Resource Depletion Impact Assessment By Consequence Analysis

Impacts of a Natural Gas Scarcity in Australia

Shaun Rimos
B. Ch. Eng. (Hons.)
Monash University, Australia

Department of Chemical Engineering
Monash University
Australia

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SUMMARY

Sustainable management of abiotic resources is crucial for the current generation and future generations to meet their needs. When a resource runs scarce, it holds various implications and there are potential consequences for society, such as an escalation in selling price and disruption to services and product manufacturing. Different methodologies have been proposed to measure resource depletion within the framework of a Life Cycle Assessment (LCA) over the life cycle of a product, such as the Eco-Indicator 99 method and the ReCiPe method. However, as yet, there is no consensus on what should be measured that reflects the impacts of resource depletion, whether it be the loss of reserves or the increase in environmental impacts of resource extraction in the future.

To address the wide range of resource depletion impacts, this study uses the principle of substitution to measure impacts derived from replacing one resource with another when scarcity has occurred. These impacts are examined under environmental categories (e.g. changes in global warming, acidification, photochemical oxidation, particulate emissions, water withdrawal and discharge, and solid waste generation) and economic categories (capital cost penalty and change in operating cost). The proposed methodology was used to model the impacts of substitution with black coal, diesel fuel, or coal seam gas (CSG) to explore the implications of a natural gas scarcity in Australia. This was carried out both for the upstream fuel extraction and treatment and downstream consumption of the fuel. To enable a system perspective encompassing all industries in Australia, detailed data is extrapolated from major sectors of the Australian economy to provide an approximate impact assessment for Australia as a whole.

Currently, Australia has $75 billion worth of natural gas-based plant facilities, consumes 27.3 Mt of natural gas per year and spends an average operating cost of $746 per t natural gas consumed. In a natural gas scarcity, substitution to black coal or diesel will result in an increase in all environmental impact categories. In particular, for every t natural gas substituted, CO2-equivalent emissions will increase by 2 t (85% increase), freshwater withdrawal increases by 3.3 t (184% increase) and solid waste generation increases by more than 7.8 t. The previous sunk capital costs will be lost, and new capital investment worth $124 billion will be required to transition away from natural gas. Operating costs will more than double. This will have the effect of increasing the selling price of goods such as electricity, ammonia and residential heating. If the chosen alternative was CSG, this will result in a minor decrease in most environmental impacts. CSG also has a lower transfer price which lowers operating costs. All natural gas facilities can run using CSG as fuel and feedstock and no capital cost penalty is incurred by the substitution. However, large amounts of CSG water with high salt and metals content are withdrawn from beneath the surface through CSG extraction with uncertain consequences and require purification.

The substitution impact methodology is able to measure a diverse range of normalised environmental impacts and economic impacts both for upstream extraction and downstream processing across multiple sectors and integrate them all in a system wide analysis. This makes it a useful tool to study the far-reaching consequences of resource depletion at a broader level (e.g. the entire economy of a nation). It can be used to identify sectors which should have priority for the particular resource. It can examine the effects of variation in resource quality and location on extraction emissions and costs. The proposed methodology is useful for policy and decision makers to assess the impacts of a resource scarcity at a broader level or to look at the environmental and economic benefits or risks of a substitution in different countries.

DECLARATION

I hereby declare that this thesis contains no material which has been accepted for the award of any degree or diploma at any university or other equivalent institution.

To the best of my knowledge and belief, this thesis contains no material previously published or written by another person(s), except where due reference is made in the text of the thesis.

Signed:

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PUBLICATIONS AND AWARDS

- Rimos S., Hoadley A.F.A., Brennan D.J. (2012). *Consequence analysis of scarcity using impacts from resource substitution.* Procedia Engineering **49**:26-34
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NOMENCLATURE

Abbreviations

ABARES	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
ADP	Acidification potential
AES	Australian Energy Statistics
AGO	Australian Greenhouse Office
AIP	Australian Institute of Petroleum
ANZSIC	Australian and New Zealand Industrial Classification
APLNG	Australia Pacific LNG
APPEA	Australian Petroleum Production and Exploration Association
ASU	Air separation unit
AWW	Associated water withdrawal
BAT	Best Available Technique
BFW	Boiler feedwater
BREE	Bureau of Resources and Energy Economics
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CF	Characterisation factor
CML	Institute of Environmental Science, Leiden Univeristy, Netherlands
COP	Coefficient-of-performance
CSG	Coal seam gas
DCCEE	Department of Climate Change and Energy Efficiency
DEC	Department of Environment and Conservation
DSWEPC	Department of Sustainability, Environmental, Water, Population and Communities
EAR	Environmental assessment report
EC	European Commission
EDIP	Design of Industrial Products
EDR	Economic demonstrated resources
EES	Energy Efficient Strategies
EFMA	European Fertilizer Manufacturers Association
EIS	Environmental impact statement
EPA	Environment Protection Authority
EPRI	Electric Power Research Institute
EPS	Environmental Priority Strategies
ESP	Electrostatic percipitator
FC	Fixed costs
FTE	Full time employee
FWW	Freshwater withdrawal
GDP	Gross domestic product
GHG	Greenhouse gases
GWP	Global warming potential
HDPE	High-density polyethylene
HHV	Higher heating value

HP	High pressure
HTSC	High temperature shift convertor
IAI	International Aluminium Institute
IEA	International Energy Administration
IGCC	Integrated gasification and combined cycle
ILCD	International Reference Life Cycle Data System
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organisation for Standardisation
JRC	Joint Research Centre
LAC	Linde Ammonia Concept
LCA	Life cycle assessment
LCI	Life cycle inventory
LCIA	Life cycle impact assessment
LDPE	Low-density polyethylene
LLDPE	Linear low-density polyethylene
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
LTO	Light tight oil
LTSC	Low temperature shift convertor
MMEUP	Methodology for the Ecology of Energy-using Products
NEM	National Electricity Market
NETL	National Energy Technology Laboratory
NIEIR	National Institute of Economics and Industry Research
NPI	National Pollutant Inventory
NSW	New South Wales
NT	Northern Territory
NWIS	North West Interconnected System
OCGT	Open cycle gas turbine
OL	Operating labour
PCST	Pulverised coal steam turbine
PC	Production costs
PGPLR	Prospective Gas Production Land Reserve
PM	Particulate matter
PMF	particulate matter formation
PO	Payroll overheads
POP	Photochemical oxidation potential
PSA	Pressure swing adsorption
QAL	Queensland Alumina Limited
QCLNG	Queensland Curtis LNG
QLD	Queensland
RDI	Resource depletion index
SA	South Australia
SAR	Sodium adsorption ratio
SCR	Selective catalytic reduction
SETAC	Society of Environmental Toxicology and Chemistry
SMR	Steam methane reforming
ST	Steam turbine

SWD	Solid water discharge
SWG	Solid waste generation
SWIS	South West Interconnected System
TAS	Tasmania
TDS	Total dissolved solids
UNECE	United Nations Economic Commission for Europe
VIC	Victoria
VOC	Volatile organic compounds
WA	Western Australia
WECD	World Commission on Environment and Development
WHO	World Health Organisation
WTP	Willingness-to-pay

Elements and Chemicals

Al	Aluminium
Al_2O_3	Aluminium oxide
$Al(OH)_3$	Aluminium hydroxide
C	Carbon
CH_4	Methane
COS	Carbonyl suphide
C_2H_2	Ethylene
C_2H_6	Ethane
$CaSO_4$	Gypsum
Co	Cobalt
CO	Carbon monoxide
CO_2	Carbon dioxide
H	Hydrogen
H_2S	Hydrogen sulphide
O_2	Oxygen
NH_3	Ammonia
NH_4OH	Ammonium hydroxide
NH_4NO_3	Ammonium nitrate
$(NH_4)_2SO_4$	Ammonium sulphate
$NaAl(OH)_4$	Sodium aluminate
NaCN	Sodium cyanide
NaOH	Sodium hydroxide
Ni	Nickel
N_2	Nitrogen
NO_x	Nitrogen oxide
N_2O	Nitrous oxide
S	Sulphur
SO_2	Sulphur dioxide

Units, metric prefixes and other abbreviations

Units	
J	joule
L	litre
t	tonne
g	gram
W	watt
Wh	watt-hour
°C	Celsius
m	metres
atm	atmosphere

Metric prefixes		
k	kilo	10^3 (thousand)
M	mega	10^6 (million)
G	giga	10^9 (billion)
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Other abbreviations	
bcm	billion cubic metres
Nm^3	normal cubic metres[*]
n/a	not available
tcf	trillion cubic feet
US$	US dollars
A$	Australian dollars
yr	year
scf	standard cubic feet[†]
hr	hour

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[*] Gas measured at 1 atm and 0°C

[†] Gas measured at 1 atm and 70°F

Chapter 1

Introduction: Natural Gas in Australia

1.1. FOSSIL FUEL RESOURCES AND THEIR DEPLETION

Resources are vital for the growth of human society and the economy, both for the current generation and the future generations. One concept that is gaining popularity is that future generations are entitled to the same natural resources and environment that we, the present generation, are exploiting, and our usage of resources to meet our needs must not compromise the ability of future generations to meet theirs. This concept is termed ‘sustainable development’ and was introduced in the United Nations World Commission on Environment and Development (WECD) report titled “Our Common Future” (Brundtland 1987). We take in resources from the environment to generate products and services for the purpose of improving our wellbeing, and we generate waste and emissions after using these products or services, which will impact the ecosystem. Resources are also crucial to the survival and growth of the global economy and industrial production. Thus, there are economic and social aspects of resource depletion. A sustainability assessment of resources and their current usage should include environmental, economic and social perspectives.

This study focuses on fossil energy resources and their depletion. Fossil energy resources are available in limited quantities, varying concentrations and uneven geographic distribution. They are highly valued for their chemical and energy content. When combusted, they provide heat energy and are transformed into less useful forms (e.g. CO_2). Fossil fuels such as oil and gas can also be converted into higher value products through fractionation and chemical reactions. In particular, fossil fuels are the main source of transportation fuel which plays an integral part in keeping the global economy growing. Depletion of fossil fuel resources will have major impacts on local and global economies, which have thus far been relying on affordable and accessible resources. There are situations where a perceived abundance of resources will encourage consumption or usage at an accelerated pace. An example is the post-1967 “dash for gas” in the U.K. which eventually led to a decline in natural gas resources in 2004, turning it from a net exporter into a net importer (Hammond 2000, IEA 2010).

Fossil fuel depletion and its impacts are typically represented using resource depletion indicators. The Life Cycle Assessment (LCA) methodology is a systemic approach that includes resource depletion as part of a comprehensive environmental assessment. Many methodologies for resource depletion have been proposed, but there is still a lack of consensus on the impacts of resource depletion in the Life Cycle Impact Assessment (LCIA) methodology (Heijungs et al. 1997, Lindeijer et al. 2002, Finnveden et al. 2009, Hauschild et al. 2013). In particular, the environmental problem with the extraction of abiotic resource can either be the depletion of the reserve, the loss of use options for future generations, or the increase in environmental impacts of mining or extraction in the future because the easily accessible resources are depleted first (Heijungs et al. 1997). Each different perception of the resource depletion problem will produce a wide array of characterisation methods. Some focus on the material resource aspects (e.g. CML 2002 method), while some focus on the future energy or cost penalty of extraction (e.g. ReCiPe 2008 method). A resource depletion indicator will need to reflect not only the availability of the resource in the natural environment, but also the impacts of depleting the resource. There is a need to consolidate the different perspectives together under an integrated resource depletion methodology.

1.2. NATURAL GAS IN AUSTRALIA

Natural gas has key benefits as a fuel for industrial, commercial and domestic uses, including use as a transport fuel. It is a cleaner burning energy source compared to coal and oil products due to its low sulphur and nitrogen content and its more complete combustion. Natural gas consuming plants are relatively low cost as there is no need for on-site fuel storage because of a constant reliable pipeline supply). They require fewer emissions controls and they do not need many handling stages (e.g. compared to coal-based process plants which require feed preparation and extensive effluent treatment equipment). This makes natural gas a key strategic fuel for electric power generation, offering lower capital expenditures, shorter construction times, greater flexibility in meeting peak demand, lower carbon emissions and higher thermal efficiencies relative to other substitute fossil fuels (Leather et al. 2013). Gas-fired electricity generation can also serve to complement renewable energy sources, and to help to overcome the intermittency problems associated with renewable energy sources such as solar and wind (2012b). Another key feature of natural gas is its versatility and simplicity when it comes to the number of conversion steps required for natural gas based process. Natural gas offers immediate application for a diverse pathway of usages (e.g. combustion for heating, steam reforming for hydrogen production); while coal- and oil-based processes are often complex requiring more processing steps than natural gas. Natural gas is a useful chemical reactant because natural gas has the highest H/C ratio of all the fossil fuels. Many process plants take advantage of the versatility of natural gas by using it as both a fuel and a feedstock.

