allocated to HRL to investigate the feasibility pre-combustion CO_2 capture with HRL's IDGCC technology.

Figure 2 : Coal Gasification Development Facility (CGDF)

2.5. Existing and Planned IGCC and Gasification Plants Worldwide

2.5.1. Existing IGCC Plants

There are a total of six IGCC plants in the world that operate using coal as a fuel, as summarised in Table 2[1], with a total syngas capacity of 3,181 MW_{th}. In addition to these plants there are a further eleven IGCC plants that use other fuels, such as petroleum, biomass or petcoke (with a total syngas capacity of 4,931 MW_{th}).

Table 2 : Existing IGCC Plants

Plant	Country	Technology	Year	Fuel	Syngas Capacity MW_{th}
Polk County	USA	GE	1996	Coal/Petcoke	451
Buggenham	Netherlands	Shell	1994	Coal	466
Vresova	Czech Rep	Sasol Lurgi	1996	Coal	636
Puertollano	Spain	Uhde Prenflo	1998	Coal	588
Wabash River	USA	E-Gas	1995	Coal/Petcoke	591
Nakoso	Japan	MHI	2007	Coal	449

2.5.2. Planned IGCC Plants

There are a total of fifteen IGCC plants listed in the U.S. Department of Energy (DoE) Gasification database that are in various stages of development (including development, pre-FEED, FEED, planning and construction), using coal or petcoke as the fuel, with a total syngas capacity of 19,000 MW_{th}.

There are four plants currently under construction, are as follows (with a total syngas capacity of 4,510 MW_{th}) :

Table 3 : IGCC Plants under Construction

Plant	Country	Technology	Year Expected	Fuel	Syngas Capacity MW_{th}
Edwardsport	USA	GE	2011	Coal	1,150
Kemper County	USA	TRIG	2014	Coal	685
Magnum[2]	Netherlands	Shell	2012	Coal	1,925
GreenGen	China	ECUST	2011	Coal	750

[1] Data sourced from the DoE Gasification Database : http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/index.html

[2] It was recently announced that the gasification part of the power plant will not be brought online until after 2020.

In general, there is a strong global growth in the use of gasification technology for a range of products, including chemicals, liquid fuels, power and gaseous fuels, as shown by the following Figures. The growth of gasification using coal for the power sector is particularly strong.

Figure 3 : Global Gasification Capacity and Planned Growth[3]

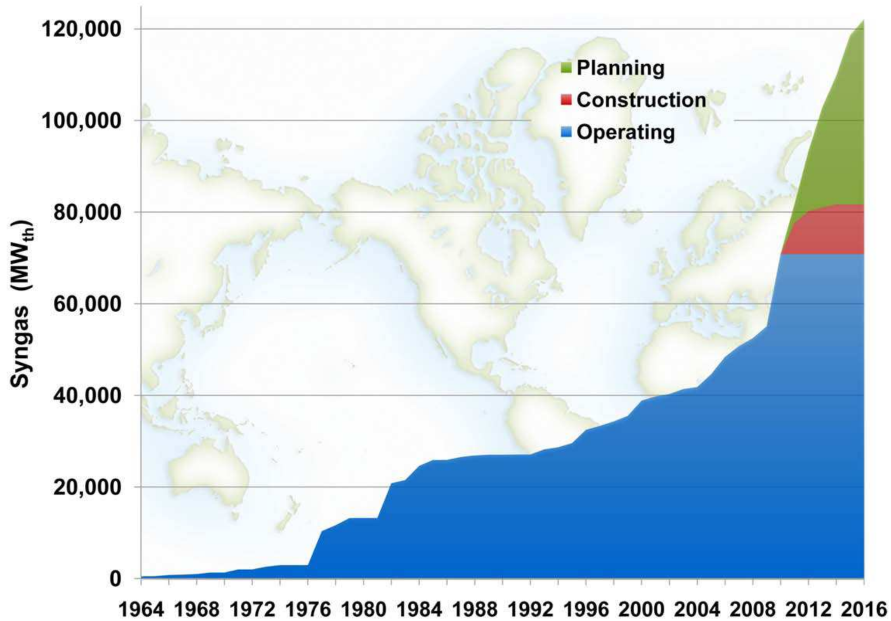
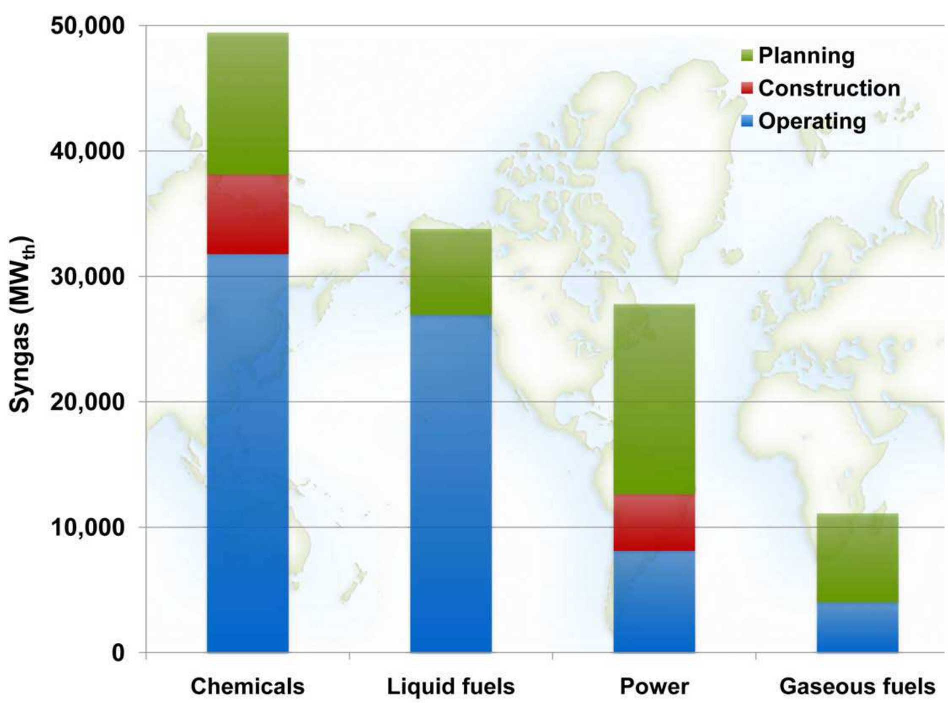


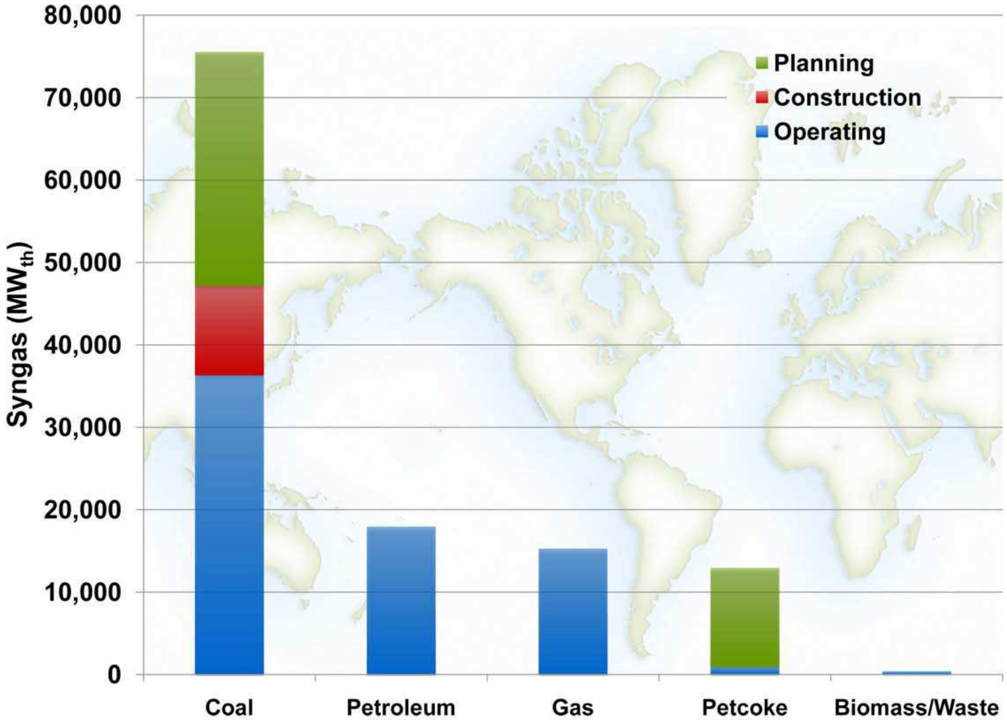
Figure 4 : Global Gasification Capacity and Growth by Product



---

[3] Sourced from : **http://www.netl.doe.gov/technologies/coalpower/gasification/worlddatabase/summary.html**

Figure 5 : Global Gasification Capacity and Growth by Feedstock



2.5.3. Conclusion

The development of the pressurised drying with the off-gases from the gasifier with the patented IDGCC technology is unique amongst the current fleet of IGCC gasification technologies listed in Table 2 and other available gasification technologies. This method of drying the coal eliminates the need for expensive and / or inefficient pre-drying. It also eliminates the need for an expensive and very large syngas cooler, which has a need to operate at high temperatures and pressures.

In the IDGCC technology air is supplied to the gasifier. All but one of the currently operating IGCC plants are oxygen blown, and operate at high gasification temperatures. This requires the use of an Air Separation Unit (ASU) to produce the oxygen, which increases the capital and operating costs, and also consumes a significant amount of power, reducing the sent out power.

The DGDP is distinctive and unique compared with other IGCC gasification plants worldwide and allows the generation of power from high moisture content brown coals in a cost effective and efficient manner.

3. CALCULATION OF GREENHOUSE GAS EMISSIONS

3.1. Introduction

Dual Gas Pty Ltd commissioned Sinclair Knight Merz (SKM) to conduct the Works Approval Assessment for DGDP, including calculation of the greenhouse gas emissions (Greenhouse Gas Assessment, Appendix D of the Works Approval Document).

The author assisted SKM in the preparation of the Greenhouse Gas Assessment, through provision of the base inputs used in the modelling (eg coal and natural gas analysis and flowrates for each case), as well as providing input into the content of the report and review of report drafts. This section summarises the approach used in calculation of the greenhouse gas emissions and draws from SKM's Greenhouse Gas Assessment report.

3.2. Summary of Calculation Methods Used

The *National Greenhouse and Energy Reporting Act 2007* (the NGER Act) was passed on 29th September 2007, establishing a mandatory reporting system for corporate Greenhouse Gas (GHG) emissions and energy production and consumption in Australia. The first reporting period under the Act commenced on the 1st July 2008.

Corporations must meet the requirements of the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (the NGER Determination), which is essentially a handbook outlining the methods and approaches to be used, in order to comply with the technical aspects of reporting.

The calculation of the greenhouse gas emissions for DGDP are consistent with the NGER Act and the NGER Determination.

3.3. Definition of Emissions Scope

According to the NGER Act, corporations are required to report Scope 1 and Scope 2 GHG emissions. The NGER legislation does not cover reporting of Scope 3 emissions. The emissions and hence emissions intensity are calculated on the basis of Scope 1 emissions (there are no associated Scope 2 emissions, as described below). This approach is consistent with Section 2.1 of the Protocol for Environment Management, Greenhouse Gas Emissions and Energy Efficiency in Industry. This is also consistent with standard industry practice and other State and Federal Government greenhouse reporting or abatement schemes, such as the Australian Government's Generator Efficiency Standards (GES), and the NSW Government's Greenhouse Gas Reduction Scheme (GGAS).

Scope 1 emissions are the release of greenhouse gases into the atmosphere as a direct result of the activities of the facility. For the DGDP this includes the GHG emissions as a result of consumption and combustion of brown coal and natural gas.

Scope 2 emissions are the release of greenhouse gas into the atmosphere as a result of activities that generate electricity, heating, cooling or steam that is consumed by the facility but that do not form part of the facility. For the DGDP Scope 2 emissions are not relevant, as the facility is an electricity generator (not a consumer) and does not require heating, cooling or steam from third parties for its operation.