Natural gas is currently the third largest global energy source and its importance is gaining prominence. Through liquefaction, natural gas can be exported to global markets to help nations fuel their economic growth and reduce their carbon intensity by deleveraging from a strong reliance on coal. Some claim that natural gas is the only hydrocarbon source of energy that could lead to a reduction in global carbon dioxide emissions at a manageable cost (Economides & Wood 2009).

The first natural gas discovery in Australia was in the township of Roma, Queensland in 1900. The gas was used to light the street lamps of Roma instead of using town gas derived from coal for a short period (The Australian Pipeliner 2005). Australia’s first commercial gas project began with a gas-fired generator in Roma in 1961. Natural gas was later found in the Cooper Basin, South Australia in 1963, in the Bass Strait, Victoria in 1965 and at Dongara, Western Australia in 1966 (The Australian Pipeliner 2005). Brisbane became the first capital city in Australia to receive natural gas supply. Gas was supplied through the Roma-Brisbane pipeline which was opened on March 17 1969 (Wilkinson 2014) (The Australian Pipeliner 2005). The first large scale offshore natural gas production from the Bass Strait near Gippsland, Victoria began in April 1969 (Wilkinson 2014). The gas was transported from the offshore fields to an onshore treatment plant at Longford and treated to produce sales gas, stabilised crude oil and an intermediate mixture of ethane, propane and butane. The sales gas was piped to Dandenong for distribution across Victoria, while the stabilised crude oil was piped from Longford to Westernport for shipping and to refineries at Altona and Geelong. The intermediate petroleum liquids mixture was piped to Westernport where a fractionation plant separates ethane from liquid petroleum gases (LPG). The ethane was piped to Altona for use as petrochemical feedstock, while propane and butane were transported to local and overseas market by ship. In 1971, extensive gas fields were discovered off the north-west coast of Western Australia and by 1989, gas was being produced in Western Australia and exported as liquefied natural gas (LNG) (Brennan 1990). Coal seam gas (CSG) in Australia was first produced in 1988 from the Pleasant Hills field in Roma.

Australia’s natural gas market has grown into three geographically and economically distinct domestic gas markets: the Eastern gas market which covers Queensland (QLD), New South Wales (NSW), Victoria (VIC), South Australia (SA) and Tasmania (TAS), the Western gas market which includes the North-West Shelf and the demand centres in Western Australia (WA), and the Northern gas market in the Northern Territory (NT). These markets are separated because of the geographical location of gas reserves, which reflects the vast distance between the main consumption centres as shown in Figure 1.1. Most of the markets (90%) are based on stable long term gas contract prices and the remaining markets trade at the spot level in the Eastern market. The Eastern gas market is characterised by an extensive pipeline system, extending all the way from Gladstone, Queensland in the north to Hobart, Tasmania in the south.

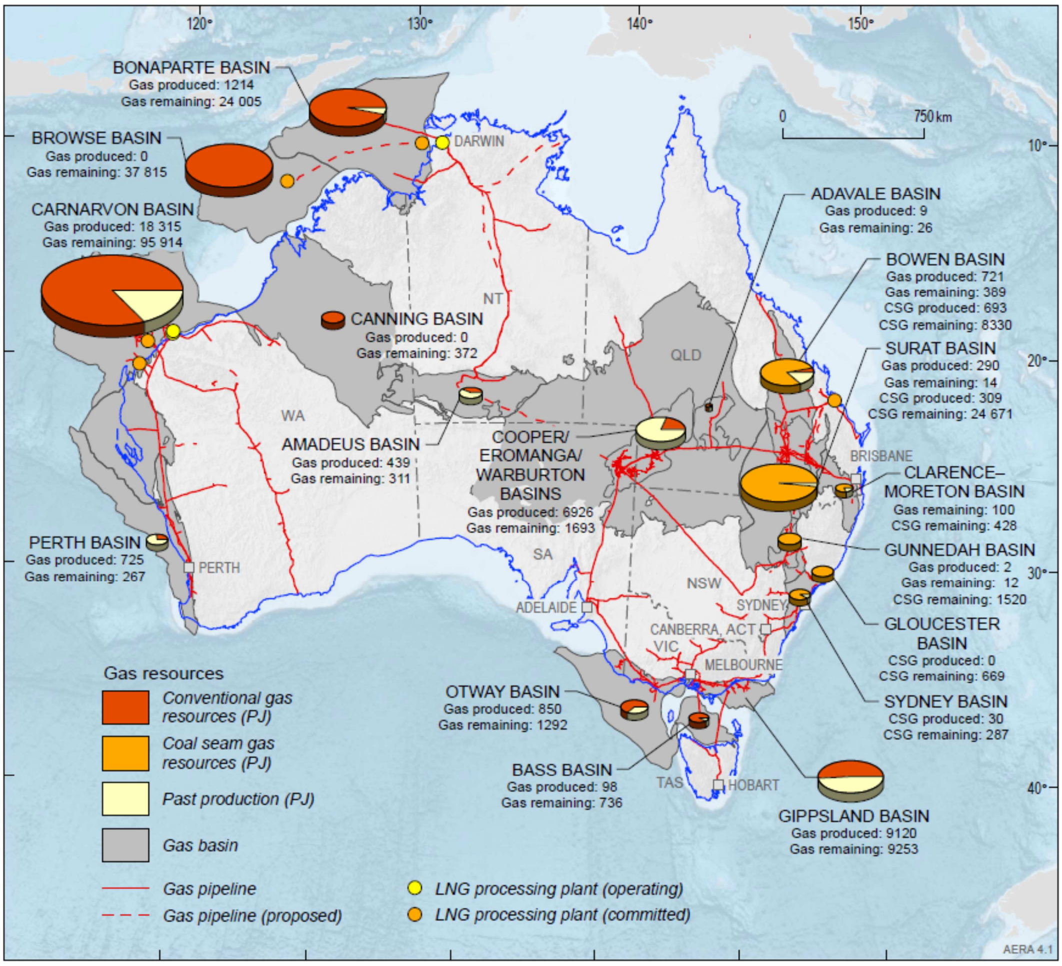

Figure 1.1: Australia’s conventional gas and coal seam gas (CSG) resources and gas-related infrastructure (2014)

Figure 1.2 shows the sources of gas (including conventional natural gas and CSG) and the upstream and downstream processes that make up Australia’s gas network. It can be seen that natural gas is consumed in almost all economic sectors in Australia. Figure 1.3 presents the breakdown of gas consumption in each sector. Out of all the sectors, the manufacturing sector was Australia’s largest consumer of gas, followed by the grid electricity generation[‡], mining and residential sectors.

[‡] The distinction is made between grid electricity generation, which is represented by the ‘Electricity’ sector in most Australian publications, and non-grid electricity generation, which mainly falls under the ‘Mining’ sector.

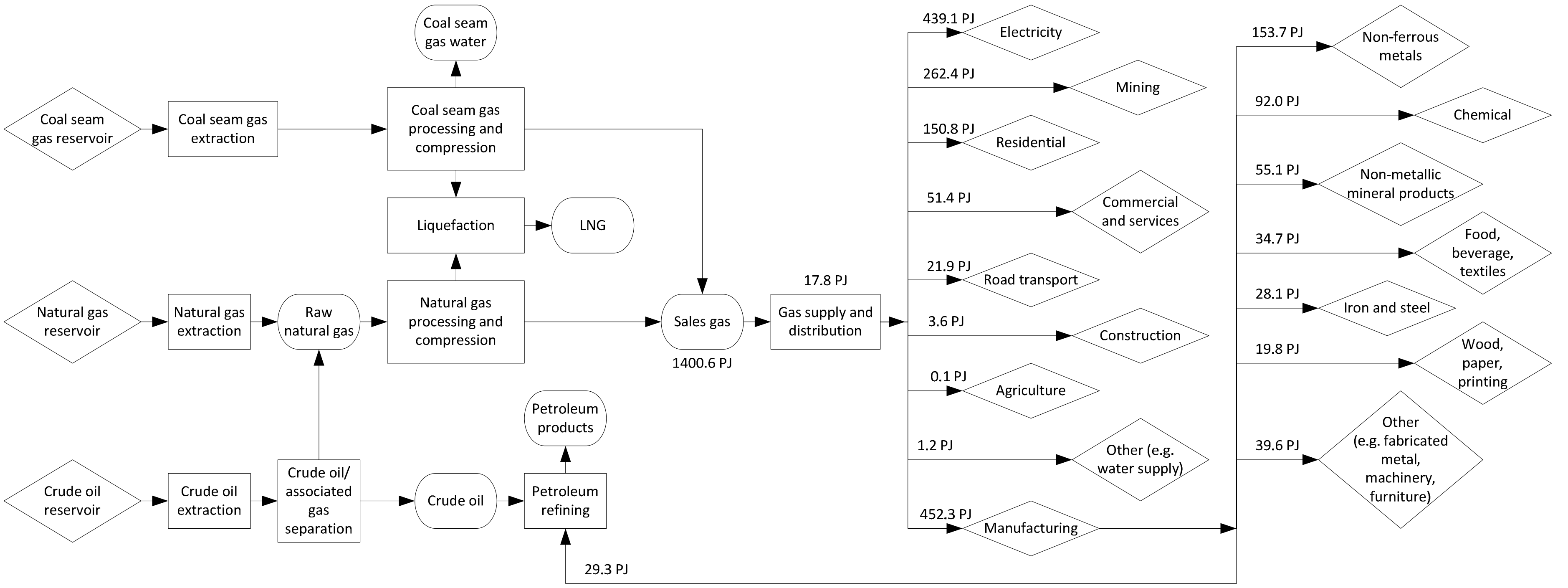

Figure 1.2: Australia's gas network which include gas sources and the upstream and downstream processes.

Note: Sectoral annual gas consumption values in petajoules (PJ) are adapted from BREE (2013a). No distinction is made between natural gas and CSG. The energy flows in this diagram are presented in more detail in Chapter 5.3.

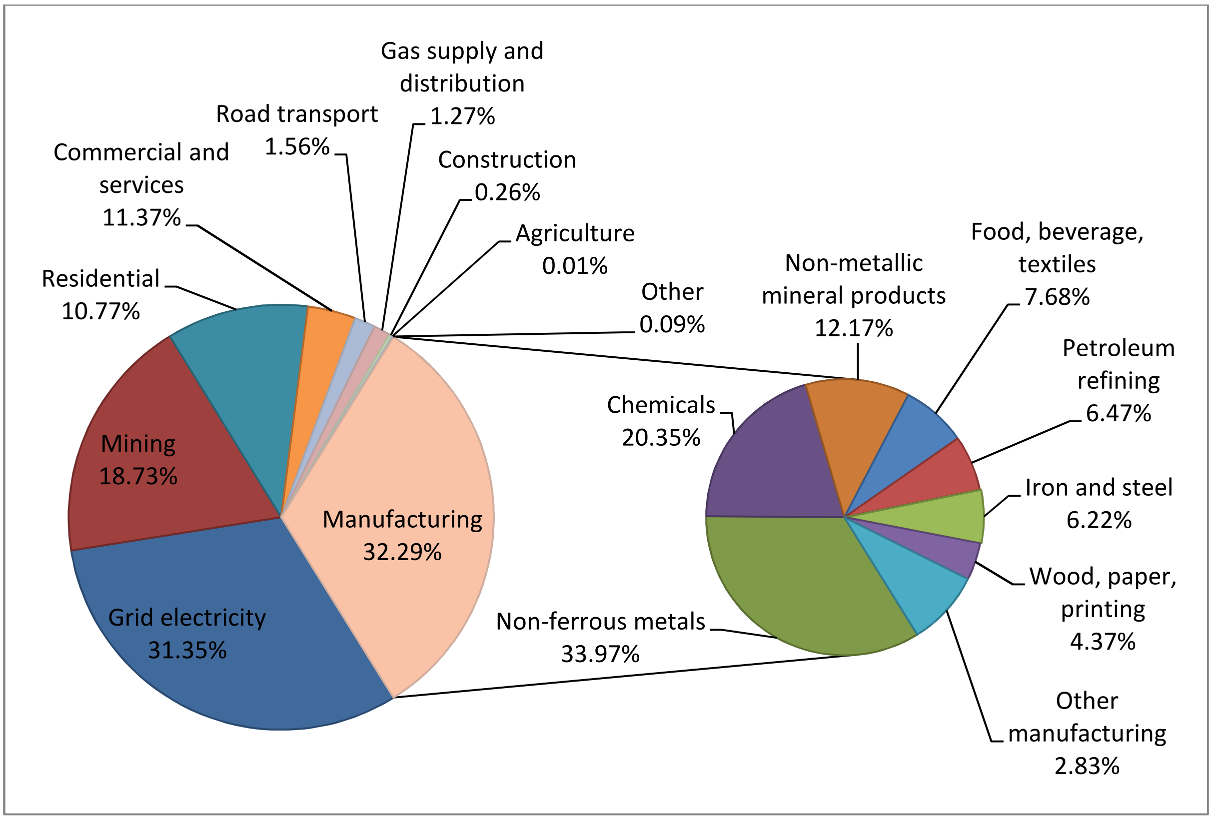

Figure 1.3: Percentage breakdown of 2012 Australian natural gas usage in Australia adapted from BREE (2013a). Note: The left plot represents the total natural gas usage while the right subplot breaks down the manufacturing sector (percentages are based on natural gas usage in the manufacturing sector only).
Note: The 'Mining' sector includes gas use by LNG plants in the liquefaction process.

Gas is widely used in the manufacturing sector as a fuel source and is crucial to a relatively small number of large consumers in the mineral processing industries (Wilcock et al. 2013). Gas is both a major energy source and a feedstock for the chemical industry. In Western Australia, the Kwinana Industrial Area is a major industrial processing centre which includes the BP petroleum refinery, a chlor-alkali plant, ammonia and fertiliser plants and a sodium cyanide plant, all of which consume natural gas as fuel or as a feedstock. Natural gas is a key feedstock in the production of ammonia (NH_3), which is used to produce NH_3-based fertilisers and ammonium nitrate (NH_4NO_3) which is used to make explosives for mining. Natural gas is also used to manufacture sodium cyanide (NaCN) which is a key reagent used in gold extraction. Ethane is also extracted from wellhead natural gas and used to produce ethylene, which in turn is processed to produce polyethylene. Altona, Victoria and Botany, New South Wales both house petrochemical complexes which produce ethylene, low-density polyethylene (LDPE), linear low-density polyethylene (LLDPE) and high-density polyethylene (HDPE) from ethane feedstock. Australia has only one methanol plant in Laverton, Victoria, that produces methanol from natural gas. Aside from exporting natural gas as LNG, the manufacturing industry presents the opportunity to add value to natural gas by producing chemicals or to use natural gas in manufacturing operations to create a diverse range of products, which can then be used within Australia or exported overseas.

A major primary use of natural gas in Australia is in gas-fired electricity generation. The relatively large share of gas consumption in the grid electricity generation sector has been mostly due to the increase in open cycle gas turbine generation capacity to meet increasing peak demand (Wilcock et al. 2013).

The mining and minerals processing sectors are major natural gas users, both of which are important to Australia's economic growth. The mining sector uses natural gas for off-grid electricity and heating. The mining sector also consumes a large amount of gas in the process of producing LNG, largely due to gas being used as an energy source in the liquefaction process (2012b).

Natural gas is also used heavily in the residential sector. The residential sector is characterised by a large number of small demand customers. The major residential uses of gas include water heating, space heating and cooking (2012b). Natural gas is more important in the southern states of Australia, such as Victoria and Tasmania, which have a colder climate and greater heating requirements compared to the other states.

It can be seen that the usage of natural gas is well-established in many residential, commercial and industrial sectors in Australia, supported by an extensive pipeline system connecting demand centres to natural gas supplies.

1.3. RECENT DEVELOPMENTS WITH NATURAL GAS IN AUSTRALIA

APPEA (Australian Petroleum Production and Exploration Association) has maintained that Australia's large reserves of clean, natural gas are crucial to meet the nation's energy needs while reducing greenhouse gas emissions and maintaining economic wellbeing (March 11, 2008). Gas, both conventional and unconventional, is Australia's third largest energy resource (2,200 PJ) after coal (9,767 PJ) and uranium (955,360 PJ) (2014). The significant gas resource base has been deemed capable of meeting increasing domestic and export demand up to the year 2050 when production will reach 8,595 PJ (2012a). Much of this projected increase was attributed to LNG projects, which required a total capacity of 90.2 Mt/yr (approximately 4,360 PJ/yr) for natural gas and 51.7 Mt/yr (approximately 2,650 PJ/yr) for CSG (Leather et al. 2013). Australia was ranked fourth among the world's LNG exporters in 2010 (2012b, Leather et al. 2013) but it aims to increase its capacity to become the world's largest LNG exporter, providing around 20% of global LNG supplies (Cronshaw et al. 2013).

Major changes have emerged in Australia's domestic and export gas industry and markets due to the rapid growth of LNG developments. One of the implications of this is the conflict of natural gas being sold to the international market or reserved for domestic customers. New gas resources are produced at higher costs than historical fields and large export projects have introduced new competition for gas in domestic markets, putting pressure on supply and price (Cronshaw et al. 2013, Wilcock et al. 2013). On the other hand, these changes were expected to bring economic benefit to Australia, notably through higher national income, more extensive gas infrastructure and enhanced regional development (Wilcock et al. 2013). As a result of the competition for gas, domestic gas consumption was projected to grow at a slow rate due to higher gas prices and lower demand growth for grid-based electricity (Cronshaw et al. 2013).

In Western Australia, gas prices began to rise in 2007 reflecting the combination of tight supply, higher cost of developing new gas and the demand competition from LNG exports (Wilcock et al. 2013). New gas developments in Western Australia tend to be in deeper waters and in general more costly to develop than historical supplies. As a result, the prices in new contracts are in the range of \$5.50 to \$9/GJ (Wilcock et al. 2013). The Eastern Australian gas market had previously been unexposed to international markets with long term prices in the range of \$2 to \$3/GJ (Cronshaw et al. 2013). Traditional gas supplies are complemented by gas from coal seams, contributing to the development of a major LNG export industry in Queensland. Many of the domestic long term wholesale contracts are nearing completion. Although supplies have increased, the additional demand competition from LNG exports will cause a tightening in the gas market and prices to reach netback levels[§] (\$6 to \$9+/GJ).

In Western Australia, gas power stations have been mothballed (e.g. Stanwell E power station in Western Australia) and coal power stations are being resurrected (e.g. Tarong coal power station in Queensland) (Australian February 6, 2014). Manufacturing Australia (2013b) reported that major companies were under pressure to move their manufacturing offshore due to the rising cost of gas, which would result in a decrease in GDP of about \$29 billion and a loss of 194,000 direct jobs . In Victoria, household gas bills were predicted to increase significantly, which would result in an increased preference for electrical appliances running on electricity generated from brown coal over gas appliances (Age September 3 2014). This indicates that not only will the lack of access to cheap gas threaten Australia’s environment and economic wellbeing, but it will also have far-reaching consequences for the environment and domestic sectors including the manufacturing and residential sectors.

Such scenarios involving high natural gas prices make natural gas less affordable, causing demand to drop and forcing users to adapt and compensate. These consequences are symptomatic of a natural gas scarcity, of which one main cause is the depletion of natural gas resources. Fleay (2007) describes how the Australian petroleum industries and government promote visions of vast quantities of cheap natural gas that should be rapidly developed and sold off. This was reminiscent to a “Magic Pudding” mentality, similar to Norman Linday’s story about a “magic pudding” that never ran out as it was eaten. Such a mentality will accelerate natural gas depletion with little regard for the consequences. Rapid depletion of natural gas resources, aging conventional gas fields, and challenges faced during the exploration and extraction of natural gas cast concern over Australia’s actual recoverable gas reserve base and ability to provide gas for use in the near future.

In response to rising prices and concerns of domestic supply shortages, WA established a formal gas reservation policy in 2006[**]. Queensland considered a similar conventional gas reservation policy in 2009 but instead approved the Prospective Gas Production Land Reserve (PGPLR) policy[††]. Some studies suggest that it is in the national interest for the government to restrict LNG exports in order to ensure that gas remains available on the domestic market at prices that the domestic users regard as

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[§] The LNG netback price is the theoretical maximum price an LNG producer would be prepared to pay for gas, or the price at which there is no difference between selling gas for LNG production and selling gas to the domestic market. It is calculated as the LNG sale price, less the costs incurred in producing and transporting the LNG to the point of sale. (Wilcock et al. 2013)

[**] Under this policy, each prospective LNG project needs to secure up to 15% of production for the domestic market as a condition of access to WA land for the location of processing facilities. (Haylen & Montoya 2013)

[††] Under this policy, the Queensland Government has the ability to impose conditions on exploration licenses which would require all gas produced from any subsequent production tenures be supplied domestically. As of now, no gas field has been set aside strictly for domestic supply and the three major LNG projects in Gladstone have been approved to proceed without any conditions or domestic supply arrangements. (Haylen & Montoya 2013)

viable for the continuation of their operations (AEC Group 2012, NIEIR 2012, ACIL Allen Consulting 2014). On the other hand, other studies conclude that if gas can be exported in the form of LNG at prices that exceed those that domestic users pay, then the national interest is best served by allowing LNG exports despite having detrimental consequences for domestic gas users (Richard Lewis et al. 2008, 2013a, BREE 2013d, Wood & Carter 2013, ACIL Allen Consulting 2014).

There is a need for a gas resource management plan to manage the various outcomes of the present day natural gas development in Australia, with respect for both the domestic gas needs and the economic opportunities from LNG exports. A suitable methodology and indicator that measures the impacts of natural gas scarcity will be a vital component in the assessment of natural gas usage in Australia.

1.4. AIM

This study aims to formulate a different and complementary resource depletion methodology that uses the concept of substitution with available alternatives (e.g. unconventional resources) due to resource scarcity. The methodology aims to capture a wide range of consequences of resource depletion ranging from emissions to air to water-related impacts and solid waste impacts. The methodology also aims to study the effect of resource scarcity on a wider economic scale and show the inter-relation between different economic sectors. Australia’s natural gas situation is used as a case study to examine the environmental and economic impacts of a natural gas scarcity and subsequent substitution of natural gas with black coal, CSG and diesel. The environmental and economic impacts act as indicators to assist the decision as to which sectors should have the priority to substitute with alternatives, and which sectors have the priority to use the remaining gas resources.

1.5. THESIS OUTLINE

Chapter 2 will cover a literature review on existing resource depletion methodologies and highlights the need for a proposed methodology that captures the full impacts of resource depletion. Chapter 3 introduces the new methodology by deriving the substitution impact indicators. A preliminary demonstration of the methodology is performed by analysing greenhouse gas impacts of natural gas substitution with black coal in electricity generation and hydrogen production due to scarcity. Chapter 4 describes the data collection methodology in detail and presents the results for grid electricity, mining, ammonia production, alumina refining and nickel refining and residential heating sectors. Chapter 5.1 features the system-wide analysis which covers all sectors from Chapter 4 to represent the whole Australian natural gas network and the impacts of scarcity. Chapter 5.1 also discusses the various implications of natural gas scarcity and substitution with alternatives in Australia to the environment, economy and society. In Chapter 6, the methodology is reviewed and discusses its strengths, limitations and opportunities for improvement.

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Chapter 2

Literature Review

2.1. OVERVIEW

This chapter aims to identify the challenges of representing fossil fuel depletion using existing methodologies and indicators. The chapter first covers resource depletion theories and perspectives, including the peak theory and its implication for fossil fuel depletion. This leads to the summary of the resource depletion indicators within and outside the Life Cycle Assessment (LCA) methodology and their limitations. The chapter then identifies the research gap in the field of resource depletion impact assessment and presents a new methodology to address this issue.

2.2. CLASSIFICATION OF RESOURCES

One challenge for resource depletion indicators is the categorisation of different resource types. Lindeijer et al. (2002) outlines the different classification methods for natural resources. The widely used method, especially in LCA divides natural resources into abiotic resources and biotic resources. Alternatively, more emphasis can be placed on the resources' capabilities of renewal and regrowth by dividing them into stock resources, fund resources or flow resources. A summary of the different classifications is summarised in Table 2.1. Fossil fuel resources fall under the category of abiotic resources and stock resources. Water and land use impacts are generally not classified under abiotic or biotic resources but under separate categories of their own (Klinglmair et al. 2014).

Table 2.1: Classification of resources according to Lindeijer et al. (2002)

Resource type	Definition
Abiotic	• Inorganic or non-living materials at the moment of extraction • Regeneration rates may appear too slow to be completely replenished within a single human lifespan
Biotic	• Living before and up to the moment of extraction from the natural environment • Can regenerate by themselves
Stock	• Finite, fixed amount in the natural environment with no possibility of regrowth, or renewal rates are on timescales much larger than the human rate of consumption
Fund	• Depletion rate is a ratio of extraction to regrowth, thus depletion rate can be hastened, reduced or reversed depending on the renewal rate
Flow	• Renewability is practically instantaneous and cannot be depleted

2.3. RESOURCE DEPLETION

One viewpoint of resources is that a resource is limited to the physical stock in the earth's crust and will deplete due to mining and extraction activities (Tilton & Lagos 2007). As these activities continue and increase in numbers and in intensity, the resource will eventually diminish and reach scarcity. This places emphasis on the quantity or physical availability of the resource in nature.