Scope 3 emissions are other indirect emissions (not covered in Scope 2). The emissions are a consequence of the activities of a company, but occur from sources not owned or controlled by the company. This may include emissions from the supply of materials used in the construction of the plant (eg concrete and steel) or other purchased materials or goods, transport and disposal of waste generated, extraction, production and transport of purchased fuels consumed, travel by employees, and disposal (end of life) of products sold. Scope 3 emissions are aimed at assessing or reducing the life cycle emissions of an entity's products or services.

3.4. Carbon Dioxide Equivalence

There are a large number of gaseous emissions that have an impact on global warming. Carbon dioxide equivalence is a measure used to compare the emissions from various greenhouse gases based on the global warming potential. For example the emissions of one million tonnes of methane is equivalent to 21 million tonnes of carbon dioxide.

All emissions from all greenhouse gases emitted from the DGDP are calculated on a carbon dioxide equivalence basis, and summed to calculate the total carbon dioxide equivalent emissions. This approach is consistent with the NGER methodology. The main greenhouse gases for the DGDP are carbon dioxide, methane and nitrous oxide.

3.5. Method used for Calculation of Emission Factor

There are four allowable methods in the *NGER Determination* for calculating the emission factor from the combustion of fuel under NGER. The emission factor (typically with units of kg of CO_2-e emitted per gigajoule of energy in the fuel) is multiplied by the quantity of fuel supplied to determine the CO_2 emissions. There is a separate emission factor for each fuel and for each GHG (carbon dioxide, methane and nitrous oxide).

- Method 1 (or the default method) which is derived from the National Greenhouse Accounts methods (or equivalent), based on national average estimates; and
- Method 2 is a facility specific method using industry practices for sampling and Australian or equivalent standards for analysis (to determine carbon content);
- Method 3 is the same as Method 2, but is based on Australian or equivalent standards for both sampling and analysis;
- Method 4 allows continuous or periodic emissions (stack) monitoring for the facility.

Reporting under NGER is intended for use by installed and operating plant. For proposed plant, such as the DGDP, the monitoring of stack emissions (Method 4) or the use of Australian standards for sampling and analysis (Method 3) clearly do not apply (as this relates to ongoing sampling and analysis for an operating plant). However, the facility specific calculation procedures given under Method 2 have been used for estimation of carbon dioxide emissions from natural gas and brown coal, using the carbon content of the fuels proposed to be used in the plant. For emissions of methane and nitrous oxide, Method 1 must be used, as directed by NGER Determination (eg see Section 2.3 of NGER Determination for calculation of emissions from solid fuels), and therefore has been used for calculation of these emissions from the DGDP.

3.6. Calculation of Emission Factors

3.6.1. Calculation of Emission Factors using Methods 1 and 2

Although coal is supplied to the power station, the coal is converted to syngas, which is combusted in the gas turbines, and residual char from the gasifier is combusted in the char burners. For emissions of CO_2 due to combustion of carbon in the fuels supplied, the NGER methodology determines the total carbon input in the fuel supplied to the power station, and the proportion of the input carbon that is combusted, ie there is no requirement to determine emission rates from different sources.

The Scope 1 emissions for both fuels (coal and natural gas) and for all three greenhouse gases (carbon dioxide, methane and nitrous oxide) for each fuel using Methods 1 and 2 are calculated using the following equation (*NGER Determination*, Section 2.20):

Equation 1 : Calculation of GHG Emissions for each Greenhouse Gas and Fuel Type

$$E_{ij} = \frac{Q_i \ x \ EC_i \ x \ EF_{ijoxec}}{1{,}000}$$

Where :

E_{ij} is the emissions of greenhouse gas type (j), being carbon dioxide, methane or nitrous oxide, released from the combustion of fuel type (i), ie natural gas or coal, during the year, measured in CO_2-e tonnes;

Q_i is the quantity of fuel (i) consumed, measured in tonnes for coal, and gigajoule (GJ) for natural gas;

EC_i is the energy content of the fuel (i) measured in GJ per tonne of fuel for coal (value of 1 used for natural gas (NGER Determination Section 6.5));

EF_{ijoxec} is the emission factor for each greenhouse gas type (j) (including oxidation factor) released from the combustion of fuel type (j) measured in tonnes of CO_2-e per GJ of energy in the fuel.

The carbon dioxide (j) emission factor for coal (i) is calculated using the following equation (*NGER Determination*, Section 2.5) :

Equation 2 : Calculation Emission Factor (EF_{ijoxec}) for CO_2 (j) and Coal (i)

$$E_{coalCO_2oxec} = \frac{\frac{C_{ar}}{100} \ x \ OF_s \ x \ 3.664}{EC_{coal}}$$

Where :

C_{ar} is the percentage of carbon in coal on an as received (ie wet) basis;

OF_s is the oxidation factor (or fraction of carbon in the fuel that is converted to CO_2);

The factor of 3.664 is applied to convert the mass of carbon in the coal to the mass of carbon dioxide emitted (ie the ratio of molecular weights of CO_2 to C).

The CO_2 emission factor for natural gas was calculated using the natural gas analysis presented in Table 6, and using the methodology as outlined in Section 2.22 of the *NGER Determination.*

3.6.2. Brown Coal Emission Factor

DGDP has two possible sources of coal, namely Yallourn North Extension (YNE) coal or Morwell Open Cut (MOC) coal. To determine the emission factor (as per the NGER equations presented above) from each coal (EF_{ijoxec}) a coal analysis was used which is representative of each coal resource.

Table 4 : DGDP Coal Analysis

	Units	MOC Coal	YNE Coal
Coal Moisture	% ar	61.0%	52.3%
Coal Carbon Content	% dry basis	68.4%	65.7%
	% as received	26.7%	31.4%
Coal Heating Value	GJ / tonne	10.40	12.40

From the data in the table above the emission factors were calculated (using Equation 2), together with the default emissions factors for CH_4 and N_2O (from the NGER Determination, Schedule 1). An assumption has been made that all the carbon in the brown coal will convert to CO_2 (ie an oxidation factor of 1.00 has been used), which is a worst case assumption in terms of emissions of CO_2 per tonne of brown coal supplied to the station.

Table 5 : DGDP Coal Emission Factors

	Units	MOC Coal	YNE Coal
CO_2 emission Factor	kg CO_2-e / GJ	94.01	92.59
CH_4 Emission Factor	kg CO_2-e / GJ	0.01	0.01
N_2O Emission Factor	kg CO_2-e / GJ	0.40	0.40
Overall Emission Factor	kg CO_2-e / GJ	94.42	93.00

3.6.3. Natural Gas Emission Factor

The following analysis was used to determine the emission factor for natural gas.

Table 6 : DGDP Natural Gas Analysis

	Mole %		**Mole %**
Methane	90.03%	Oxygen	0.10%
Ethane	5.84%	Nitrogen	0.7947%
Propane	1.12%	Carbon Dioxide	1.907%
Butane	0.2083%		

The CO_2 emission factor for natural gas was calculated using the natural gas analysis presented in Table 6, and using the methodology as outlined in Section 2.22 of the *NGER Determination*. The CH_4 emission factor was calculated from the IPCC (2006) Guidelines (as per NGER Determination Section 2.27). The N_2O emission factor is the Method 1 value.

Table 7 : DGDP Natural Gas Emission Factors

	Units	
Heating Value	MJ/kg or GJ/t	51.763
CO_2 emission Factor	kg CO_2-e / GJ	50.92
CH_4 Emission Factor	kg CO_2-e / GJ	0.086452
N_2O Emission Factor	kg CO_2-e / GJ	0.03
Overall Emission Factor	kg CO_2-e / GJ	51.045

3.7. Plant Operating Mode and Case Definition

The plant can have a number of operating modes. These include :

- Operation of the GTs on syngas;
- Operation of the GTs on natural gas;
- Operation of the GTs on a mixture of syngas and natural gas;
- Operation of the GTs on any combination of the above plus additional supplementary natural gas use for duct firing of the HRSG.

The fuel mix over the operating life of the DGDPS is expected to be determined primarily by NG prices, electricity prices, plant availability, cost and quality of coal, contractual arrangements for gas supply, the reliability of the gasification process and the price of GHG emission permits.

Also, as stated above, the plant could have two possible coal sources, from the Morwell Open Cut and from the Yallourn North Extension mine.

To cover the range of possible operational scenarios over the life of the project (of 30 years), four cases have been developed, as described below, and the greenhouse gas emissions calculated for each.

Case 1

- Two gasifier operation;
- Morwell coal used for an initial 4 year period;
- YNX coal used for a subsequent 11 year period;
- Morwell coal used for the final 15 years of the project;
- Using a relatively large amount of natural gas (11,425 TJ per annum on average).

Case 2

- Two gasifier operation;
- The same coal sources as outlined in Case 1;
- Using a moderate amount of natural gas (8,715 TJ per annum on average).

Case 3

- Two gasifier operation;
- Morwell coal used for the 30 year plant life;
- Using a moderate amount of natural gas (9,518 TJ per annum on average).

Case 4

- One gasifier operation, ceasing after 4 years (IDGCC non-success case);
- Morwell coal used for 4 years;
- Fuelled by natural gas only for the remaining plant life (14,108 TJ per annum on average).

3.8. Calculation of Greenhouse Emissions

The quantity of coal and natural gas fuel demand, as well as generated and sent-out power was determined on an annual basis for each of the four cases outlined above, using process models of the predicted plant performance, planned plant outages and expected electricity market conditions. The annual coal and natural gas consumption data for the four cases are presented in Appendix A.

The plant performance was determined from heat and mass balance modelling of the Integrated Drying and Gasification plant, and modelling of the gas turbine, HRSG and steam turbine performance based on vendor supplied and publically available performance data. Both the IDG and power block modelling were conducted using state of the art, commercial, steady-state process modelling packages.

From the annual quantity of coal and natural gas consumed, and the calculated emissions intensity and heating value for each fuel (presented in Tables 1 to 4 above), the total Scope 1 annual emissions were calculated using Equation 1. The data is presented in Appendix B.

3.9. Calculation of Greenhouse Intensities

For each of the four cases, the greenhouse intensity was calculated.

Greenhouse intensity (tonnes of CO_2-e per megawatt-hour), can be presented on a 'generated' power or on a 'sent out' power basis. The generated power is measured at the generator terminals. The sent out power is the generated power minus the internal (or auxiliary) power consumption in the power station for electrical demands such as pumps, fans, instrumentation, compressors and lighting. The sent out power is therefore always lower than the generated power.

For the purposes of this report greenhouse intensity (or GI) is defined as the total Scope 1 emissions divided by the gross generation, as this is the chosen basis for the Australian Government's GI target for new coal fired power plant. The GI was calculated on an annual basis as well as on a project average basis.

The annual data for each case is presented in Appendix B, with the project average results summarised below.

Table 8 : Calculated Project Average GHG Emissions and Intensity

	Project Average Greenhouse Intensity t CO_2-e / MWh 'generated'	Project Average Greenhouse Gas Emissions Million t CO_2-e / annum
Case 1	0.73	3.024
Case 2	0.77	3.201
Case 3	0.78	3.238
Case 4	0.45	0.762

3.10. Comparison against Federal and State Emission Standards

3.10.1. Victorian State Government

The previous Government in Victoria released its *Victorian Climate Change White Paper – The Action Plan* (July 2010) which included a number of actions aimed at reducing emissions. The Action Plan proposed setting a target emission level of 0.8 tonnes of CO_2-e per MWh for new power stations.

The DGDPS complies with this benchmark.

Subsequently, the *Climate Change Act* was passed by the Victorian Parliament in September 2010, which requires the Minister to ensure that Victoria's GHG emissions are 20 % below year 2000 levels by 2020. The Act also amends the *Environment Protection Act 1970* to enable the Environment Protection Authority Victoria to regulate GHG emissions.

3.10.2. Australian Government

In July 2010 the Australian Government released an election commitment which included the establishment of new emission standards for new coal fired power stations, and that they are Carbon Capture and Storage (CCS) ready[4]. The proposed emissions standard starting point would be below the level at which assistance was proposed by the Government under the Carbon Pollution Reduction Scheme (CPRS), namely 0.86 t CO_2-e / MWh 'generated'.