Another viewpoint is that resources are stocks in the economy in a form that can be used for human activities. Resource extraction serves to add resources to the stock in the economy, and resources are taken out by use and disposal in economic activities. Resources will only be depleted if the resource is dissipated and cannot be restored to the stock in the economy through activities such as reuse and recycling. However, fossil energy resources are generally dissipated after use (Stewart & Weidema

2005). Hence, the resource will eventually diminish and reach scarcity when the rate of extraction cannot keep up with the rate of dissipation.

Furthermore, some resources can be of lower quality, be located in more remote regions or be more difficult to process. This turns the issue of resource depletion into an economic problem. Costs and prices dictate the manner in which the resources are extracted: the least cost option or the higher grade option is first exploited until it is no longer available or economical to extract further, then the next deposit will be of lower grade, more remote, and more difficult to process. This will not only result in higher extraction and processing costs, more energy will also be required, which in turn will result in an increase in emissions and waste.

Stewart & Weidema (2005) claim that the concern is not the depletion of the resource itself, but the functionality provided by the resource. The challenge then lies in finding a substitute that not only replaces the functionality, but one with similar if not less environmental and economic impacts.

With the physical stock viewpoint, any form of mining and extraction of the resource will cause the resource to be depleted. Resource depletion can thus be mitigated by measures which minimise the rate of extraction (e.g. reuse or recycling of aluminium reduces the amount of raw bauxite mined) or increase the efficiency of extraction (e.g. enhanced oil recovery using methods such as injecting CO_2 or LPG into the reservoir).

With the economic inventory viewpoint, resource depletion can be offset by restoring the functionalities that the resources provide (Stewart & Weidema 2005). This will include reuse and recycling of resources so that the working inventory is replenished. Additionally, substitution of resources allows for different resources to replace the functionality that the original resource once provided. However, this is limited by the uniqueness of the resource and the functionality it provides. For instance, oil has the highest energy density of any fossil fuel and hence cannot easily be substituted (Hammond 2000, Brown et al. 2014).

Resource depletion can be mitigated by a number of factors, including the discovery of new deposits, capital-resource substitution (i.e. capital accumulation by an economy to offset resource depletion) and technological advances in resource extraction and purification and commodity production (Krautkraemer 1998). Many of these mitigation measures depend on economic drivers. Tilton and Lagos (2007) recommended an opportunity-cost approach to assess the effects of depletion and availability. This approach uses real commodity prices as a measure that reflects what society is willing to sacrifice to extract more of the same resource. Depleted reserves can virtually be extended by real higher prices, which will lead to technological development that would allow more effective extraction of the resource or profitable access to lower grade resources (Prior et al. 2007).

2.4. SCARCITY, PEAKING AND SUBSTITUTION

Scarcity is an extremely complex phenomenon that is determined by many biophysical, technological and social variables (Cleveland 1993). Klinglmair (2014) makes the distinction between depletion, which refers to consumption related to the physical inventory (e.g. geological/natural reserves), and scarcity, which is related to the economic availability of the resource. Scarcity is when the resource becomes virtually unavailable for use and cannot be replenished by the same resource either due to physical and economic limitations. Among the possible ramifications of scarcity include an escalation in selling price and ultimately disruption to services and product manufacturing.

One phenomenon which has consistently preceded an occurrence of resource scarcity is the "peaking" of the resource. In 1956, oil geologist M.K. Hubbert showed evidence for peak oil by predicting that conventional oil production from the mainland 48 states in the U.S. will peak by 1970 and then enter terminal decline. This was closely matched with actual peak production in 1971. The "peaking" of oil occurs at the point where half of the oil resources have been discovered and new discoveries are unable to keep up with continued production, leading to a decline in available resources. Another description will be 'the time when all of the cheapest oil has been extracted and prices rise' (Hirsch et al. 2005, Chapman 2014). The peak theory has since been applied to minerals (Prior et al. 2007, Valero & Valero 2010) and even water (Gleick & Palaniappan 2010). Several authors have presented evidence that the peak of regular conventional oil has passed and we are now in the age of declining conventional oil resources (Owen et al. 2010, Campbell 2012).

Gas has also shown signs of peak productions. For example, the development of North Sea oil in 1967 has led U.K. to undergo a sharp transition from town gas to natural gas and to become self-sufficient in oil supplies by 1981 (Hammond 2000). However, North Sea oil and gas production had declined since its peak in 2000 and U.K. became a net importer of natural gas in 2004 and a net importer of oil in 2006 (IEA 2010). This is shown in Figure 2.1.

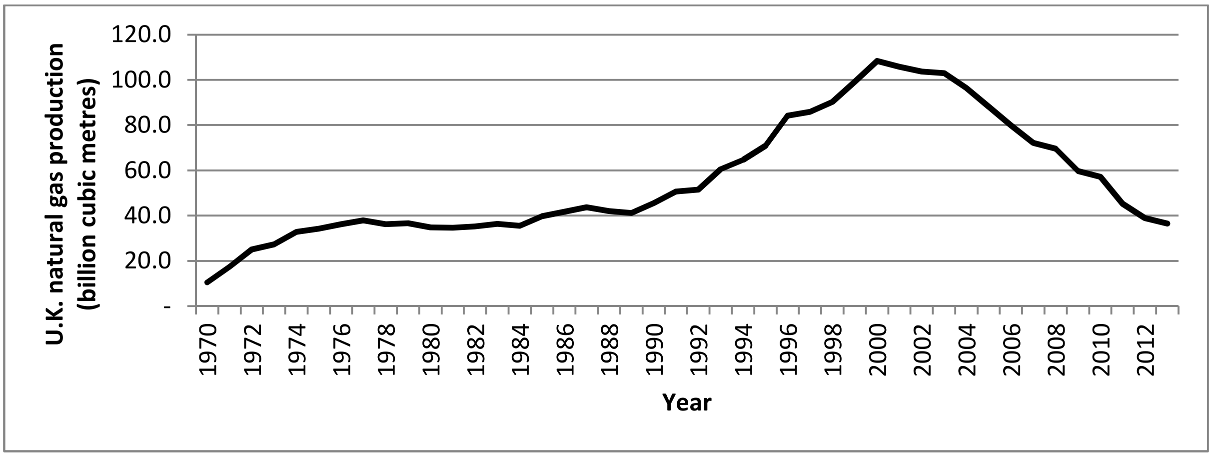

Figure 2.1: U.K. annual gas production in billion cubic metres (BP 2014).
Note: Gas production reached a peak in the year 2000 and steadily declined afterwards.

Following the rapid decline of conventional oil supplies, North America experienced similar consequences of oil scarcity until it began experiencing an 'unprecedented production growth' of shale and light, tight oil (LTO) using unconventional extraction methods such as hydraulic fracturing technology. IEA (2012, 2014) predicted that by 2010, "North America will have the capacity to become a net exporter of oil liquids", a net exporter of gas by 2020 and become almost self-sufficient in energy by 2035. Countries such as Canada, Russia and Argentina also seek to replicate this unconventional oil revolution (IEA 2014). Despite the growth in oil supplies which may delay the peak of global oil production, the evidence is that unconventional oil supplies (e.g. shale oil and LTO) have replaced conventional oil supplies which have already peaked. These unconventional oil supplies are harder to extract and process, which can lead to higher costs (Chapman 2014). Further exploitation of oil resources instead of adopting renewable energy has simply increased the rate of depletion of the finite stocks.

Both sides of the peak oil argument rely on different viewpoints of resource depletion. Critics of the peak oil argument are optimistic that higher prices and technological advances will open up more oil reserves and delay the peak of oil production. Supporters of the peak oil theory argue that cheap oil has peaked or is close to approaching a peak. There is a need to define the resource problem clearly, whether it involves a decrease in the resource in nature, or the resource stock in the economy.

2.5. RESOURCE DEPLETION IN LCA METHODOLOGY

The life cycle assessment (LCA) methodology is a systematic approach used to assess the environmental impacts over the life cycle of a product, from raw material acquisition to product use and disposal. The International Standard ISO 14040 (2006a) and ISO 14044 (2006b) outlines the four phases of LCA studies, which are the goal and scope definition, inventory analysis, impact assessment and interpretation of results. The raw material consumption and emissions from each life cycle stage are gathered to form the life cycle inventory (LCI). A life cycle impact assessment (LCIA) framework then analyses the environmental mechanisms of each substance emitted or resource consumed. A depiction of the LCIA framework can be found in Figure 2.2.

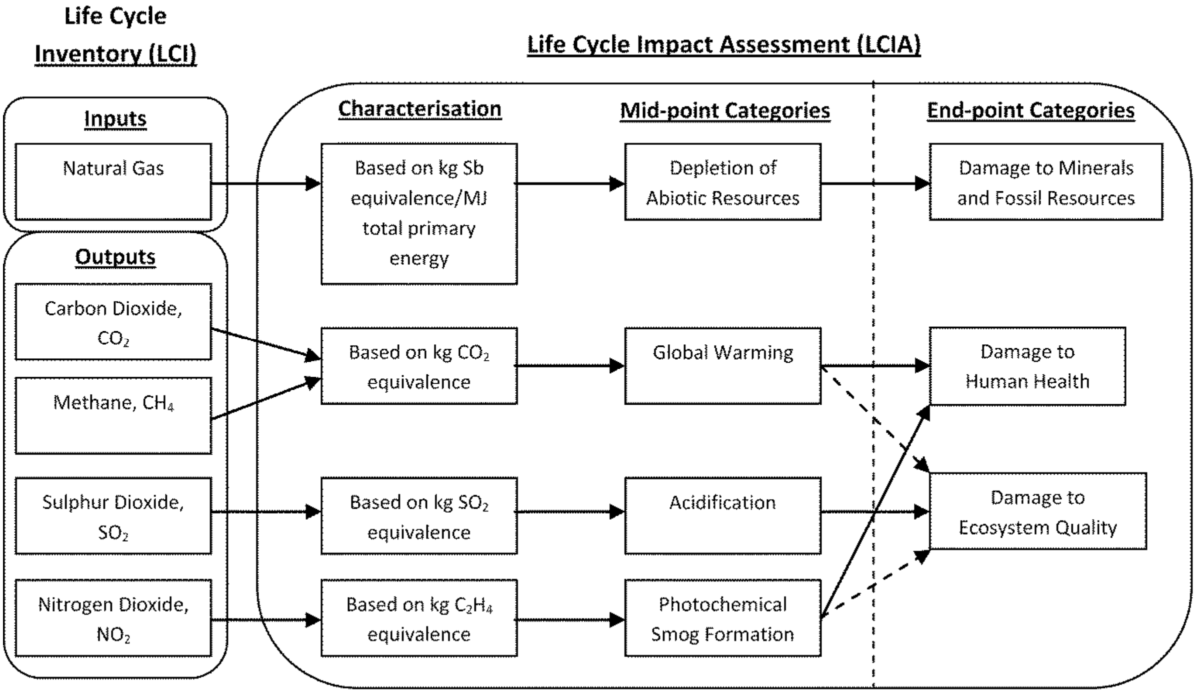

Figure 2.2: A typical life cycle impact assessment (LCIA) framework linking life cycle inventory (LCI) via mid-point categories to end-point categories for selected damage types.
Note: Indicators can be formed from either category after normalisation and optional weighting step.

Along this environmental mechanism, indicators can be chosen at the midpoint level between the inventory data and the ultimate damage caused by the substances. This is called the problem-oriented approach, where the environmental burdens are aggregated according to their relative contributions to the environmental effects that they may have (Azapagic 2006). The mid-point impact categories have environmental themes such as global warming, acidification, photochemical oxidant formation and resource depletion. Mid-point indicators have the advantage of relying primarily on scientific information and well-proven facts, and the amount of subjectivity and uncertainty involved is limited (UNEP SETAC Life Cycle Initiative 2008). Examples of mid-point characterisations can be found in the CML Handbook on LCA (Guinée et al. 2002b). In terms of fossil fuel depletion, the consumption of the resource in relation to its reserves is the concern.

Another approach is to choose the indicators at the endpoint level of the environmental mechanism. This is known as the damage-oriented approach, where the ultimate damage of the inventory substances to “areas of protection” (Azapagic 2006). These “areas of protection” are issues of concern which are easily understood such as human health, natural and man-made environment. The downside is that there is a significant uncertainty involved with assessing the severity of the damage. Examples of end-point characterisation can be found in the Eco-Indicator 99 method (Goedkoop & Spriensma 2001) and the ReCiPe method (Goedkoop et al. 2009).

In terms of fossil fuel depletion, the damage caused by the depletion is the main concern rather than the depletion of the resource. Indicators for abiotic resources attempt to capture the consequences of resource extraction, apart from diminishing of stocks and deposits as the most immediate impacts. These can include the additional energy to extract a lower quality resource in the future (Eco-Indicator 99) or the additional costs society has to pay to replace depleted resources with unconventional resources (ReCiPe 2008). These end-point methods will be discussed in Chapter 2.6.

The International Reference Life Cycle Data System (ILCD) Handbook was published by the Institute for Environment and Sustainability in the European Commission Joint Research Centre (JRC) to provide recommendations of best practice LCIA methods for each impact category. Among its recommendations for assessing resource depletion was to only consider methods that have an element that reflects the scarcity of the resource, as the limitations to the availability of the resource to current and future generations was identified to be the key concern for this impact category (EC-JRC 2010b). Table 2.2 summarises the mid-point and end-point characterisation methods recommended by the ILCD Handbook.

Table 2.2: Methods recommended by the ILCD Handbook for assessing resource depletion (EC-JRC 2010b)

Mid-point method	Description	Reference
Swiss Ecoscarcity (energy)	Uses net calorific value of fuels as basis of characterisation	Frischknecht et al. (2008)
Exergy	Uses exergy values for resources including fossil fuels, minerals, nuclear energy, land, renewable resources and water	Dewulf et al. (Dewulf 2007)
CML2002	Uses characterisation factors called 'Abiotic Depletion Potentials' and expressed in kg equivalent of a reference element	Guinée et al. (2002b)
EDIP1997 (2004 update)	Characterisation model based on annual production rates and economic reserves; Characterisation factors expressed in 'person-reserve' or resource quantity available to average citizen	Hauschild & Wenzel (Hauschild & Wenzel 1998)
MEEUP (water)	Only concerned about water for used for process and cooling; Characterisation factor expressed as 'amount of water used (litres)'	Kemna et al. (2005)
Swiss Ecoscarcity (water)	Only concerned about water; Differentiates regional severity of water availability	Frischknecht et al. (Frischknecht et al. 2009)
End-point method	**Description**	**Reference**
Eco-Indicator 99	Uses Surplus Energy or additional energy requirements due to mining resources with a decreased grade at some point in the future; uses Cultural Theory to deal with subjective choices on endpoint level	Müller-Wenk (1998), Goedkoop (1999)
EPS2000	Directly applies normalisation and weighting using monetisation on amount of resource depleted; Characterisation factors are expressed in Willing-To-Pay (WTP), indicating the costs of extracting and purifying the element	Steen (1999b)
IMPACT2002+	Similar to Eco-Indicator 99; Characterisation factor of fossil fuels expressed as total primary energy	Jolliet et al. (2003)
ReCiPe	Measures the marginal increase of oil production costs due to the need to mine unconventional oils; Characterisation factors expressed as Surplus Costs, which indicates that after extraction of the highest grade resources, future mining becomes more expensive	Goedkoop et al. (2009)

2.6. DEFINITION OF THE DEPLETION PROBLEM

Klinglmair (2014) reviewed current resource depletion indicators and found that there are varying perspectives on the definition and impacts of interest for resource depletion. Hauschild (2013) posed the question: "What is it that we want to protect within the abiotic resource depletion category and which impacts are relevant for the area of protection?" The environmental problem that is associated with the extraction and depletion of abiotic resources can be interpreted different ways, thus it is possible to produce many characterisation methods.

Heijungs et al. (1997) stated that the extraction of abiotic resources is responsible for a large number of environmental problems, mainly:

- The impacts connected with mining and/or purification
- The impacts connected with landscape occupation and/or exploitation
- The impacts connected with the reduced availability (or scarcity) of the resource

With the first impact type, there may be potential double counting of impacts in the LCA methodology. For example, CO_2 emitted from the mining stage falls under the LCA global warming category. The second impact type, which includes land use, also has its own separate category in the LCA framework. Thus, the impacts arising from the scarcity of the resource were recognised to be the main problem of abiotic resource depletion. Some of the impacts listed by Heijungs et al. (1997) were:

- the depletion of the reserve
- the loss of options for future generations
- the increase of environmental impacts of mining in future because the easily accessible ones will be depleted first.

Heijungs et al. (1997) then evaluated characterisation methods for extraction of abiotic resources based on criteria of their compliance with LCA principles, clear definition of depletion problem, avoidance of double counting, unambiguity, and ease of use. These characterisation methods included:

- aggregation of abiotic resources based on mass
- aggregation of abiotic resources (energy carriers) based on energy content
- aggregation of abiotic resources weighted with a measure of the reserve, for example:
    - the reserve base
    - the economic reserve
    - the ultimate reserve
    - the ultimately extractable reserve
- aggregation of abiotic resources weighted with reserves and global annual extraction rates
- aggregation of abiotic resources based on energy content
- normalisation of abiotic resource use based on annual production per capita of resource and valuation by dividing by the depletion time of the resource
- future impacts of abiotic resource depletion, e.g. energy required to bring resources back into their initial state, future claim on energy and land
- change in depletion time of resource, taking into account resource productivity improvement

Heijungs et al. (1997) concluded that no single method is good with respect to all criteria. The definition of the environmental problem caused by resource depletion is crucial. Their recommendation was to use reserves and global annual extraction rates to form the resource depletion indicator.

The numerous methodologies for the impact assessment of resource use were reviewed by the SETAC Working Group IA-2 (Lindeijer et al. 2002, Stewart & Weidema 2005) and other authors (Guinée et al. 2002b, Steen 2006, EC-JRC 2010a). These are categorised into four main approaches:

- mass or energy
- use of stock or deposit
- exergy or entropy
- future consequences of resource extraction (scarcity or extra need for energy for extraction)

The four approaches reflect the socio-economic concerns of resource depletion, i.e. the notion that extraction of a resource from the natural environment leads to a decrease in its future availability or increase in future energetic and economic costs. Environmental and human health impacts related to the extraction and use of fossil fuel resources are kept as separate environmental impact categories.

Therefore, there is currently no indicator that shows how resource depletion directly impacts ecosystem or human health.

2.6.1. MASS OR ENERGY

The first characterisation method is based on the mass or energy content of the abiotic resources produced. This suggests that all abiotic resources can be treated equally on a mass or energy basis and can be exchangeable (Steen 2006). Furthermore, the nature of the ore body was not considered (e.g. concentration, location and depth). These indicators are not widely used in LCIA (Lindeijer et al. 2002, Steen 2006).

2.6.2. RESOURCE DEPOSIT AND CONSUMPTION

The second characterisation method is based on the relation of resource use and the resource deposits. Stewart & Weidema (2005) summarised three different aggregations (*Q*) according to the measure of reserve deposits (*D*) and current consumption (*U*):

- $$Q = \frac{1}{D} \qquad \text{(Equation 2.1)}$$
- $$Q = \frac{U}{D} \qquad \text{(Equation 2.2)}$$
- $$Q = \frac{1}{D} \times \frac{U}{D} \qquad \text{(Equation 2.3)}$$

Guinée & Heijungs (1995) and Stewart & Weidema (2005) argue that the availability of reserve deposits are dependent on economic and socio-political factors. These indicators can have a significant element of arbitrariness as *D* can represent identified reserves of concentrates that can be economically extracted, or anticipated amounts of such concentrates, or total amount of a substance in the earth's crust. Because of this, Guinée & Heijungs (1995) opted for a pure environmental indicator, taking the total amount in the earth's crust and only the extraction from the earth to be of interest. There is an assumption about the exchangeability of resources such that depletion of specific resources is less critical if there are substitutes available.

This type of indicator can be found in the first and second CML Handbook on LCA (Heijungs et al. 1992, Guinée et al. 2002b). The first CML Handbook on LCA by Heijungs et al. (1992) assessed the depletion of abiotic resources by comparing the quantity used of each raw material (e.g. energy carriers and metals) in the LCI with the recoverable reserves of the raw material, whose reserves may become insufficient within 100 years. The effect score of the depletion of abiotic resources is calculated using a dimensionless expression as shown in Equation 2.4.

$$\text{Abiotic depletion} = \sum_i \frac{\text{Material use}_\text{i}\ (kg)}{\text{Reserves}_\text{i}\ (kg)} \qquad \text{(Equation 2.4)}$$

The reserve data were based on 1991 data from the World Resources Institute and were limited to energy carriers (crude oil, natural gas and uranium) and metals (cadmium, copper, lead, mercury, nickel, tin and zinc). Resources with longer lifetimes (e.g. coal) were not included. The chosen resources were essentially deemed to be most at risk of resource depletion and scarcity.

This approach was modified in the second edition of the CML 2002 method by Guinée (2002b) where extraction rates (*Δx*) were used in conjunction with global reserves (*Re*) (See Equation 2.5) .Guinée (2002b) concluded the depletion of the resource itself is the problem and the best available method is one that is based on reserves and/or current extraction methods. Economic reserves involve a variety of economic considerations not directly related to the environmental problem of resource depletion. Antimony was used as a reference and was initially discussed in Guinée and Heijungs (1995). A different indicator was used for energy resources, assuming that different fossil fuels have different heating values on a weight basis. Therefore, one common approach is to aggregate all forms of energy consumption and form a common Abiotic Depletion Potential (ADP) for fossil fuels of all types, expressed in kg antimony eq./MJ fossil energy. The ultimate reserves of fossil fuels were obtained from 1994-1995 data for total proven commercial reserves of coal, oil and natural gas from the World Resources Institute. ADP for individual fossil fuels (e.g. natural gas) can be derived by multiplying this overall fossil energy ADP with their respective heating value, with the final indicator expressed in kg antimony eq./kg fossil fuel extracted.

$$\mathrm{ADP}_{\text{fossil energy}} = \frac{\Delta x_{\text{fossil energy}}}{\left(\mathrm{Re}_{\text{fossil energy}}\right)^2} \times \frac{\left(\mathrm{Re}_{\text{antimony}}\right)^2}{\Delta x_{\text{antimony}}} \qquad (\text{ Equation 2.5 })$$

2.6.3. ENTROPY AND ENERGY

The third characterisation method is based on entropy and/or exergy impacts. Entropy is a thermodynamic quantity that can be interpreted as a measure of the randomness of the system. For example, the entropy of a metal in a high quality ore is low, while the entropy of the same metal dispersed around the world is high. Exergy is a quantity that refers to the amount of available or useful energy. When an energy carrier is used, the energy is conserved but what is lost is the quality or the potential to use that energy. Exergy is slowly growing in popularity as a measure of resource depletion because it combines aspects of quantity and quality (EC-JRC 2010a). Finnveden & Östlund (1997) states that useful energy (exergy) is the ultimate limiting resource as each material resource has its own associated energy cost, and one of the reasons a resource is limited is because its energy costs are too high. Finnveden & Östlund (1997) suggests that the potential exergy of an ore might be used as a measure of abiotic resources in LCA (i.e. the decrease in reserves of useful energy or exergy in the world).

Steen (2006) argues that exergy will ultimately be limiting, but not until it has reached an impractical upper limit. Klinglmair et al. (2014) states that accounting for depletion in exergy disregards a resource functionality and possible limited capacity of being substituted with another resource and thus misrepresent its actual scarcity, but this was only observed for non-energy resources (e.g. metals). Ultimately, the motivation to use this indicator is because mining costs are seen as the problem of resource depletion. Alternatively, exergy analysis can be used to quantify environmental impacts instead of mining costs (Simpson & Edwards 2011) and is more relevant as a tool to increase efficiency and reduce the environmental impact of a product (Rosen et al. 2008).

2.6.4. FUTURE CONSEQUENCES

The fourth characterisation method is based on future consequences of resource extractions. The idea is that extracting high quality resources today will force future generations to extract lower quality resources. This leads to an increased environment and economic impacts for future resource extraction as compared to current resource extraction. Several examples are the concept of ‘surplus energy' in the Eco-Indicator 99 method (Goedkoop & Spriensma 2001) and 'marginal costs' in the ReCiPe 2008 method (Goedkoop et al. 2009). There are different ideas about which time perspective to apply depending on the scenario. For example, the Eco-Indicator 99 method chose a timeframe in the future where mankind has extracted an amount that is N times the cumulative extracted materials since the beginning of extraction up until 1990.

The Eco-Indicator 99 method is a damage-oriented approach used in LCA to link mid-point impact categories into three major end-point damage categories, namely "damage to human health", "damage to ecosystems", and "damage to resources". Resource depletion is measured based on 'surplus energy' or the difference between the energy needed to extract a resource now and at some point in the future. This arises from the assumption that as the resources of higher quality are exploited first, the remaining resources are of lower quality and the effort to extract and process those increases. The 'surplus energy' damage indicator was measured in MJ per kg of resource extracted.

This concept was extended in the ReCiPe 2008 method (Goedkoop et al. 2009) which links resource consumption of fossil fuels to the additional costs society has to pay in replacing fossil fuels with unconventional sources (e.g. tar sands, uranium, wind or solar). The marginal cost indicator uses the extraction cost of conventional oil as a reference, against which other fossil fuel resources are compared. By monetising increased extraction efforts, it becomes possible to include a comprehensive range of resources using one metric (e.g. marginal increase of extraction cost per kilogram of extracted resource). According to Klinglmair (2014), monetization of extraction effort per functional unit (e.g. marginal cost in ReCiPe 2008) provides a more complete picture of supply constraints if one is to measure far-reaching impacts of extracting a certain amount of a given resource.