The DGDPS complies with this emissions intensity benchmark. The DGDPS has been designed to enable the potential retrofit of CO_2 capture technology when commercially viable.

The standard aimed to deliver a strong signal to investors to factor future carbon constraints into their decision making, to move the energy sector towards lower emission forms of generation such as best-practice coal technology, gas and renewables, to encourage investment in low emissions electricity infrastructure and support green jobs and continued economic growth as well as help resolve uncertainty that has being deterring investment in generating capacity.

The Government has established an Interdepartmental Task Group (ITG) to develop these measures, in consultation with energy market institutions, State and Federal Governments, industry and environmental stakeholders[5]. An ITG discussion paper, *A Cleaner Future for Power Stations* was released in November 2010. Written submissions closed on 24th December 2010. The ITG is continuing with the regulatory process in which the stakeholder submissions and consultation will be considered, and Regulation Impact Statements prepared for Government.

3.11. Carbon Tax

At present there is no cost for CO_2 emissions within Australia. An announcement by the Australian Government on 10 July 2011 has indicated the intent to put a price on CO_2 emissions, with a starting price of $ 23 a tonne on 1 July 2012, rising at 2.5 percent a year in real terms. From 1 July 2015, the Government intend that the carbon price will be set by the market. Final details are yet to be clarified and legislation has yet to be passed.

3.12. Carbon Capture Ready

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.

The future retro-fitting of carbon capture technology to DGDPS (if commercially viable), is expected to enable the facility to achieve an expected greenhouse gas intensity of approximately 0.26 t CO_2-e / MWh. Importantly, installation of high efficiency power generation technology will minimise the quantity of carbon dioxide requiring capture, as is the case for DGDPS.

---

[4] http://www.alp.org.au/federal-government/news/tough-emissions-standards-for-new-coal-fired-power/

[5] http://www.ret.gov.au/energy/sustainbility_and_climate_change/domestic_climate_change/cfps/Pages/a-cleaner-future-for-power-stations.aspx

The use of carbon capture is dependent upon the availability of the carbon storage site, a pipeline and its commercial viability.

3.12.1. CCS Flagship Program and CarbonNet

The Australian Government's Carbon Capture and Storage (CCS) Flagships program is designed to accelerate the development and demonstration of CCS technologies, and is part of the Government's Clean Energy Initiative. The Australian Government will fund up to one third of the non-commercial costs of CCS Flagship Projects that are selected.

Four projects were shortlisted and announced by the Minister for Resources, Energy and Tourism on 8^{th} December 2009. The Australian Government is awaiting advice from the Independent Assessment Panel before making a decision on which of the shortlisted projects will be selected for further development and funding.

One of the shortlisted projects, CarbonNet is being proposed by the Victorian Government. CarbonNet is a multi-user CO_2 capture, transport and storage infrastructure proposal for the Latrobe Valley. CarbonNet involves the development of a series of pipelines from high CO_2 emitters in the Latrobe Valley to geological carbon storage sites in proven offshore and onshore areas in Victoria. If successful, the proposal would see Victoria become the location for one of the 20 large-scale carbon capture, transport and storage projects required worldwide, outlined by the G8 as being essential to reduce future global CO_2 emissions. HRL is assisting the Victorian Government in their proposal for CarbonNet.

In the 2008-09 State Budget the Victorian Government allocated $ 110 million to expand the Energy Technology Innovation Strategy (ETIS) to include Carbon Capture and Storage Large Scale Demonstration (CCS LSDP). Of this fund $ 29 million has been allocated to five projects to explore the development of large pre-commercial demonstration of CCS in the Latrobe Valley. This includes funding of up to $ 3.5 million being allocated to HRL to investigate the feasibility pre-combustion CO_2 capture applied to HRL's IDGCC technology.

4. DGDP BEST PRACTICE

4.1. Introduction

Clause 19(1) of State Environment Protection Policy (Air Quality Management) (SEPP (AQM)) requires that a generator of a new source of air emissions must apply best practice to the management of those emissions.

The following definitions, set out in Part IV of the SEPP (AQM), are relevant to the operation of this provision :

(a) Best Practice : 'the best combination of eco-efficient techniques, methods, processes or technology used in an industry sector or activity that demonstrably minimises the environmental impact of a generator or emissions in that industry sector or activity.'

(b) Eco-efficient : 'producing more goods with less energy and fewer natural resources, resulting in less waste and pollution.'

Clause 18 of SEPP (AQM) provides further that, for the purposes of SEPP (AQM), the 'management of emissions' means:

(a) Avoiding and minimising emissions in accordance with the preference established in the principle of the wastes hierarchy; and

(b) The assessment, monitoring, control, reduction or prohibition of emissions for air quality management purposes.

I have been instructed to adopt the following principles in assessing whether the Dual Gas Demonstration Project (DGDP) applies best practice in the management of emissions :

(a) Your assessment of best practice should be conducted having regard to the overall performance of the DGDP in terms of the minimisation of emissions (as opposed to with respect to discrete performance indicators in isolation).

(b) Your assessment of best practice should be conducted with respect to the integrated DGDP as a whole (as opposed to with respect of each of its component parts and processes in isolation);

(c) Your assessment of best practice should proceed on the basis that the relevant 'industry sector or activity' is the brown-coal-fired electricity generation industry sector.

This section outlines how the DGDP meets best practice from the brown coal power generation industry sector, both in terms of the technology and the environmental performance aspects in regards to :

- Efficiency;
- Carbon dioxide emissions;
- Sulphur dioxide emissions;

- Carbon monoxide emissions;
- Nitrous oxide emissions;
- Particulate emissions;
- Water consumption.

My assessment will conclude with an examination of the overall environmental performance of the DGDP when measured against best practice.

4.2. Efficiency

Best practice in regards to all of the main metrics listed above is linked to the high efficiency achievable with IDGCC in comparison with other brown coal fired power plant. With the increased efficiency there is a reduction in coal demand per unit of power generation, and hence an associated reduction in regards to most environmental emissions.

4.2.1. Why High Efficiency is Achievable with IDGCC

In a thermal power station (ie using a boiler and steam turbine or a Rankine cycle), the high pressure requires very strong metals, which limits the maximum practical steam temperature supplied to the steam turbine to 600 – 650°C, and also limits the maximum achievable cycle efficiency (higher efficiencies can be achieved with higher temperatures). In addition, most of the energy of vaporisation of the water is lost as the amount of condensation in the steam turbine is limited due to blade erosion, with the energy being rejected from the cycle from the condenser.

Gas turbines, however, have much higher turbine entry temperatures (up to 1500°C), and the amount of metal exposed to high temperature and pressure is lower. The gas outlet temperature of the gas turbine is also high (450 to 650°C), which is high enough to provide heat for a second cycle, by generating steam in a Heat Recovery Steam Generator (HRSG) and power in a steam turbine. As such, a combined cycle plant has a thermodynamic cycle that operates between the high firing temperature of the gas turbine, and the waste heat temperature of the condenser in the steam cycle, which allows a high cycle efficiency.

Supplementary or duct firing can be used in the DGDP. This allows the gas turbine exhaust temperature to be raised, generating higher pressure and temperature steam, and thereby increasing the steam cycle efficiency. The oxygen content of the gas turbine exhaust is high, hence duct firing reduces the proportional losses due to excess air in the HRSG stack gases. Additional air supply to the HRSG is not required and as the gas turbine exhaust is hot, an air heater is also not required.

In addition to the high combined cycle efficiency achievable compared with conventional thermal plant, there are also additional benefits from the use of the integrated drying and gasification, where the heat in the off-gases from the gasifier is used to dry the incoming coal. The evaporated moisture enters the gas stream (at high pressure) being supplied to the gas turbine, and similar to a steam turbine, additional power is generated in the gas turbine from this steam. The use of this drying technology eliminates the cost of expensive external dryers, which also act to reduce the cycle efficiency due to the energy required to dry the coal.

The gasification reactions also occur at a temperature which is lower than that used by entrained flow gasifiers, thus energy losses in the gasification process can be minimised. To achieve the high temperatures in entrained flow gasifiers, high purity oxygen is required to be supplied to the gasifier, which requires the use of an Air Separation Unit (or ASU). The ASU uses a large amount of power, which also reduces the overall efficiency of the process. The IDGCC technology is an air blown gasification process, avoiding the requirement for an ASU.

4.2.2. Efficiency Comparison of Combined Cycle vs Conventional Thermal Power Plants

The efficiency of the DGDP is between 38.8% to 42.2% (average of 39.4% for Cases 1 to 3) on a generated, higher heating value basis. The efficiency depends upon the relative quantities of natural gas and coal used, and the coal source.

The efficiency of the existing brown coal generators can be calculated from the published greenhouse intensity for each plant (see Section 4.3.1), together with an assumption of the coal quality. The weighted average efficiency for the four main Latrobe Valley brown coal fired power stations is 27.5% (using published generation data). The efficiency of the DGDP plant is 43.3 percent higher than this figure.

The DGDP efficiency is also 14.3% and 15.9% higher than the efficiency of the Australian Greenhouse Office's (AGO) Generator Efficiency Standards (GES) best practice value for an ultra-supercritical pulverised coal plant (USCPC) and a supercritical pulverised coal plant (SCPC).

Table 9 : Comparison of DGDP Efficiency vs Existing Latrobe Valley Generators

	Average Efficiency, %HHV, generated basis	Efficiency Improvement, %
DGDP	39.4%	
Loy Yang A	29.6%	33.0%
Loy Yang B	29.2%	34.8%
Yallourn	26.7%	47.4%
Hazelwood	23.9%	64.7%
Weighted Average	**27.5%**	**43.3%**
GES Best Practice – SCPC	34.0%	15.9%
GES Best Practice – USCPC	34.5%	14.3%

The best performing power station in the world operating on brown coal is the 950 MW Niederaussem K power station in Germany, operated by RWE Power. The power station is an ultra-supercritical pf fired power plant and started operation in 2003. The main steam conditions are 265 bar and 580ºC and the reheat steam conditions are 60 bar and 600ºC. A net thermal efficiency of 43.2% LHV has been reported[6], which equates to a gross HHV efficiency of about 39.7%. It should be noted that the German brown coal has a significantly lower moisture content of 53% compared with Victorian brown coals (there is 39% more moisture per unit of dry coal compared with a 61% moisture content Victorian brown coal).

RWE is also developing a coal drying technology called WTA, which dries the coal using low pressure steam in a fluidised bed. This is a much more efficient means of drying the coal compared with the drying shafts used in conventional power stations, including those in the Latrobe Valley. The Niederaussem K unit (or BoA 1) has been used to trial two prototype dryers, a coarse grain WTA dryer (170 tph of coal feed) and a fine grain dryer (210 tph of coal feed), both drying the coal to a moisture content of about 10%[7].

It should be noted that the WTA technology is not proven to be technically or commercially viable, although RWE are progressing towards this outcome. RWE are to build the next two BoA units without the WTA technology[8].

The performance of the RWE ultra-supercritical plant with and without WTA was modelled by HRL for Latrobe Valley conditions. The model used a 61% moisture content coal, and a 5.5 kPa condenser pressure (which is higher than is achievable in Germany due to higher ambient temperature conditions, resulting in a somewhat lower thermal efficiency). The main and reheat steam conditions were 279 bar, 582ºC and 69 bar / 600ºC respectively.

The model predicted a 34.7% gross HHV thermal efficiency without WTA (similar to the GES New Plant Standard for USCPC of 34.5% shown in Table 9), and 38.6% with WTA. This is lower than the predicted DGDP efficiency of 39.4%.

---

[6] http://leon.fe.uni-lj.si/ekskurzije/ekskurzija05/dokumenti/kraftwerk-niederaussem-englisch-download.pdf

[7] RWE website. http://www.rwe.com/web/cms/mediablob/en/88166/data/88182/4/rwe/innovations/power-generation/fossil-fired-power-plants/fluidized-bed-drying/download-wta-en.pdf

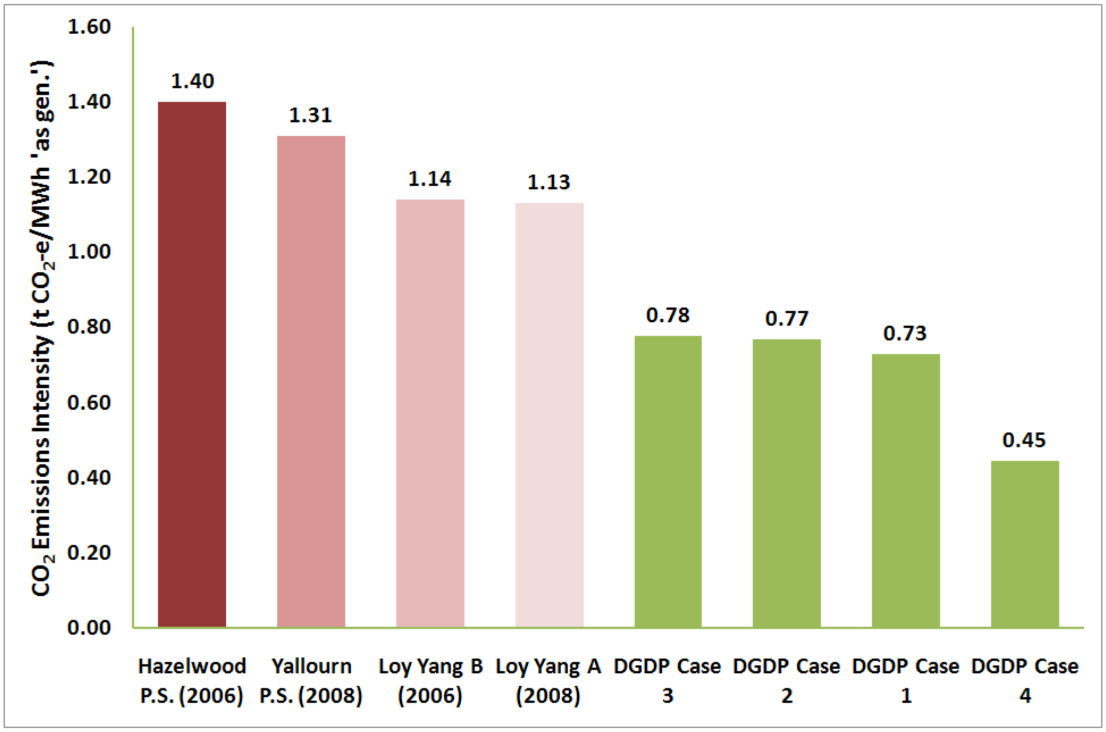
[8] Article from Modern Power Systems, 1st April 2006. http://business.highbeam.com/4364/article-1G1-145328495/rwe-build-boa-2-and-3-without-wta-rwe-power-plans-makes

4.3. Greenhouse Gas Emissions

4.3.1. Benchmarking against Existing Brown Coal Power Stations

The calculated Scope 1 GHG emissions intensities (as generated basis) for DGDPS (Cases 1 to 4) are compared with GGIs from other (existing) Latrobe Valley brown coal power generation facilities in Figure 6[9].

Figure 6 : Greenhouse Gas Intensities : DGDP vs Existing Brown Coal Fired Latrobe Valley Power Stations



The project average GGI is expected to be in the range of 0.73 to 0.78 tCO_2-e / MWh over the life of the project, depending upon the source of coal and the quantity of natural gas consumed.

This is approximately 31% to 36% lower than the current best performing Latrobe Valley brown coal power station (Loy Yang A), with a GGI of 1.13 tCO_2-e / MWh, and is 45% to 48% lower than the Hazelwood Power Station, with a GGI of 1.40 tCO_2-e / MWh.

The GI for Niederaussem K power station (which is the highest efficiency power station operating on brown coal) is reported to be 1.0 t CO_2 / MWh net[10], and hence 0.93 t CO_2 / MWh 'as gen' assuming a 7% auxiliary demand.

---

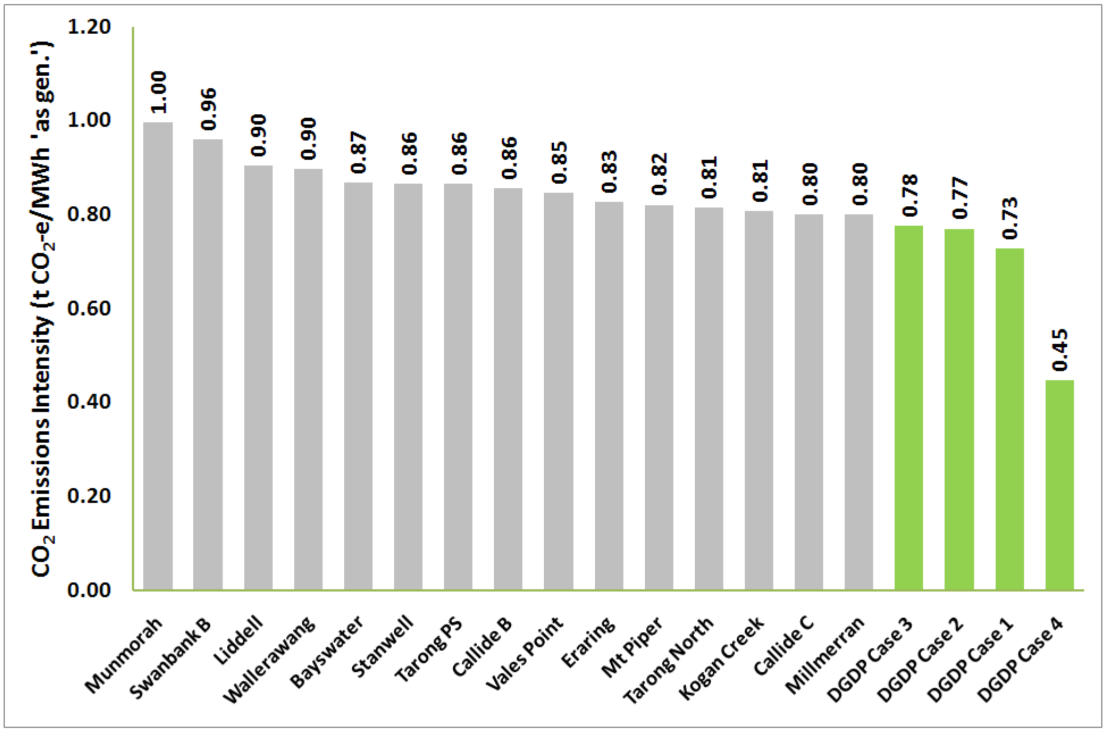
[9] The data was sourced from greenhouse intensity data on a 'sent out' basis published by each of the generators (or from other reputable sources), with assumptions made on the internal electricity consumption to convert from a 'sent out' to an 'as generated' basis.

[10] RWE Website. **http://www.rwe.com/web/cms/contentblob/2978/data/8735/DL-WTA-Technology.pdf**

4.3.2. Benchmarking against Existing Black Coal Power Stations

The calculated Scope 1 GHG emissions intensities (as generated basis) for DGDPS (Cases 1 to 4) are compared with GGIs from other (existing) black coal power generation facilities in Figure 7[9]. The four DGDP cases have GGIs lower than all the fifteen black coal power stations presented.

Figure 7 : Greenhouse Gas Intensities : DGDP vs Existing Black Coal Fired Power Stations



4.3.3. Benchmarking against Existing Gas Fired Power Stations

The Class E gas turbines to be used by DGDPS, (which have a proven track record with operation on syngas), are similar to those used by existing open cycle gas turbine (OCGT) (peaking) power plants around Australia. However, the proposed DGDPS will be operated in combined cycle mode (CCGT). CCGT with its waste heat recovery and steam cycle is more efficient than OCGT.

Table 9 shows the performance of all current gas fired power plant in Victoria. The DGDP operating on natural gas will have a greenhouse gas intensity of 0.434 t CO_2 / MWh ‘generated’[11], which is lower than all existing gas fired power plant in Victoria.

Across Australia there are a total of nine combined cycle power plants (none in Victoria). The 435 MW-rated Tallawarra Power Station in NSW is the most efficient, using F-class gas turbines with an estimated GGI of 0.34 t CO_2/MWh, assuming 1.5% used in station energy.

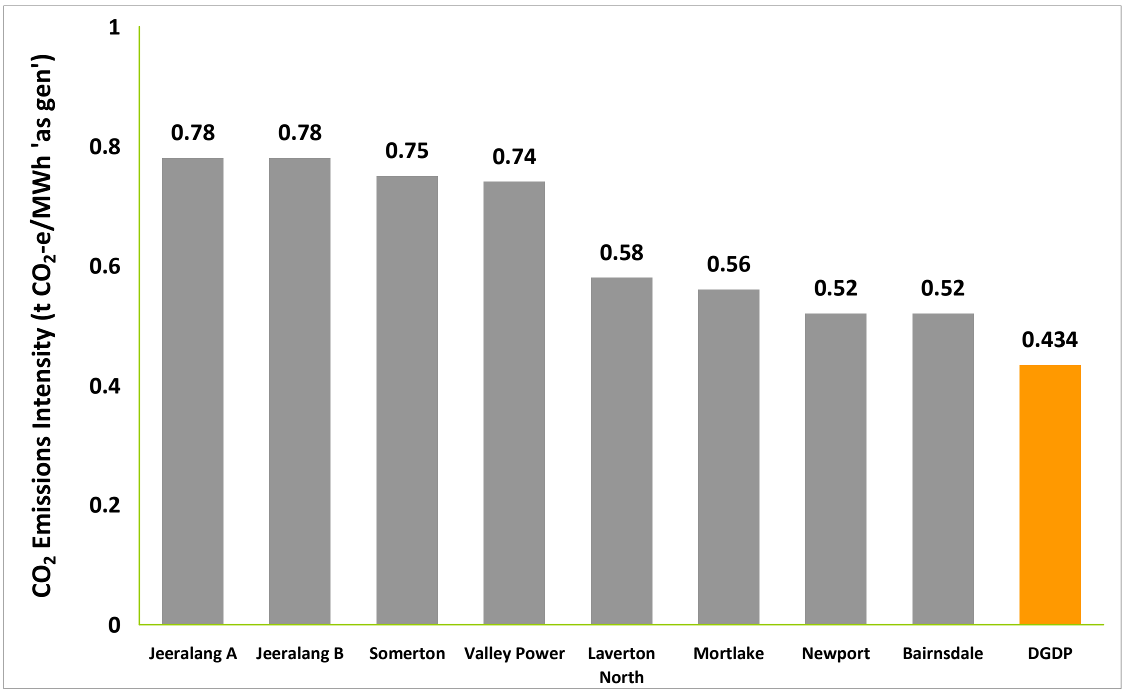
---

[11] See Table B4, Appendix B, Case 4, GIs for years 2016/17 to 2041/42 is with the use of natural gas only.

Table 10 : Existing Gas Power Plants in Victoria[12]

Plant	Type	Capacity, MW	Year	Gas Turbine	Efficiency, % HHV 'generated'	Greenhouse Gas Intensity, t CO_2-e/MWh 'generated'
Jeeralang A	OCGT	226	1979	Siemens V93.1	23.6%	0.78
Jeeralang B	OCGT	240	1980	Alstom MS-9001	23.6%	0.78
Somerton	OCGT	150	2003	GE Frame 6B	24.6%	0.75
Valley Power	OCGT	300	2002	Pratt+Whitney FT4 Twin Pac	24.7%	0.74
Laverton North	OCGT	320	2007	Siemens V94.1	31.8%	0.58
Mortlake	OCGT	550	2011	Siemens SGT5 4000F	33.0%	0.56
Newport	ST	510	1981	-	35.1%	0.52
Bairnsdale	OCGT	92	2002	GE LM6000PD	35.1%	0.52

Figure 8 : Greenhouse Gas Intensities : DGDP (on Natural Gas) vs Existing Natural Gas Fired Power Stations in Victoria



[12] Efficiency data from '2009 NTS Consultation : Final Report', NEMMCO, Issued on 14 May 2009. Greenhouse emissions data calculated from the efficiency data using the same gas properties as for the DGDP. Note that the efficiencies presented in this table are not sourced directly from the generators, and hence need to be considered as indicative only.