Both the Eco-Indicator 99 and ReCiPe 2008 methods use the Cultural Theory to formulate characterisation factors. This is based on cultural biases in different groups in society. Each group possesses its own perception of nature, resources and environmental risk, which is then linked to perceived solutions to reduce environmental risks. Steg and Sievers (2000) categorised these groups into four different perspectives:

- Individualists view nature as a stable and global equilibrium that is resilient. They are not concerned by environmental problems and they view resources as abundant. They adopt a business-as-usual attitude, where present needs outweigh the needs of future generations. Environmental risks are seen as opportunities rather than threats and technological solutions will eventually arise, hence they are inherently risk-seeking. Their risk management strategy lies on the market system, as they oppose collective control systems such as government regulation.
- Hierarchists view nature as robust and are willing to take acceptable environmental risks up to a certain point as determined by experts and authorities. They view nature as an unstable equilibrium and they view resources as scarce. They believe environmental problems can be controlled by government regulations based on experts' knowledge on the limits of growth. Their risk management strategy is sustainable growth and aimed at controlling resources.
- Egalitarians view nature as a limited equilibrium and view resources are depleting. They are more risk-averse because they believe environmental risks lead to disastrous consequences. They strive to contribute to the solution of environmental problems by reducing their needs. They believe in equal sharing of finite resources and prefer management strategies that treat the needs of the present generation and future generation equally.

- Fatalists view nature as unmanageable and everything happens by chance, so they learn to cope with whatever outcomes may arise from environmental risks. This perspective is not included in the Eco-Indicator 99 method and the ReCiPe method.

According to the ILCD Handbook, the CML 2002 method was identified as the best among the existing models for mid-point characterisation, while the ReCiPe method was identified as the best among existing end-point models (Hauschild et al. 2013).

2.6.5. OTHER CHARACTERISATION MODELS

In addition to reserves, annual extraction rates, energy, and future consequences such as surplus cost and marginal costs, Klinglmair (2014) also identified two other characterisation models for assessing resource depletion, which are Willingness-To-Pay (WTP) and distance-to-target. WTP models aim to capture the monetary costs of avoiding damages to an area of protection, which is abiotic resource availability in this case. The EPS 2000 method (Steen 1999b) uses this approach to weigh the impacts from resource depletion. For abiotic resources, the cost of substituting a substance by a sustainable alternative is used as a WTP value for future generations affected by present day depletion. Market prices are used as a basis to quantify the costs of substitution. Distance-to-target approaches set environmental impacts against predefined targets such as a critical resource flow.

2.7. RESOURCE DEPLETION OUTSIDE LCA METHODOLOGY

Outside of the LCA methodology, indicators have been formulated using similar principles as those used in the LCA methodology. Lee (1998) formulated a Resource Depletion Index (RDI) that uses the ratio of de-accumulation to reserves similar to that used by Guinée & Heijungs (1995). The index is expressed as the life (in years) of the current resource base given the current extraction rate for a certain year. Estimates of the recoverable reserves are influenced by the cost structures and available technology at the time of making the estimate. The indicator can be used in the local or global context. The indicator simplifies the depletion problem and does not correct for future conditions. It was assumed that there is no price increase resulting from the depletion of the resource, which will discourage consumption of the resource in favour of other resources with lower prices. It was also assumed that no new reserves are unlocked due to the development of more advanced technologies and equipment in the future. Lee intended the indicator to be a ‘simple and easily understood indicator to describe a present resource depletion condition’.

2.8. GAPS IN RESEARCH

There is currently a lack of consensus among LCA practitioners on what the main issue of abiotic resource depletion (EC-JRC 2010a, Klinglmair et al. 2014). However, in terms of far-reaching consequences of resource depletion, monetisation of the extraction effort per functional unit of resource provides a more complete picture of supply constraints. However, this is only one impact of resource depletion. A general limitation of resource depletion indicators developed thus far is that they do not show the full consequences of the depletion of the resource outside of their decreasing future quantity or accessibility. Other environmental impacts are restricted to their own indicators (e.g. greenhouse gas emissions under global warming impacts). Current resource depletion indicators do not reveal the externalities or hidden costs which become a burden for the other areas of protection (i.e. ecosystem and human health). Hirsch et al. (2005) do not take into account the environmental impacts of switching to ‘dirtier’ fuel (i.e. from conventional oil and gas to coal and shale oil and gas). Others have attempted to capture the costs of externalities for depletion of resources, including water (Steen 1999a, Reddy 2005).

Many authors have assumed substitution of fossil fuels. Guinée et al. (2002b) assumed fossil fuels to be substitutable for one another to provide energy, but this assumption does not account for the difference in energy and costs required and emissions produced from different fossil fuels. Others assume substitution to alternatives to be a consequence of scarcity, prompting the increased energy (e.g. surplus energy) and costs (e.g. marginal costs) of extraction. The Eco-Indicator 99 method quantifies the damage resulting from substituting a depleted resource with an alternative resource. However, the damage is only considered in terms of energy required per mass of the replaced resource. Other environmental impacts resulting from the substitution such as global warming and acidification are not assessed. ReCiPe 2008 estimates the damage of the resource depletion in terms of an economic cost, but this cost reflects only the extraction costs related to the substitution and not the wider cost of environmental damage resulting from the substitution. In methods such as Eco-Indicator 99 and ReCiPe 2008, the exact occurrence of the substitution or scarcity is not important, only the impacts are of concern.

2.9. AIM OF RESEARCH

From the literature surveyed, there is currently no consensus on which resource depletion indicators capture the impacts of resource depletion adequately, given that there are a range of different impacts caused by resource depletion and each existing resource depletion methodology focuses on a specific impact. This study proposes a methodology to address the wide range of resource depletion impacts. The methodology measures the different consequences of resource depletion based on the impacts of substitution to an alternative resource during resource scarcity. This methodology will be assessed using a case study of natural gas scarcity in Australia and capture the resulting impacts across different Australian economic sectors that rely on natural gas. The case study explores the substitution of natural gas with black coal, CSG and diesel and explores upstream and downstream impacts. The methodology converts environmental and economic data into indicators and normalises them to reflect the Australian situation and enable comparisons between different impact categories.

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Chapter 3

Methodology

3.1. OVERVIEW

This chapter describes the substitution methodology and those features that separate it from the traditional Life Cycle Impact Assessment (LCIA) methodology. The chapter provides a derivation of the indicators that are based on substitution impacts. A worked example is provided where natural gas is substituted with black coal. The case study measures the greenhouse gas impacts of the substitution for two different natural gas users: electricity generation and hydrogen production. First, the substitution impacts of the two sectors are examined separately. Secondly, the substitution impacts are added cumulatively from both sectors to perform an example of a system-wide analysis and reveal the overall substitution consequences of a natural gas scarcity.

3.2. SUBSTITUTION IMPACT METHODOLOGY

Figure 3.1 shows a graphical representation of the substitution methodology using a change in global warming impact when natural gas is substituted in electricity generation as an example. The conventional LCIA calculation as outlined in Chapter 2.5 and depicted in Figure 2.2 is enclosed by the dotted line. The substitution methodology is the difference between two LCIA calculations, where the substitute resource takes part in the lower chain of calculations as depicted in Figure 3.1. The substitution indicator is obtained from the difference between the mid-point impact category indicators for both the original resource and alternative resource for a common reference unit and common extent or scope of the life cycle. The substitution impact indicator will have a common reference unit of tonne per tonne resource substituted for environmental impacts, or Australian dollars per tonne resource substituted for economic impacts. ‘Per tonne resource substituted’ was chosen because the mass of fossil fuels can be calculated for all sectors studied, whereas energy units are only applicable to certain sectors only.

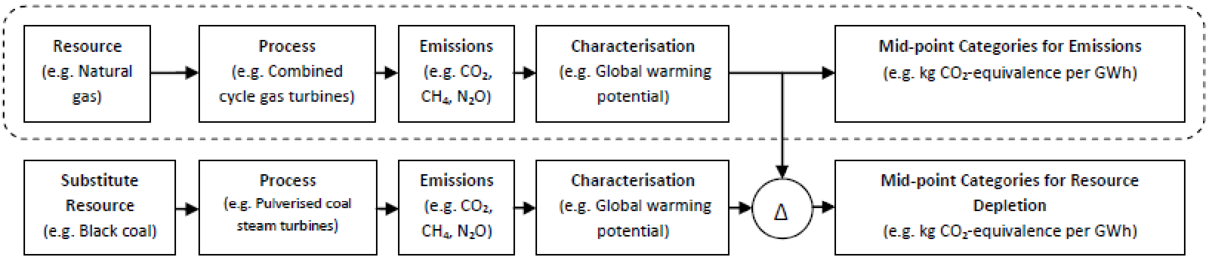

Figure 3.1: The proposed substitution methodology to calculate a change in globl warming impact when natural gas is substituted with black coal in electricity generation.

Note: The dotted box represent the system boundary of a traditional LCIA; the proposed methodology will extend the system boundary to include the additional steps as shown. The Δ operator calculates the difference between the two systems.

3.3. DERIVATION OF SUBSTITUTION IMPACT INDICATORS

Figure 2.2 in Chapter 2.5 shows the LCIA framework linking LCI to mid-point impact categories. The LCI represents inputs and outputs for a product system. This is represented differently in Figure 3.2, which shows a generic product system with a resource input *x*, a product output *y* and a produced impact or a range of produced impacts z_k, where the subscript k denotes a specific mid-point impact category, $k = 1, 2, 3$, etc.

Each product system will vary depending on the resource and the unique conversion pathway to obtain the product. The resource types are each represented by a subscript $i = 1, 2, 3$, etc. and the conversion pathway from resource to product is represented by a subscript $j = 1, 2, 3$, etc. Thus, the resource input, product output and produced impacts are rewritten as x_{ij}, y_{ij} and $(z_k)_{ij}$. A product system corresponding to the original resource is given the subscript $i = 0$.

y is a measureable quantity of product in tonnes per year (t/yr). x and z_k are used to denote specific quantities of resource and impacts respectively in tonnes of resources or tonnes of emissions per tonne of product[‡‡] (t/t).

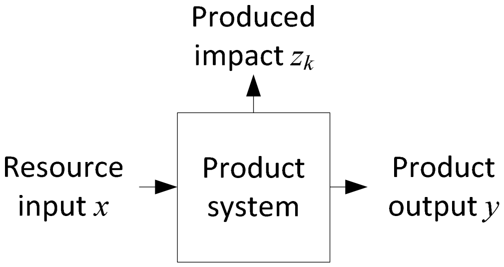

Figure 3.2: Diagram of a product system showing the resource input x, the product output y and the impacts produced z.

3.3.1. SECTOR-SPECIFIC RESOURCE DEPLETION INDICATOR

When a product system generating product y switches from the original resource ($i = 0$) to an alternative resource i due to resource depletion and scarcity, the result will be a difference in annual mid-point category impacts $\Delta(Z_k)_{ij}$. A depiction of this is shown in Figure 3.1. $\Delta(Z_k)_{ij}$ is calculated using Equation 3.1 below.

$$\Delta(Z_k)_{ij} = \left[(z_k)_{ij} - (z_k)_{0j} \right] (y_j) \qquad (\text{Equation 3.1})$$

where
$\Delta(Z_k)_{ij}$ = difference in annual impacts (t/yr)
$(z_k)_{ij}$ = impact indicator corresponding to the alternative resource (t/t)
$(z_k)_{0j}$ = impact indicator corresponding to the original resource (t/t)
y_j = annual product output (t/yr)

Equation 3.1 is written such that a positive value (+) indicates an increase in impacts, or impact penalties, as a result of the substitution, while a negative value (-) indicates a decrease or credit in impacts, or impacts that were negated or avoided as a result of the substitution.

The difference between annual impacts $\Delta(Z_k)_{ij}$ is divided by the annual natural gas consumption to obtain the substitution impact indicator $\Delta(Z_k)^R_{ij}$ as shown in Equation 3.2.

[‡‡] There are exceptions for certain products. Electricity, for example, will use tonnes per MWh instead.

$$\Delta\left(Z_k\right)_{ij}^{R} = \frac{\Delta\left(Z_k\right)_i}{x_j y_j} \qquad \text{(Equation 3.2)}$$

where
$\Delta(Z_k)^R_{ij}$ = difference in impacts per tonne original resource substituted (t/t)
x_j = original resource consumed/substituted (t/t)

Equation 3.2 uses the original resource consumption x_j to represent the amount of original resource that has been substituted.