4.3.4. Comparison with Best Available Technologies

Generator Efficiency Standards

The Australian Greenhouse Office, Department of the Environment and Heritage, developed standards (measured in terms of greenhouse intensity), under the Generator Efficiency Standards (GES) Program, that are applicable to fossil fuel based electricity generators for Australian conditions. The standards covered both new and existing power generators, as outlined in a document entitled 'Technical Guidelines'. The Technical Guidelines were updated in conjunction with the power generation industry (taking into account technology developments) every five years, with the last version issued in 2006.

It should be noted that the Generator Efficiency Standards recognised that new plant standards for a given class of plant should reflect Best Available Technology (BAT) under a range of Australian conditions. As such allowance is given for the following :

- Power technology (including supercritical and ultra-supercritical boiler, open cycle gas turbine, combined cycle gas turbine);
- Fossil fuel type (including black coal, brown coal, fuel oil, natural gas, coal seam methane and syngas from coal gasification processes), and that standards shall not discriminate between fossil fuels;
- Fuel analysis (including moisture content, ash content, heating valve and carbon content);
- Ambient conditions (dry and wet bulb temperature and ambient air pressure);
- Load factor;
- Water availability (and selection of dry or wet cooling);
- Standards adjusted for technical and commercial factors (including cost of fuel, capital and operating cost of the power plant, electricity market requirements and constraints, and infrastructure requirements and limitations).

Supercritical Pulverised Coal Power Stations

Currently there are no supercritical pulverised coal (SCPC) fired power stations operating on brown coal in Australia. However, best practice or new plant standards were issued by the Australian Greenhouse Office (Generator Efficiency Standards (GES) 2006 Technical Guidelines) for a set of steam conditions and assuming wet cooling, as presented in Table 11. A black coal supercritical example is also provided in the table.

Table 11 : GES Technical Standards, New Plant Standards

Heading	Main Steam Pressure, MPa	Main / Reheat Steam Temp., °C	Greenhouse Gas Intensity, t CO_2-e/MWh
Brown Coal Supercritical	25.0	566 / 565	1.00
Brown Coal Supercritical	26.5	576 / 600	0.98
Black Coal Supercritical	27.5	605 / 613	0.78

The GGIs for the DGDPS cases (0.73–0.78 t CO_2-e/MWh) are significantly lower than the brown coal supercritical examples.

The GGIs for the DGDPS are on par with the AGO black coal supercritical plant new plant standards, which range from 0.72 to 0.85 t CO_2/MWh for black coal pulverised fuel (pf)-fired supercritical plant for varying ambient conditions, fuel properties and wet / dry cooling. The GGI of 0.78 t CO_2/MWh, (the example presented in Table 11), is for a 90.1 kg CO_2/GJ black coal, a dry bulb temperature of 25°C, with dry cooling and steam conditions as shown.

It is noted that Johnson (2005) reported a GGI 0.68 t CO_2/MWh for Integrated Gasification Combined Cycle (IGCC) plant with black coal.

As discussed in Section 4.2.2, HRL developed separate models to simulate the performance of an ultra-supercritical pf-fired unit with and without RWE's WTA drying technology. GIs of 0.98 and 0.88 t CO_2 / MWh respectively were calculated, which is higher than the GI calculated for the DGDP. It should also be noted that ultra-supercritical and WTA technologies have not been proven to be technically and commercially viable under fuel and ambient conditions existing in the Latrobe Valley.

Gas Turbine (Open and Combined Cycle)

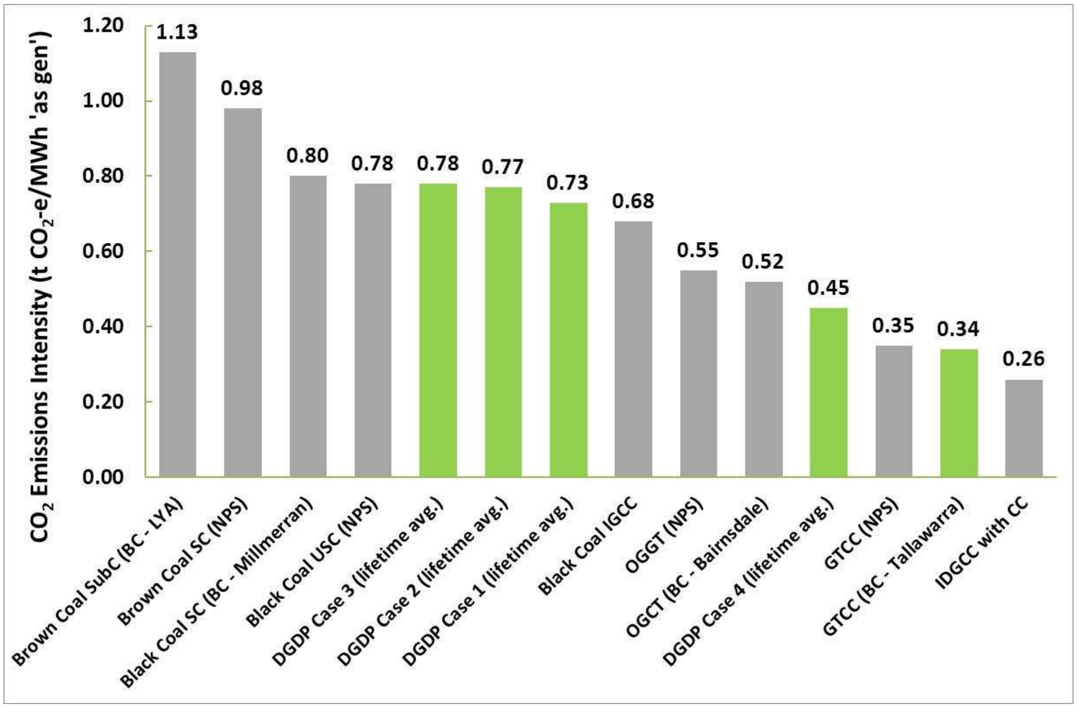
The GES Technical Guidelines provide new plant standards for natural gas fired CCGT and OCGT of 0.35 t CO_2 / MWh and 0.55 t CO_2 / MWh respectively. No standards are presented for syngas fired gas turbine operation from gasification plant.

Overall Comparison

A comparison of the DGDPS Scope 1 GGI performance results with other power generation technologies is presented in Figure 9. The acronyms expanded are: BC (Best Current); IGCC (Integrated Gasification Combined Cycle); NPS (New Plant Standards–AGO, 2006); SC (Supercritical); SubC (Subcritical); and USC (Ultra Super-Critical).

Inspection of Figure 9 indicates that, clearly, the DGDPS's IDGCC technology represents best practice with respect to the use of brown coal (noting that the operating DGDPS will always use a combination of NG and syngas).

Figure 9 : DGDP Cases compared with Other Technologies



The explanation of the data provided in Figure 9 is given below :

Table 12 : Explanation of Data Presented in Figure 9

Description in Figure	Explanation	Source
Brown Coal SubC (BC - LYA)	Brown Coal Sub Critical Best Current – LYA Power Station	LYP Sustainability Report 2008
Brown Coal SC (NPS)	Brown Coal Supercritical – AGO New Plant Standards	AGO 2006 GES Technical Guidelines
Black Coal SC (BC - Millmerran)	Black Coal Supercritical Best Current – Millmerran Power Station	J de Stephani Presentation, Intergen
Black Coal USC (NPS)	Black Coal Ultra Supercritical - AGO New Plant Standards	AGO 2006 GES Technical Guidelines
DGDP Case 3 (lifetime avg.)		HRL
DGDP Case 2 (lifetime avg.)		HRL
DGDP Case 1 (lifetime avg.)		HRL
Black Coal IGCC		Johnson, 2005
OGGT (NPS)	Open Cycle Gas Turbine - AGO New Plant Standards	AGO 2006 GES Technical Guidelines
OGCT (BC - Bairnsdale)	Open Cycle Gas Turbine Best Current – Bairnsdale Power Station	NEMMCO, 2009 NTS Consultation : Final Report
DGDP Case 4 (lifetime avg.)		HRL

Description in Figure	Explanation	Source
GTCC (NPS)	Combined Cycle Gas Turbine - AGO New Plant Standards	AGO 2006 GES Technical Guidelines
GTCC (BC - Tallawarra)	Combined Cycle Gas Turbine Best Current – Tallawarra Power Station	M Hutchison Presentation, TRUenergy
IDGCC with CC	IDGCC with Carbon Capture	HRL

4.3.5. Conclusion

The combination of the use of a high efficiency gasification and combined cycle plant, together with the use of natural gas results in the DGDP having a low greenhouse intensity compared with the current fleet of power generation in Australia and the New Plant Standards developed by the AGO. The GGI can be reduced further by adding carbon capture.

DGDP as a brown coal fired power plant has a GI of between 0.73 and 0.78 t CO_2 / MWh 'as gen'. This is at least 31% lower than the best performing Latrobe Valley brown coal fired power station (Loy Yang A), and at least 45% lower than the GI of Hazelwood Power Station. The DGDP GI is lower than the New Plant Standard (developed by the AGO) for brown coal fired supercritical thermal power stations of 0.98 t CO_2 / MWh.

The DGDP also has a lower GI than all of the current fleet of black coal power stations in Australia, and is predicted to be comparable or slightly lower than the AGO's black coal New Plant Standard.

If the power station were to be operated as a natural gas fired plant, the GI (0.434 t CO_2 / MWh) would be the lowest of all natural gas fired power stations in Victoria, which includes 5 power stations that have commenced operation in the past 10 years and Mortlake (which uses an F class OCGT which started operation this year). All but one of the natural gas fired power stations in Victoria are open cycle gas turbine power stations. The GI would be higher than the AGO's New Plant Standard for combined cycle gas turbine power plant and the best current natural gas fired power plant (Tallawarra) of 0.35 and 0.34 t CO_2 / MWh respectively but lower than the AGO's New Plant Standard for OCGT.

4.4. Sulphur Dioxide Emissions

The sulphur dioxide emissions are essentially proportional to the coal demand, and the sulphur content of the coal.

Latrobe Valley coals are amongst the lowest sulphur content coals in the world. A review of bore analysis indicates that Morwell / Driffield coal has a sulfur content between 0.22 %db[13] and 0.55 %db (average of 0.33 %db), and Yallourn North Extension coal between 0.23 %db and 1.01 %db (average of 0.46 %db).

[13] % db = percentage weight, expressed on a dry basis.

The sulphur dioxide emissions for DGDP will be significantly lower than that for existing brown coal fired generators in the Latrobe Valley due to the higher efficiency, as presented in Table 9 (due to a lower coal demand per MWh of power generation).

For the DGDP sulphur dioxide emissions are further reduced through the use of natural gas, which has a very low (almost zero) sulphur content.

As a result of the efficiency gains and the use of natural gas, the sulphur dioxide emissions rate per unit of power generation (t SO_2 / MWh) will be approximately half that of the existing Latrobe Valley brown coal fired generators.

In the context of using low sulphur content fuel, the inherent high process efficiency and the use of natural gas the proposed DGDP represents best practice for coal-based power generation with the lowest rate of SO_2 per MWh.

4.5. Carbon Monoxide Emissions

Carbon monoxide emissions from gas turbines are generally very low, in part due to the presence of large amounts of excess air in the stack gases. Conventional pulverised fuel (pf)-fired plant is often more susceptible to emission of carbon monoxide due to a requirement to minimise excess air levels (generators aim to operate at excess air levels just above the point at which CO levels start to increase dramatically with a further reduction in air supply).

Carbon monoxide emissions from a conventional gas turbine combustion system operating on Natural Gas are usually around 10 ppmvd (parts per million by volume, dry) or about 0.012 g/m^3 at steady state loads > 50%. During ignition and acceleration there will be higher transient emission levels. The CO emissions are heavily linked to the firing temperature, and as long this is maintained above a minimum value, CO emissions from gas turbines are low and are readily controlled.