3.3.2. SYSTEM-WIDE RESOURCE DEPLETION INDICATOR

The indicator in Equation 3.2 measures the change in impacts due to the substitution of resources in the production of a single product. The substitution impact methodology aims to measure the change in impacts due to substitution of resources in multiple products. The unit quantities x_{ij} and $(z_k)_{ij}$ from different products cannot be added together to form a single indicator because they each have a different basis depending on the product. To solve this, the methodology converts x_{ij} and $(z_k)_{ij}$ into annual quantities with a common basis of t/yr. Equation 3.1 is modified to enable the summation of all changes in annual impacts across all processes y_j as shown in Equation 3.3.

$$\Delta\left(Z_k\right)_i = \sum_{j=1}^{n}\left\{ \left[\left(z_k\right)_{ij} - \left(z_k\right)_{0j} \right] \left(y_j\right) \right\} = \sum_{j=1}^{n}\left[\Delta\left(Z_k\right)_{ij} \right] \qquad \text{(Equation 3.3)}$$

Similarly, Equation 3.2 is modified to enable the summation of all annual natural gas consumptions across all processes y as shown in Equation 3.4. This indicator corresponds to a specific alternative resource i.

$$\Delta\left(Z_k\right)_i^{R} = \frac{\Delta\left(Z_k\right)_i}{\sum_{j=1}^{n}\left[x_j y_j\right]} \qquad \text{(Equation 3.4)}$$

In cases where more than one alternative resource is required to cover substitution in all products, Equation 3.5 is used. The change in annual impacts is calculated for all processes before dividing with the annual gas consumptions across all processes.

$$\Delta\left(Z_k\right)^{R} = \frac{\sum_{i=1}^{n}\sum_{j=1}^{n}\left[\Delta\left(Z_k\right)_{ij} \right]}{\sum_{j=1}^{n}\left[x_j y_j\right]} \qquad \text{(Equation 3.5)}$$

3.4. DEMONSTRATION OF SUBSTITUTION METHODOLOGY

The substitution methodology is demonstrated using a worked example by examining a simplified substitution of natural gas with black coal. Only the impacts associated with global warming ($k = 1$) arising from the substitution are demonstrated. In this example, three processes were chosen to represent the impacts of substitution due to natural gas scarcity in different products using different feedstocks.

j = 1 is represented by baseload grid electricity generation. For the natural gas case (i = 0), baseload grid electricity is generated through combined cycle gas turbine (CCGT) technology. In the event of a scarcity, black coal (i = 1) was chosen as the alternative resource, and electricity is generated through pulverised coal steam turbine (PCST) technology. The global warming impacts for gas- and coal-based electricity, annual gas-based electricity generation and annual natural gas consumption are presented in detail in Chapter 4.3.

j = 2 is represented by peaking grid electricity generation. For the natural gas case, (i = 0), peaking grid electricity is generated through open cycle gas turbine (OCGT) technology. In the event of a scarcity, diesel (i = 2) was chosen as the alternative resource, and electricity is generated using diesel engines. The global warming impacts for gas- and diesel-based electricity, annual gas-based electricity generation and annual natural gas consumption are presented in detail in Chapter 4.3.

j = 3 is represented by residential heating. For the natural gas case (i = 0), heating is produced by the combustion of natural gas. In the event of a scarcity, black coal (i = 1) was chosen as the alternative resource, and heating is produced by reverse cycle units powered by black-coal generated electricity. The global warming impacts for gas- and coal-based residential heating, annual gas-based heating and annual natural gas consumption is presented in detail in Chapter 4.7.

Table 3.1 summarises the key information for grid electricity generation and residential heating, which are used in the methodology.

Table 3.1: Key results for grid electricity generation and residential heating cases

Process	Baseload grid electricity generation (j = 1) (Unit = MWh)		Peaking grid electricity generation (j = 2) (Unit = MWh)		Residential heating (j = 3) (Unit = $MJ_{heating}$)	
Feedstock/ technology	Natural gas (i = 0) in CCGT	Black coal (i = 1) in PCST	Natural gas (i = 0) in OCGT	Diesel (i = 2) in diesel engines	Natural gas (i = 0) in gas heating	Black coal (i = 1) in reverse cycle heating
Global warming potential, $(z_1)_{ij}$ (t CO_2-eq./unit)	0.359	0.784	0.524	0.675	0.0778	0.0681
Annual production, y_j (unit/yr)	4.04×10^7	-	8.84×10^6		4.88×10^7	-
Natural gas consumed/substituted, x_j (t/unit)	0.136	-	0.199		0.0240	-

3.4.1. SINGLE RESOURCE SUBSTITUTION FOR A SINGLE PROCESS

Assume natural gas scarcity occurs in the grid electricity generation sector and in the residential sector. Each system is treated separately and will have its own individual substitution impact indicators.

For substitution of natural gas with black coal (i = 1) in the baseload grid electricity (j = 1), the change in annual greenhouse gas emissions $\Delta(Z_1)_{11}$ is calculated using Equation 3.1 together with global warming potentials and annual production figures from Table 3.1.

$$\Delta\left(Z_1\right)_{11} = \left[\ \left(z_1\right)_{11} - \left(z_1\right)_{01}\right]\ \left(y_1\right)$$
$$\Delta\left(Z_1\right)_{11} = \left[0.784 - 0.359\right] t\ CO_2 eq./MWh\left(4.04\times10^7\ MWh/yr\right)$$
$$\Delta\left(Z_1\right)_{11} = +1.72\times10^7\ t\ CO_2 eq./yr$$

The substitution indicator $\Delta(Z_1)^R_{11}$ is then calculated using Equation 3.2 together with $\Delta(Z_1)_{11}$ and the total natural gas consumption figure from Table 3.1.

$$\Delta\left(Z_1\right)^R_{11} = \frac{\Delta\left(Z_1\right)_{11}}{x_1\left(y_1\right)}$$
$$\Delta\left(Z_1\right)^R_{11} = \frac{+1.72\times10^7\ t\ CO_2 eq./yr}{0.136\text{t natural gas substituted}/MWh\left(4.04\times10^7\ MWh/yr\right)}$$
$$\Delta\left(Z_1\right)^R_{11} = +3.13 t\ CO_2 eq./\text{t natural gas substituted}$$

The substitution indicator shows the impact that occurs when the original resource is replaced with the alternative. In this case, 3.13 tonnes of CO_2-eq. of greenhouse gas emissions were emitted for every tonne of natural gas substituted with black coal in electricity generation. The positive sign shows that the substitution from natural gas to black coal results in an increase in greenhouse gas emissions.

For substitution of natural gas with diesel (i = 2) in the generation of peaking grid electricity (j = 2), the change in annual greenhouse gas emissions $\Delta(Z_1)_{22}$ is calculated using Equation 3.1 together with global warming potentials and annual production figures from Table 3.1.

$$\Delta\left(Z_1\right)_{22} = \left[\ \left(z_1\right)_{22} - \left(z_1\right)_{02}\right]\ \left(y_2\right)$$
$$\Delta\left(Z_1\right)_{22} = \left[\ 0.675\text{-}0.524\right] t\ CO_2 eq./t\ \text{MWh}\left(8.84\times10^6\ MWh/yr\right)$$
$$\Delta\left(Z_1\right)_{22} = +1.33\times10^6\ t\ CO_2 eq./yr$$

The substitution indicator $\Delta(Z_1)^R_{22}$ is then calculated using Equation 3.2 together with $\Delta(Z_1)_{22}$ and the total natural gas consumption figure from Table 3.1.

$$\Delta\left(Z_1\right)^R_{22} = \frac{+1.33\times10^6\ t\ CO_2 eq./yr}{0.199\,\text{t natural gas substituted}/MWh\left(8.84\times10^6\ MWh/yr\right)}$$
$$\Delta\left(Z_1\right)^R_{22} = +0.759\, t\ CO_2 eq./\text{t natural gas substituted}$$

For substitution of natural gas with black coal (i = 1) in residential heating (j = 3), the change in annual greenhouse gas emissions $\Delta(Z_1)_{22}$ is calculated using Equation 3.1 together with global warming potentials and annual production figures from Table 3.1.

$$\Delta(Z_1)_{13} = \left[(z_1)_{13} - (z_1)_{03} \right] (y_3)$$

$$\Delta(Z_1)_{13} = [\ 0.0681\text{-}0.0778]\, t\ CO_2 eq./t\ \mathrm{MJ}_{heating} \left(4.88\times10^7\ \mathrm{MJ}_{heating}/yr\right)$$

$$\Delta(Z_1)_{13} = -4.73\times10^5\ t\ CO_2 eq./yr$$

The substitution indicator $\Delta(Z_1)^R_{13}$ is then calculated using Equation 3.2 together with $\Delta(Z_1)_{13}$ and the total natural gas consumption figure from Table 3.1.

$$\Delta(Z_1)^R_{13} = \frac{-4.73\times10^5\ t\ CO_2 eq./yr}{0.0240\,\mathrm{t\ natural\ gas\ substituted}/MWh\left(4.88\times10^7\ MWh/yr\right)}$$

$$\Delta(Z_1)^R_{13} = -0.404\,t\ CO_2 eq./\mathrm{t\ natural\ gas\ substituted}$$

The greenhouse gas emission increase per tonne natural gas substituted for baseload electricity generation $\Delta(Z_1)^R_{11}$ was found to be highest, followed by $\Delta(Z_1)^R_{22}$ for peaking grid electricity generation and $\Delta(Z_1)^R_{13}$ for residential heating. This indicates that the impacts of a natural gas scarcity are more severe in baseload electricity generation than for the other two sectors.

3.4.2. SINGLE RESOURCE SUBSTITUTION FOR MULTIPLE PROCESSES

Similar to the single resource substitution for a single process, the change in annual greenhouse gas emissions $\Delta(Z_k)_{ij}$ is calculated using Equation 3.1 together with global warming potentials and annual production figures from Table 3.1. For the case of substitution with black coal in baseload grid electricity generation and residential heating, $\Delta(Z_k)_{ij}$ for both processes is added cumulatively to obtain the overall $\Delta(Z_1)_1$ by using Equation 3.3.

$$\Delta(Z_1)_1 = \left\{ \left[(z_1)_{11} - (z_1)_{01}\right] (y_1) \right\} + \left\{ \left[(z_1)_{13} - (z_1)_{03}\right] (y_3) \right\}$$

$$\Delta(Z_1)_1 = \left(+1.72\times10^7 - 4.73\times10^5\right) t\ CO_2 eq./yr$$

$$\Delta(Z_1)_1 = +1.67\times10^7\ t\ CO_2 eq./yr$$

The substitution indicator $\Delta(Z_1)^R_1$ is then calculated using Equation 3.4 by dividing $\Delta(Z_1)_1$ by the total natural gas consumption in both the electricity generation and hydrogen production sectors from Table 3.1.

$$\Delta\left(Z_k\right)_i^R = \frac{\Delta\left(Z_k\right)_i}{\sum_{j=1}^{n}\left\{\ x_j\left(y_j\right)\ \right\}}$$

$$\Delta\left(Z_1\right)_1^R = \frac{\Delta\left(Z_1\right)_1}{x_1\left(y_1\right)+x_2\left(y_2\right)}$$

$$\Delta\left(Z_1\right)_1^R = \frac{+1.67\times10^7\,t\ CO_2eq./yr}{\left(5.49\times10^6+1.17\times10^6\right)\text{t natural gas substituted}/yr}$$

$$\Delta\left(Z_1\right)_1^R = +2.51t\ CO_2eq./\text{t natural gas substituted}$$

For the case of substitution with diesel in peaking grid electricity generation, $\Delta(Z_1)_2$ is calculated to be the same as the case for a single resource substitution for a single process, which is -0.404 t CO_2-eq./t natural gas substituted.

3.4.3. MULTIPLE RESOURCE SUBSTITUTION FOR MULTIPLE PROCESSES

In this case, natural gas scarcity was assumed to affect both the grid electricity generation sector and the residential sector at the same time. The result will be a substitution with black coal for baseload grid electricity generation and residential heating and with diesel for peaking grid electricity generation. The substitution impact indicator will then reflect the overall consequences for all three sectors. Equation 3.5 is used.

$$\Delta\left(Z_k\right)^R = \frac{\sum_{i=1}^{n}\sum_{j=1}^{n}\left[\ \Delta\left(Z_k\right)_{ij}\ \right]}{\sum_{j=1}^{n}\left[x_j y_j\right]}$$

$$\Delta\left(Z_1\right)^R = \frac{\left\{\ \left[\left(z_1\right)_{11}-\left(z_1\right)_{01}\right]\ \left(y_1\right)\ \right\}+\left\{\ \left[\left(z_1\right)_{22}-\left(z_1\right)_{02}\right]\ \left(y_3\right)\ \right\}+\left\{\ \left[\left(z_1\right)_{13}-\left(z_1\right)_{03}\right]\ \left(y_3\right)\ \right\}}{x_1\left(y_1\right)+x_2\left(y_2\right)+x_3\left(y_3\right)}$$

$$\Delta\left(Z_1\right)^R = \frac{\left(+1.72\times10^7-4.73\times10^5+1.33\times10^6\right)t\ CO_2eq./yr}{\left(5.49\times10^6+1.17\times10^6+1.76\times10^6\right)\text{t natural gas substituted}/yr}$$

$$\Delta\left(Z_1\right)^R = +2.26t\ CO_2eq./\text{t natural gas substituted}$$

Table 3.2 summarises the results from the demonstration of the substitution impact methodology to measure the effects of a natural gas scarcity in baseload and peaking grid electricity generation and residential heating. It can be seen that the combined indicator $\Delta(Z_1)^R$ acts as a weighted average of the substitution impact indicators for all sectors. As the baseload electricity generation sector consumes more natural gas annually as compared to the other sectors, the combined indicator $\Delta(Z_1)^R$ leans more towards the indicator for the electricity generation $\Delta(Z_1)^R_{11}$ than to that for hydrogen production.