There are a number of differences with the DGDP compared with a conventional GTCC plant :

- Firing temperatures will be lower on syngas due to the use of low calorific value syngas;
- Carbon monoxide emissions can increase with an increase in water or steam addition (with greater sensitivity at lower firing temperatures). Some water will be removed from the syngas using coolers to optimise combustion stability and emission performance;
- Burner design is different with the use of diffusion combustion technology with syngas, compared with dry low NOx burners used for natural gas;
- The DGDP will utilise duct burners in the HRSG.

Carbon monoxide emissions from the air heater, pre-dryer and char burner stacks are expected to be readily controlled, given good burner design and combustion control, and it is fully expected that CO emission will be significantly below SEPP Schedule E limits.

Overall, given the majority of the emissions are from the gas turbine / HRSG stack and that given the large excess of air used in the combustion process in gas turbines and the low levels used in conventional power plant, it is expected that the carbon monoxide emissions from DGDP will be significantly lower than the current fleet of brown coal fired power generators.

4.6. Nitrous Oxide Emissions

NO_X is formed in the combined cycle plant from :

- fuel NO_X from the combustion of ammonia in the syngas in the gas turbine; and
- thermal NO_X from oxidation of N_2, due to the temperature profile in the gas turbine combustor and from natural gas combustion during duct firing in the Heat Recovery Steam Generator (HRSG).

Ammonia formed in the gasifier is converted to NO_X during combustion of the syngas in the gas turbine.

The DGDP will employ technologies designed to reduce NO_X formation, including:

- scrubbing of ammonia from the syngas (with a design of 95% ammonia removal) to reduce the formation of fuel NO_X during combustion of syngas; and
- steam injection to control the formation of thermal NO_X formation when the gas turbines are operated on natural gas.

Diffusion combustion technology must be used in the gas turbine to assure combustion stability for the low calorific value syngas. As such, Dry Low NO_x burners normally employed for combustion of natural gas are unable to be used. This requires the use of steam to reduce NO_x formation when the gas turbine is operated on natural gas.

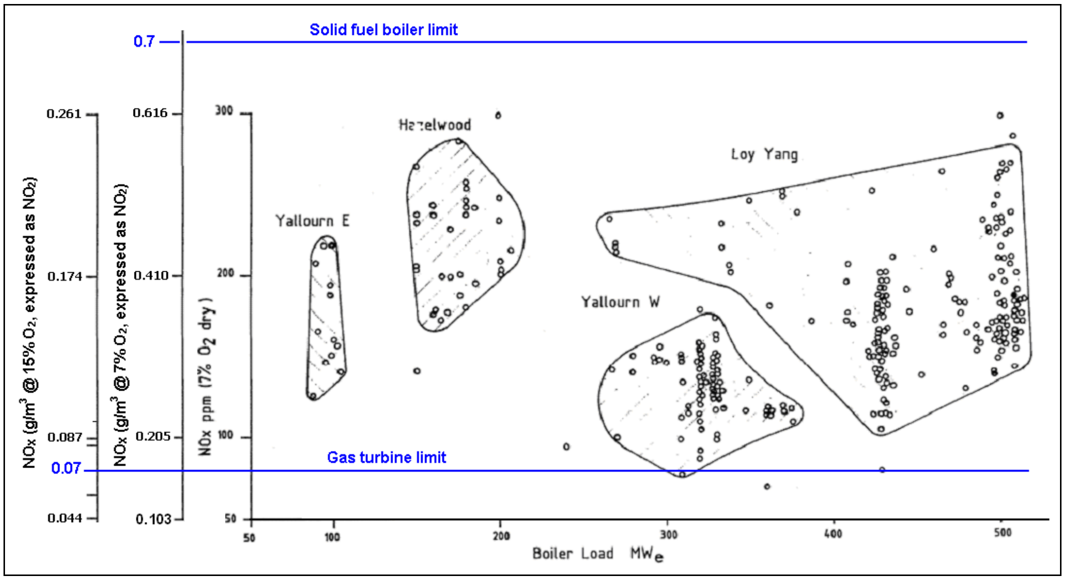
The presence of water vapour in the syngas acts to reduce NO_X formation. Due to the drying of the brown coal in the dryer, the moisture content of the syngas supplied to the gas turbine is high (although some moisture will need to be separated from the syngas to enable stable combustion in the GT).

Whilst the DGDP burns gases in gas turbines (both syngas and natural gas), it is emphasised that the main energy source is a solid fuel (brown coal). The NO_x emissions from the GTCC are to be controlled to below 0.1 g/m^3 (15%, dry, 0°C) under all operating conditions.

Figure 10 shows some historical data for NO_x emissions from three current Latrobe Valley brown coal generators (Loy Yang A, Hazelwood and Yallourn W). The figure shows that the upper limit of NO_x formation from the DGDP is lower than the average rate of formation for all these three power stations.

As a comparison the SEPP Schedule E NO_X limit for solid fuels (e.g. conventional brown coal fired power plant), is 0.7 g/m^3 (7% O_2, dry, 0°C), and the SEPP Schedule E limit for gaseous fuels in gas turbines is 0.07 g/m^3 (15% O_2, dry, 0°C). It is noted that the latter limit would normally be applied to gas turbine plant burning natural gas where Dry Low NO_X technology could be applied to further control NO_X emissions.

Figure 10: Brown Coal Fired Power Station NO_X Emissions & EPA Limits[14]



NOx Emissions from Char Burner

The char burner combusts fine dust collected from the main filter as well as milled bottom char extracted from the gasifier. The char consists of unreacted carbon and ash, as well as fine (dry) brown coal.

Combustion trials of the main filter dust were conducted in HRL's "1000 hr furnace" combustion test facility, and optimal combustion conditions for minimisation of emissions were determined.

Given the proposed DGDP design and the combustion experience of the pilot plant main filter dust, it is proposed that the relaxed Schedule E limit for power station boilers for electricity generation of rated output equal or greater than 250 MW is used as the licence limit, namely 0.78 g/m^3 (dry at 7% O_2, 0°C, 1 atm).

It should be noted that the char burner stack gas flow is only 7.6% of one of the combined cycle plant stack gas flow.

NO_x Emissions from Air Heater / Pre Dryer Stacks

The air heater and pre-dryer will use natural gas as the fuel. It is expected that the NO_X limit in Schedule E of the SEPP for natural gas fired fuel burning units should be readily attained, namely 0.35 g/m^3 (7%, dry, 0°C, 1 atm).

The air heater and pre-dryer stack gas flows are just 0.5% and 5.2% respectively of one of the combined cycle plant stack gas flow.

---

14 McIntosh, et al., 1986.

4.7. Particulate Emissions

Combined Cycle Plant Stack

Very high efficiency particulate filtration technology shall be employed for cleaning the syngas prior to combustion, using porous ceramic filters in the "main filter vessel", which is essential to avoid damage to the gas turbines. Separation efficiencies > 99.9% are achievable with this technology. The filters are graded to separate particles down to 0.3 µ.

Further protection (just prior) to the gas turbine is provided through the use of a "back up filter", which is comprised of multiple candles, similar to those used in the main filter.

It is expected that the principal components of the particulates are smoke (from the syngas or NG combustion), particulates drawn in with the combustion air to the GT (note that an air filter shall also be employed), particulates not captured in the main and back-up filters, entrained ammonium chloride / sulphate, and erosion and corrosion products.

The separation efficiency of the candle filter technology is substantially greater than that achievable using conventional technology, such as electrostatic precipitators (ESP), as is used for all of the existing Latrobe Valley brown coal fired generators.

Char Burner and Pre-Drier Stacks

High quality, high collection efficiency filter bags are proposed to be used for the DGDP for the char burner and the pre-drier stacks.

Filter bag technology is considered to be best practice technology for dust collection, with the current trend being towards greater use of this technology for larger scale plants. Particles are retained on the upstream face of the bags, while the cleaned gas is vented to atmosphere. A filter cake builds up over time, followed by a short period of reverse flow to clean the bags. The cleaning does not return the bags to its original state, and particles are deposited within the filter cloth, which helps reduce the pore size between the fibres, resulting in high efficiencies with sub-micron particles. Fabric filter collection efficiencies for < 1µ particles of > 99.6% are reported for fabric filters, compared with > 96.5% for ESPs[15], which equates to emissions from an ESP being 8.75 times that of filter bags.

The performance of ESPs for separation of fine particulate matter can be variable due to a number of reasons :

- the performance of ESPs is dependent on the resistivity of the dust, which if it is too low the particles reaching the electrode lose their charge easily and dust re-entrainment can occur. Too high a resistivity results in an insulating layer being formed on the electrode which also leads to a reduction in collection efficiency;
- the particle migration velocity is proportional to the particle diameter (independent of particle size for particles < 1µ). The separation efficiency of very fine particles can therefore be limited;

[15] Environmental Resources Management (1996), "Revision of the EC Emission Limit Values for New Large Combustion Installations (>50 MWth)". Final Report.

- rapping used to dislodge fly ash off the collecting electrodes can be re-entrained into the flue gas, reducing the separation efficiency (particularly for finer particles);
- the separation efficiency is affected by the density of the ash;
- the separation efficiency is particularly affected by the flue gas flow distribution in the ESP and the supply ducting.

None of the above are issues for bag filters.

Filter bags can suffer from holes or tears. This is readily identifiable and replacement to restore performance can be undertaken during plant outages.

Overall, due to the higher efficiency of the DGDP and the use of natural gas will mean that the quantity of ash being handled and required to be separated will be substantially lower than for the existing brown coal power stations in the Latrobe Valley. In addition, the use of candle filter and bag filter separation technologies (which have higher separation efficiencies than electrostatic precipitators), will result in even lower particulate emissions.

4.8. Water Consumption

Up to 2 GL/yr of water is expected to be required during operation of the proposed demonstration power station, allocated from the State Electricity Commission Victoria's (SECV) unused entitlement.

The DGDP is expected to use about 75% less water per GWh than the best practice (in regards to water consumption) existing brown coal fired power station in the Latrobe Valley, namely Loy Yang B power station. Loy Yang B uses 1.96 ML/GWh (LYB Power Station Environmental Performance Report 2006), compared with an expected 0.48 ML/GWh for DGDP. The average water consumption for all brown coal generators in the Latrobe Valley is 2.31 ML/GWh. The major use of water in a conventional thermal power station is in the cooling tower, used to reject waste heat from the condenser.

With the IDGCC technology, approximately two thirds of the power generation occurs in the gas turbine, which does not require water. As a result around 40% less water per GWh is expected to be the direct result of using the IDGCC technology, as it is applied to the DGDP.

A second key design selection contributing the remaining (about 35%) water saving per GWh is the use of Air Cooled Condenser (ACC) technology. ACC has been selected over a Wet Cooling System as the primary cooling technology for cooling of condensate in the steam cycle.

As the steam cycle is significantly smaller than for a conventional thermal power plant, other water losses, such as blow-down will also be lower.

4.9. Best Practice Conclusion

The DGDP has been assessed on the basis that the relevant ‘industry sector or activity’ is the brown coal fired electricity generation industry sector.

The performance of the DGDP has been assessed in regards to efficiency and carbon dioxide, sulphur dioxide, carbon monoxide, NO_x and particulate emissions as well as water consumption. The performance of the DGDP has been assessed against the current fleet of Latrobe Valley power generators and the latest New Plant Standards developed by the AGO.

The use of high efficiency gasification and combined cycle gas turbine plant results in lower brown coal consumption (and hence all emissions) per MWh of power generation than is achievable by the existing Latrobe Valley power generators. Further emission reduction is achieved through the use of natural gas in the power station. Even lower greenhouse emissions can be achieved through the implementation of carbon capture.

The DGDP efficiency is significantly higher than can be achieved using best practice ultra-supercritcal pulverised coal technology (which is yet to be used for Latrobe Valley brown coals) as outlined by the New Plant Standards developed by the AGO.

In addition to the emission reduction achieved through the efficiency gains, further reductions compared with conventional power plant are achieved through the overall DGDP design, which includes the use of high collection efficiency candle filter and bag filters (which further reduces particulate emissions), use of air cooled condensers (which reduces water consumption) and the use of gas turbine technology which reduces NO_x and CO emissions and water consumption.

The overall performance is summarised as follows :

Efficiency

- The average DGDP efficiency is 43% higher than the average efficiency of all current Latrobe Valley power generators, and is 33% higher than the efficiency of the most efficient generator, Loy Yang A;
- The average DGDP efficiency is 14% higher than the AGO’s New Plant Standard for power generation from brown coal fired power plant;

Greenhouse Emissions

- DGDP’s GI range of 0.73 to 0.78 t CO_2 / MWh is lower than the previous Victorian State Government’s proposed GI standard of 0.80 t CO_2 / MWh for new power generation;
- DGDP’s GI range is lower than the Australian Government’s election commitment made in July 2010 for a GI standard of 0.86 t CO_2 / MWh for new power generation;
- DGDP is Carbon Capture and Storage (CCS) ready, which is also a requirement outlined in the Australian Government’s July 2010 election commitment;

- DGDP's GI is at least 31% lower than the best current Latrobe Valley generator, namely Loy Yang A power station;
- DGDP's GI is lower than the AGO's New Plant Standard for brown coal fired power plant of 0.98 t CO_2 / MWh;
- DGDP's GI is lower than the best current ultra-supercritical pf fired power station operating on brown coal in the world, namely RWE's Niederaussem K power station in Germany;
- DGDP's GI is lower than that potentially achievable using ultra-supercritical pf fired power station in conjunction with RWE's WTA technology.
- The GI of DGDP when operating on natural gas is lower than all current natural gas fired power plant in Victoria, including the recently commenced Mortlake power station which uses high efficiency F class gas turbines in open cycle mode.

Sulphur Dioxide Emissions

- Due to the higher efficiency and the use of natural gas (which has essentially no sulphur in the fuel), SO_2 emissions will be about half that of the current Latrobe Valley generators per MWh of power generation.

Carbon Monoxide Emissions

- Due to the higher efficiency and the use of gas turbine technology, carbon monoxide emissions are expected to be substantially lower than that achievable by conventional pf-fired power stations, such as those used by the current Latrobe Valley generators.

Nitrous Oxide Emissions

- NO_x emissions from the gas turbine / HRSG stack are to be controlled to under 0.1 g/m^3 (15% O_2, dry, 0ºC), which is significantly lower than that achieved by the existing Latrobe Valley brown coal fired generators.

Particulate Emissions

- The quantity of ash to be handled by DGDP per MWh of power generation will be lower than the existing Latrobe Valley brown coal fired generators due to the higher efficiency, and hence lower quantity of brown coal supply to the power station per MWh of power generation;
- Particulate emissions are further reduced by the use of natural gas;
- Particulate emissions are even further reduced through the use of high efficiency candle filter and bag filter technology, which will have lower emissions than the use of electrostatic dust precipitators used by existing Latrobe Valley power generators.

Water Consumption

- The DGDP is expected to use about 75% less water per GWh than the best practice (in regards to water consumption) existing brown coal fired power station in the Latrobe Valley, namely Loy Yang B power station as a result of the use of gas turbine and air cooled condenser technology.

Having regard to the overall performance of the plant, it is the author's belief that the performance of the DGDP as a whole constitutes best practice in respect to the sector or activity of power generation from brown coal, and meets the definitions of best practice as set out in the SEPP (AQM). There are reductions in the emissions of CO_2, CO, SO_2 and particulate emissions per unit of generation when compared with existing Latrobe Valley generators. With the higher efficiency of the process, the consumption of natural resources such as coal and water per unit of power generation is also reduced. There is therefore less waste and less pollution.

Best practice performance is also achieved when comparing the performance of the DGDP with the AGO's New Plant Standards or the standards for new power generation plant proposed by State and Australian Governments.

5. CURRICULUM VITAE

Name: **Alexander Blatchford**
Current Position: **Principal Process Engineer**
Employer: **HRL Developments Pty Ltd, Unit 9, Level 1, 677 Springvale Rd, Mulgrave, Vic 3170**
Qualifications:

Bachelor of Chemical Engineering, Exeter University, 1989

Areas of Expertise:

- Gasification performance fundamentals and design;
- Process modelling and design;
- Greenhouse gas reporting and compliance.

Gasification Experience (HRL 1994 to present):

17 years expertise in coal gasification :

- Full scale IDGCC process design and cost estimation;
- Development of oxygen blown gasification process and testing at pilot scale level;
- Testing of gasification performance for specific coals at pilot scale;
- Development and verification of gasification performance models;
- Design and performance of air nozzles for gasifier;
- Physical modelling of gasifier;
- Gasifier vessel design sizing specification;
- Ash deposit mitigation strategies;
- Coal decrepitation mechanisms and mitigation strategies;
- Performance investigations for CGDU (pilot scale plant) and CGDF (development scale) gasification plants.

Greenhouse Consulting Experience (HRL 2000 to 2010):

- Management of team of specialist greenhouse consultants for the power generation industry;
- Specialising in greenhouse reporting for power stations;
- Expertise in coal weigher performance;
- Development of generation industry best practice performance guidance (prepared for the NGF) for coal weigher performance, replacement processes for data gaps, carbon in ash and coal sampling and measurement, reporting of minor fuels and definition of materiality in reporting;
- Development of technical guidelines for the creation by generators of carbon credits under the NSW Greenhouse Gas Reduction Scheme;
- Assisted in the development of the Generator Efficiency Standards for power generators in Australia, and acted as an independent assessor under the scheme.

AEA Technology, UK (1991 to 1994)

- Process engineer working as a consultant to the oil and gas industry.

6. GENERAL REFERENCES

1. AGO (2006): Published by the Australian Greenhouse Office in the Department of the Environment and Heritage, *Technical Guidelines Generator Efficiency Standards*. December 2006.
2. ALP Election Commitment Announcement, *Tough Emission Standards for New Coal Fired Power Stations,* 23 July 2010, http://www.alp.org.au/federal-government/news/tough-emissions-standards-for-new-coal-fired-power/
3. ALP (2010): Julia Gillard and Labor*, A cleaner future for power stations*. Interdepartmental Task Group Discussion Paper, Authorised N. Martin for the ALP, 5, 9 Sydney Ave. Barton ACT. http://www.ret.gov.au/energy/Documents/sustainbility-and-climate-change/MO%20Final%20InterDepartmental%20Discussion%20Paper%20Cleaner%20Future%20Power%20Station%2026%20November%202010%20EMBARGO%20til%2030%20November%20(2).pdf
4. Commonwealth of Australia, Australian Bureau of Statistics, Australian and New Zealand Standard Industrial Classification 2006 (ANZSIC), ABS cat no. 1292.0, 2006.
5. Commonwealth of Australia, *National Greenhouse and Energy Reporting (Measurement) Determination 2008 as amended* made under subsection 10 (3) of the National Greenhouse and Energy Reporting Act 2007. Compilation prepared 27 June 2009 accounting for amendments up to *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1)*.
6. Commonwealth of Australia, *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1)*, National Greenhouse and Energy Reporting Act 2007, Determination made under subsection 10 (3) of the National Greenhouse and Energy Reporting Act 2007, 23 June 2009.
7. Commonwealth of Australia, Media Release, Putting a Price on Carbon Pollution, 10 July 2010, http://ministers.treasury.gov.au/DisplayDocs.aspx?doc=pressreleases/2011/084.htm&pageID=003&min=wms&Year=&DocType=0
8. Commonwealth of Australia, Media Release, *CCS Flagship Projects Short-Listed*, Minister for Resources and Energy, 8 December 2009, http://minister.ret.gov.au/MediaCentre/MediaReleases/Pages/CCSFlagshipProjectsShort-Listed.aspx
9. DCCEE (2009c): Department of Climate Change, *National Greenhouse Accounts (NGA) Factors*, June 2009.
10. Department of Resources, Energy and Tourism, Low Emissions Technology Demonstration Fund (LETDF), http://www.ret.gov.au/energy/clean/cei/low_emissions_technology_demonstration_fund/Pages/LowEmissionsTechnologyDemonstrationFund.aspx
11. DPI (2008): Victorian Government, Department of Primary Industries, *Energy in Victoria*, *Energy Technology Innovation Strategy*. The State of Victoria, April, 2008.
12. Environmental Resources Management (1996), "Revision of the EC Emission Limit Values for New Large Combustion Installations (>50 MWth)". Final Report.

13. HRL (2005): *Prospects for Brown Coal IDGCC*, By Terry Johnson, HRL Developments Pty. Ltd., Mulgrave, Victoria, Australia. Coal 21 1st Annual Conference, Sydney, Australia, 5th-6th April 2005.
14. McIntosh M.J., Ottrey A.L. & Jeremiejczyk J.P., 1986. Low NOX emissions from boilers firing Latrobe Valley brown coal, Conference on power plants, Strasbourg, Germany, 2-6 September 1986.
15. Minister for Energy and Resources (2010): *Cleaner Energy Projects Share in up to $29 Million.* Minister for Energy & Resources, 20 January 2010.
16. NEMMCO, 2009 NTS Consultation : Final Report, 14 May 2009
17. Pall Corporation, Pall-Dia-Schumalith Data Sheet, http://www.pall.com/pdfs/Fuels-and-Chemicals/PIDIASCHUMALEN.pdf
18. SEPP (2001): Victorian Government, *STATE ENVIRONMENT PROTECTION POLICY (AIR QUALITY MANAGEMENT)*, Victoria Government Gazette, SPECIAL No. S 240, Friday 21 December 2001.
19. Victorian Government, *Protocol for Environmental Management, Greenhouse Gas Emissions and Energy Efficiency in Industry*, Publication 824, January 2002, https://epanote2.epa.vic.gov.au/EPA/Publications.nsf/2f1c2625731746aa4a256ce90001cbb5/a9c1e4da4c8b0124ca256b3c00111e13/$FILE/824.pdf
20. VG (2010): Victorian Government, *Taking Action for Victoria's Future, Victorian Climate Change White Paper - The Action Plan*, Victorian Government Department of Premier and Cabinet, Melbourne, July 2010.
21. Victorian Government, *Climate Change Act 2010*, No. 54 of 2010, September 2010

7. SOURCES OF DATA FOR COMPARISONS

1. Australian Greenhouse Office - New Plant Standards, Generator Efficiency Standards – Technical Guidelines; http://www.environment.gov.au/settlements/ges/publications/pubs/technical.pdf

2. CS Energy, Callide B and C Power Stations, NSW Government Position Paper; http://www.industry.nsw.gov.au/energy/files/sustain_greenhouse_gas_ggas_position_paper_2002.pdf

3. CS Energy, Kogan Creek Power Station, Modern Power Systems Article; http://goliath.ecnext.com/coms2/gi_0199-6180681/Kogan-Creek-enters-the-commissioning.html

4. CS Energy, Swanbank B Power Station, Swanbank B Media Background Document; http://www.csenergy.com.au/userfiles/file/100326%20Swanbank%20B%20media%20backgrounder.pdf

5. Delta Electricity, Mt Piper Power Station, 2005 Annual Report, http://www.de.com.au/Annual-Reports/Annual-Reports/default.aspx

6. Delta Electricity, Vales Pt, Wallerawang and Munmorrah Power Stations, 2007 Sustainability Report; http://www.de.com.au/Sustainability/Annual-Sustainability-Reports/default.aspx

7. Eraring Energy, Eraring Power Station, NSW Government Position Paper; http://www.industry.nsw.gov.au/energy/files/sustain_greenhouse_gas_ggas_position_paper_2002.pdf

8. Gas Turbine World, *2009 GTW Handbook*, Vol. 27, Pequot Pub., 2009.

9. Gas Turbine World, *2010 GTW Handbook*, Vol. 28, Pequot Pub., June 21, 2010.

10. IGCC - Black Coal, Paper by Terry Johnson; http://www.coal21.com.au/Media/Conference/Prospects%20for%20Brown%20Coal%20IDGCCTerryJohnson.doc

11. Intergen, Millmerran Power Station, NSW Government Position Paper; http://www.industry.nsw.gov.au/energy/files/sustain_greenhouse_gas_ggas_position_paper_2002.pdf

12. Intergen, Presentation by John de Stefani: http://www.egcfe.ewg.apec.org/publications/proceedings/EGCFE/CO2emissions_Australia_2004/presentations/stefani.pdf

13. International Power, Hazelwood Power Station, 2006 Social and Environment Report; http://www.ipplc.com.au/uploads/2010/01/2006InternationalPowerHazelwoodSocialandEnvironmentreport.pdf,

14. International Power, Loy Yang B Power Station, Loy Yang B Power Station Environmental Performance Report 2006; http://www.ipplc.com.au/uploads/2010/01/LoyYangBPowerStationPublicEnvironmentReport2006.pdf

15. Loy Yang Power, Loy Yang A Power Station, Loy Yang Power Sustainability Report 2008; http://www.loyyangpower.com.au/documents/pubrep/2008/sust06.pdf

16. Macquarie Generation, Liddell and Bayswater Power Stations, Environmental Performance; http://www.macgen.com.au/Environment/EnvironmentalPerformance.aspx

17. NEMMCO, 2009 NTS Consultation : Final Report, NEMMCO, Issued on 14 May 2009

18. Snowy Hydro, Laverton North Power Station, http://www.power-technology.com/projects/laverton/

19. Stanwell Corporation, Stanwell Power Station, Tabled Amended Statement of Corporate Intent 2008-09; http://www.stanwell.com/Files/Statement_of_Corporate_Intent_2008-09.pdf

20. Tarong Energy, Tarong North Power Station, 2008 / 2009 Annual Report; http://www.tarongenergy.com.au/Portals/0/docs/annualReports/FINAL%20Tarong%20Energy%202008%20-%202009%20Annual%20Report%20-%20WEB%20VERSION.pdf

21. Tarong Energy, Tarong Power Station, 2003 / 2004 Annual Report; http://www.tarongenergy.com.au/Portals/0/docs/annualReports/2003-2004_Annual.pdf

22. TRUenergy, Yallourn Power Station, Social and Environmental Snapshot; http://truenergy.com.au/downloads/TRU_SEsnapshot_web2009.pdf

23. TRUenergy, Tallawarra Power Station, Power-Gen Worldwide Article; http://www.powergenworldwide.com/index/display/articledisplay/356751/articles/power-engineering-international/volume-17/issue-3/features/achieving-flexible-baseload-down-under.html

24. TRUenergy, *TRUenergy Tallawarra – meeting NSW energy demand with Australia's most efficient large-scale gas generation facility.* Presentation by Michael Hutchinson (Director Operations & Construction), TRUenergy, 4th Annual Australian Gas Markets, 24th August 2009.

APPENDIX A : ANNUAL FUEL CONSUMPTION FOR FOUR POTENTIAON OPERATING SCENARIOS

Table A1 : Annual Fuel Variations for 4 Potential Future DGDPS Operating Scenarios

	Case 1		Case 2		Case 3		Case 4	
FY	Coal (kT)	NG (TJ)	Coal (kT)	NG (TJ)	Coal (kT)	NG (TJ)	Coal (kT)	NG (TJ)
2012/13	127	4,948	127	4,948	127	4,948	31	5,309
2013/14	1,050	11,482	1,050	11,482	1,050	11,482	310	13,719
2014/15	1,602	13,165	1,335	13,256	1,335	13,256	516	16,136
2015/16	2,277	13,386	1,976	12,139	1,938	12,420	431	16,786
2016/17	2,051	11,765	2,361	8,150	2,788	9,992	0	16,697
2017/18	2,180	11,408	2,565	7,325	3,019	9,384	0	16,152
2018/19	2,198	10,779	2,621	6,421	3,063	8,606	0	14,936
2019/20	2,263	11,865	2,737	7,193	3,207	9,441	0	17,444
2020/21	2,257	12,583	2,771	7,807	3,243	10,053	0	19,949
2021/22	2,257	12,443	2,771	7,668	3,243	9,908	0	20,008
2022/23	2,257	12,702	2,771	7,927	3,243	10,165	0	20,355
2023/24	2,263	12,772	2,779	7,984	3,252	10,226	0	20,530
2024/25	2,031	11,274	2,493	6,979	2,910	9,015	0	18,307
2025/26	2,257	12,769	2,771	7,994	3,243	10,228	0	20,584
2026/27	2,257	12,730	2,771	7,955	3,243	10,191	0	20,452
2027/28	2,762	12,450	3,042	10,398	3,042	10,398	0	15,997
2028/29	2,755	11,378	3,034	9,331	3,034	9,331	0	11,683
2029/30	2,755	11,263	3,034	9,217	3,034	9,217	0	11,266
2030/31	2,703	10,804	2,976	8,797	2,976	8,797	0	10,593
2031/32	2,762	11,192	3,042	9,140	3,042	9,140	0	10,925
2032/33	2,755	11,141	3,034	9,095	3,034	9,095	0	10,823
2033/34	2,755	11,001	3,034	8,955	3,034	8,955	0	10,630
2034/35	2,755	11,102	3,034	9,056	3,034	9,056	0	10,681
2035/36	2,762	11,123	3,042	9,071	3,042	9,071	0	10,675
2036/37	2,472	9,865	2,722	8,030	2,722	8,030	0	9,464
2037/38	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645
2038/39	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645
2039/40	2,762	11,004	3,042	8,952	3,042	8,952	0	10,554
2040/41	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645
2041/42	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645

APPENDIX B : DGDP GREENHOUSE GAS EMISSIONS FOR FOUR POTENTIAL OPERATING SCENARIOS

Table B1 : Case 1: MOC-YNX-MOC syngas and NG-fuelled DGDPS

Financial Year	Total Emission (kt CO_2-e)	Net sent out (GWh)	GHG Intensity (t CO_2-e / MWh 'generated')
2012/13	377.2	691	0.526
2013/14	1,617.2	2,343	0.655
2014/15	2,244.6	3,094	0.684
2015/16	2,919.5	3,815	0.715
2016/17	2,966.2	3,957	0.705
2017/18	3,096.7	4,081	0.713
2018/19	3,084.6	4,033	0.717
2019/20	3,215.1	4,242	0.711
2020/21	3,244.7	4,317	0.706
2021/22	3,237.5	4,301	0.707
2022/23	3,250.8	4,331	0.705
2023/24	3,261.5	4,347	0.705
2024/25	2,917.3	3,879	0.706
2025/26	3,254.2	4,338	0.705
2026/27	3,252.2	4,334	0.705
2027/28	3,348.0	4,200	0.741
2028/29	3,285.9	4,069	0.750
2029/30	3,280.0	4,056	0.751
2030/31	3,205.4	3,950	0.753
2031/32	3,283.8	4,055	0.751
2032/33	3,273.8	4,041	0.752
2033/34	3,266.7	4,025	0.753
2034/35	3,271.8	4,037	0.752
2035/36	3,280.3	4,047	0.752
2036/37	2,930.7	3,611	0.753
2037/38	3,271.3	4,036	0.752
2038/39	3,271.3	4,036	0.752
2039/40	3,274.2	4,033	0.753
2040/41	3,271.3	4,036	0.752
2041/42	3,271.3	4,036	0.752
Lifetime average			0.73

Table B2 : Case 2: MOC-YNX-MOC syngas and NG-fuelled DGDPS

Financial Year	Total Emission ($kt\ CO_2$-e)	Net sent out (GWh)	GHG Intensity ($t\ CO_2$-e / MWh 'generated')
2012/13	377.2	691	0.526
2013/14	1,617.2	2,343	0.652
2014/15	1,987.3	2,825	0.664
2015/16	2,560.1	3,328	0.720
2016/17	3,138.6	3,877	0.756
2017/18	3,332.0	4,037	0.770
2018/19	3,350.2	4,003	0.779
2019/20	3,523.5	4,237	0.775
2020/21	3,593.9	4,350	0.770
2021/22	3,586.7	4,334	0.772
2022/23	3,600.0	4,364	0.769
2023/24	3,611.6	4,380	0.769
2024/25	3,231.4	3,909	0.771
2025/26	3,603.4	4,372	0.769
2026/27	3,601.4	4,367	0.769
2027/28	3,518.0	4,212	0.774
2028/29	3,455.3	4,080	0.783
2029/30	3,449.5	4,067	0.784
2030/31	3,371.6	3,962	0.786
2031/32	3,453.7	4,067	0.785
2032/33	3,443.3	4,053	0.785
2033/34	3,436.1	4,037	0.786
2034/35	3,441.3	4,049	0.785
2035/36	3,450.2	4,059	0.785
2036/37	3,082.7	3,622	0.786
2037/38	3,440.8	4,047	0.785
2038/39	3,440.8	4,047	0.785
2039/40	3,444.1	4,045	0.786
2040/41	3,440.8	4,047	0.785
2041/42	3,440.8	4,047	0.785
Lifetime average			0.77

Table B3 : Case 3: MOC syngas and NG-fuelled DGDPS

Financial Year	Total Emission (kt CO_2-e)	Net sent out (GWh)	GHG Intensity (t CO_2-e / MWh 'generated')
2012/13	377.2	691	0.526
2013/14	1,617.2	2,343	0.652
2014/15	1,987.3	2,825	0.664
2015/16	2,536.9	3,326	0.714
2016/17	3,248.0	3,891	0.774
2017/18	3,443.2	4,049	0.786
2018/19	3,447.1	4,004	0.795
2019/20	3,630.8	4,242	0.791
2020/21	3,697.7	4,349	0.786
2021/22	3,690.2	4,332	0.788
2022/23	3,703.3	4,362	0.785
2023/24	3,715.2	4,378	0.785
2024/25	3,317.2	3,901	0.787
2025/26	3,706.6	4,369	0.785
2026/27	3,704.7	4,365	0.785
2027/28	3,518.0	4,212	0.774
2028/29	3,455.3	4,080	0.783
2029/30	3,449.5	4,067	0.784
2030/31	3,371.6	3,962	0.786
2031/32	3,453.7	4,067	0.785
2032/33	3,443.3	4,053	0.785
2033/34	3,436.1	4,037	0.786
2034/35	3,441.3	4,049	0.785
2035/36	3,450.2	4,059	0.785
2036/37	3,082.7	3,622	0.786
2037/38	3,440.8	4,047	0.785
2038/39	3,440.8	4,047	0.785
2039/40	3,444.1	4,045	0.786
2040/41	3,440.8	4,047	0.785
2041/42	3,440.8	4,047	0.785
Lifetime average			0.78

Table B4 : Case 4: IDGCC ‘non-success case’, mainly NG-fuelled DGDPS

Financial Year	Total Emission ($kt\ CO_2$-e)	Net sent out (GWh)	GHG Intensity ($t\ CO_2$-e / MWh ‘generated’)
2012/13	301.4	639	0.458
2013/14	1,005.1	1,876	0.516
2014/15	1,330.6	2,355	0.542
2015/16	1,279.9	2,345	0.524
2016/17	852.3	1,914	0.434
2017/18	824.5	1,851	0.434
2018/19	762.4	1,712	0.434
2019/20	890.4	1,999	0.434
2020/21	1,018.3	2,286	0.434
2021/22	1,021.3	2,293	0.434
2022/23	1,039.0	2,333	0.434
2023/24	1,047.9	2,353	0.434
2024/25	934.5	2,098	0.434
2025/26	1,050.7	2,359	0.434
2026/27	1,043.9	2,344	0.434
2027/28	816.6	1,833	0.434
2028/29	596.4	1,339	0.434
2029/30	575.1	1,291	0.434
2030/31	540.7	1,214	0.434
2031/32	557.7	1,252	0.434
2032/33	552.5	1,240	0.434
2033/34	542.6	1,218	0.434
2034/35	545.2	1,224	0.434
2035/36	544.9	1,223	0.434
2036/37	483.1	1,085	0.434
2037/38	543.4	1,220	0.434
2038/39	543.4	1,220	0.434
2039/40	538.7	1,210	0.434
2040/41	543.4	1,220	0.434
2041/42	543.4	1,220	0.434
Lifetime average			0.45