Table 3.2: Substitution impact indicators for electricity generation and hydrogen production for resource substitution in a single process case and multiple processes case

Single resource substitution for a single process		
Baseload grid electricity generation	$\Delta(Z_1)_{11}^R$	+3.13 t CO_2-eq./t natural gas substituted
Peaking grid electricity generation	$\Delta(Z_1)_{22}^R$	+0.759 t CO_2-eq./t natural gas substituted
Residential heating	$\Delta(Z_1)_{13}^R$	-0.404 t CO_2-eq./t natural gas substituted
Multiple resource substitution for multiple processes		
Grid electricity generation and residential heating	$\Delta(Z_1)^R$	+2.26 t CO2-eq./t natural gas substituted

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Chapter 4

Results from Case Study of Natural Gas Use in Australia

4.1. DATA GATHERING METHOD

The data gathering is undertaken in two parts: environmental and economic. Data is sourced where possible from Australian sources in the relevant fields. Where possible, each data point is compared with values from other literature to verify its accuracy. In the event that there is no published data in Australia, or it is not possible to source from local data, data from similar projects overseas are adopted and adjusted to an Australian basis.

4.1.1. SCOPE, SYSTEM BOUNDARY AND ASSUMPTIONS

When compared to the system boundary of a typical Life Cycle Assessment (LCA), the system boundary in this analysis encompasses the upstream section, which consists of the extraction and purification stages, and the downstream section, which is made up of the manufacturing stage where the resource is converted into the end product. The transportation stage between the purification and manufacturing stage, as well as the usage and disposal stage, is not included in the analysis (see Figure 4.1). This is based on a simplification of the analysis such that the resource extraction point is relatively close to the downstream manufacturing point. In addition, the end product is identical for both the process using the original resource and the process using the alternative resource. Hence, another simplification is made such that the change in impacts related to the distribution, use and disposal of the end product are virtually zero.

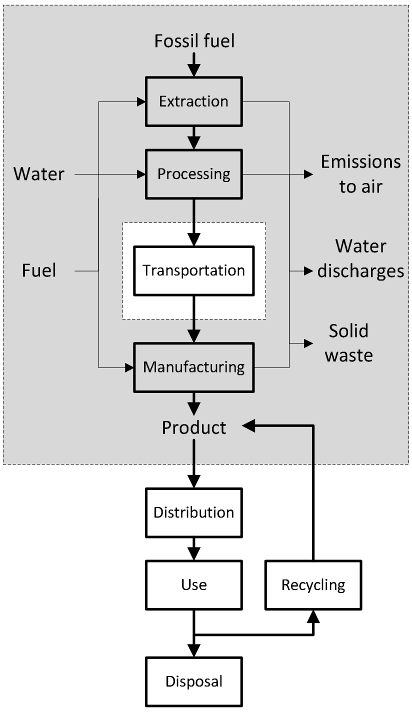


Figure 4.1: The life cycle stages for a given product derived from fossil fuel from cradle to grave.
Note: The items in the shaded area are the items within the system boundary of this analysis.

The methodology has the potential to include environmental and economic impacts from substitution provided these can be quantified under mid-point impact categories or similar indicators.

4.1.2. ENVIRONMENTAL EVALUATION

Environmental data are sourced from Life Cycle Inventories (LCI) that are either average data for a typical process or specific data for an existing process. Material inputs consist of raw materials and energy required by the processes. Material outputs consist of emissions to air, aqueous emissions, and solid emissions produced by the process. The material flow data are reported using a basis of one tonne of product exiting the system. In the case of electricity, the basis is one megawatt-hour (MWh) of net electricity sent-out from the system.

The methodology requires material flow data for natural gas-fed processes as well as the material flow data for alternative feedstocks. To keep the data consistent for a certain sector, life cycle inventories for natural gas and black coal feedstock options should be sourced from the same literature. This is to ensure that the same assumptions and methods are applied to obtain the life cycle inventories of each feedstock option. Parameters such as water usage options (e.g. for cooling) need to be adjusted to a common configuration to maintain consistency and to avoid distortion of the results.

4.1.2.1. EMISSIONS TO AIR

Emissions to air are classified into impact categories according to their known impacts on human health and the quality of ecosystems (EFMA 2000). This study adopts the methodologies and mid-point indicators recommended by the CML 2002 method (Guinée et al. 2002a) to measure the environmental impact factors of each substance. The factors for each category are multiplied with the mass of the substance released per year to obtain the emission impacts per year. This is shown using Equation 4.1.

$$z_k = \sum_a (z_k)_a \times m_a \qquad \text{(Equation 4.1)}$$

where m_a = mass of the substance *a* released annually

$(z_k)_a$ = environmental impact potential of the substance *a*

The air emission substances recorded in this analysis were carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), non-methane volatile organic compounds (VOC), carbon monoxide (CO), nitrogen oxides (NO_x), sulphur dioxide (SO_2), hydrogen sulphide (H_2S) and particulates (PM_{10}). These are categorised into the following impact categories depending on their contribution in the relevant impact are: Global Warming Potential (GWP), Acidification Potential (ADP), Photochemical Oxidation Potential (POP) and Particulate Matter Formation (PMF).

4.1.2.1.1. Global Warming Potential (GWP)

This study follows the model developed by the IPCC (2007) to measure the contribution of different greenhouse gases to global warming using the GWP factor. The factor is expressed as a ratio between the infrared radiative forcing due to the instantaneous emission of 1 kg of a substance and that due to the emission of 1 kg of CO_2. Both of these are integrated over time, hence the GWP factor depends on the time horizon on which the integration is performed. A 100-year time horizon is chosen to provide an indication of long-term effects and reflect future effects of greenhouse gas emissions (DSEWPC 2004). The GWP factors are measured for all substances *a*, which include CO_2, CH_4 and N_2O as the main three greenhouse gases, and added together to form a single indicator based on the GWP equivalence of CO_2 (e.g. t CO_2-eq./t product) as shown in Equation 4.2.

$$GWP = \sum_a GWP_a \times m_a \qquad \text{(Equation 4.2)}$$

4.1.2.1.2. Acidification Potential (ADP)

This study adopts the RAINS-LCA model developed by Alcamo et al. (1991) to calculate the ADP of substances emitted to the air. The acidification indicators consist of characterisation factors representative of Europe which were recommended to be the best available practice for LCA. The Acidification Potential (ADP) factor is defined as the number of H^+ ions produced per kg of substance relative to that produced by 1 kg of SO_2. The average European ADP factors were used for acidifying substances NO_x and SO_2, while alternative generic ADP factors were used for H_2S. The ADP for all substances *a* is calculated using Equation 4.3 and is based on the ADP equivalence of SO_2 (e.g. t SO_2-eq./t product)

$$ADP = \sum_a ADP_a \times m_a \qquad \text{(Equation 4.3)}$$

4.1.2.1.3. Photochemical Oxidation Potential (POP)

The POP is defined by UNECE (1991) as “the potential of an individual VOC relative to that of other VOCs, to form ozone by reaction with oxides of nitrogen in the presence of sunlight”. POP factors for the inorganic substances NO_x and CO were provided by Guinée et al. (2002b), while VOC, which represented non-methane hydrocarbons, was assigned a value of 0.416, which indicated that 0.416 kg of VOC had the same contribution to ozone increment as 1 kg of ethylene (C_2H_2) (Heijungs et al. 1992). Photochemical oxidation is also known as summer smog or secondary air pollution (Guinée et al. 2002b). For this study, the contribution of particles, CO and sulphur compounds to another version of smog known as winter smog is not considered. The POP for all substances *a* is calculated using Equation 4.4 and is based on the POP equivalence of C_2H_2 (e.g. t C_2H_2-eq./t product)

$$POP = \sum_a POP_a \times m_a \qquad \text{(Equation 4.4)}$$

4.1.2.1.4. Particulate matter formation (PMF)

This category considers particulate matter less than 10 micrometres in diameter (PM_{10}) representing a complex mixture of organic and inorganic compounds. This category of particles refers to the coarse particles that consist of non-combustible material released from anthropogenic sources, such as the combustion of fossil fuels. According to WHO (2003), there is a subcategory for fine particles less than 2.5 micrometres ($PM_{2.5}$), which originate from secondarily formed aerosols or produced by the intermediate reactions of gases in the atmosphere. For this analysis, only PM_{10} is measured and the contribution of other substances is omitted from the particulate matter category.

4.1.2.1.5. Characterisation factors

The characterisation factors for emission-to-air substances from Guinée et al. (2002a) are used in this analysis and summarised in Table 4.1.

Table 4.1: CML 2002 method characterisation factors for emission-to-air substances (Guinée et al. 2002b)

Substance	**Global Warming Potential (GWP)**	**Acidification Potential (ADP)**	**Photochemical Oxidation Potential (POP)**	**Particulate matter (PM_{10})**
Units	t CO_2 eq./t substance	t SO_2 eq./t substance	t C_2H_4 eq./ t substance	t PM_{10}
CO_2	1			
CH_4	21		0.006	
N_2O	310			
VOC			0.416	
CO			0.027	
NO_x		0.7	0.028	
SO_2		1		
H_2S		1.88		
PM_{10}				1

4.1.2.2. WATER IMPACTS

Water impacts can be assessed through a water footprint assessment. ISO 14046 (2014) provides principles, requirements and guidelines related to a water footprint assessment which is based on LCA. Impacts related to water degradation or the negative change in water quality are not covered in this study. Two types of water impacts are covered in this analysis: water withdrawal and water discharge. Water withdrawal, according to ISO 14046 (2014), is the “anthropogenic removal of water from any water body or from any drainage basin, either permanently or temporarily”. This category can be divided into freshwater withdrawal impacts and associated water withdrawal impacts.

Freshwater withdrawal (FWW) impacts deal with mostly surface water systems. The freshwater withdrawal potential is an indicator of the amount of water required by the process and its contribution to water depletion to current surface water systems. This category is relevant to both mining and process plants and includes cooling water and steam system makeup. The measurement unit for FWW is ‘t water extracted from freshwater sources/t product’.

Associated water withdrawal (AWW) impacts deal with water that is present with underground fuel resources and is extracted together with the fuel resource. One such example is coal seam water that is extracted as a result of coal seam depressurisation for the CSG to flow to the surface. This category is only applicable for the mining sections. The unit of measure for AWW is ‘t associated water extracted from underground sources/t product’.

For the water discharge category, Saline Water Discharge (SWD) is measured. The main contributors to this category are the blowdown streams from cooling water and steam systems. It can be used to calculate water consumption which, according to ISO 14046 (2014), is often used to describe water removed from, but not returned to, the same drainage basin. Water consumption can be because of evaporation or integration into a product. This is done by taking the difference between water input and water consumption. It also acts as a measure of wastewater produced from a process which requires treatment. The unit of measure for SWD is ‘t saline water discharged/t product’.

4.1.2.3. SOLID WASTE GENERATION (SWG)

The Solid Waste Generation (SWG) category encompasses solid waste generated from the process. This category measures the potential for a process to leave behind a large solid waste footprint prior to recycling and reuse. Recycling and reuse may reduce the volume of solid waste that is ultimately sent away for disposal, but in this analysis, zero recycling and reuse is assumed. Overburden from coal mining and ash from coal processes is included in this category. The unit of measure for SWG is ‘t solid waste generated/t product’.

4.1.2.4. NORMALISATION FACTORS

According to ISO 14044 (ISO 2006b), normalisation is “calculating the magnitude of category indicator results relative to reference information”. In this study, Australia’s emissions to air, water extraction and discharge and solid waste generation at the national level act as the reference information. These are found in Table 4.2 and the data sources and assumptions can be found in Appendix A.1. Normalisation is carried out according to Equation A.1 in Appendix A.1. The impacts in the LCA, expressed in ‘t impacts/t natural gas substituted’ depending on the environmental impact category, are divided by the corresponding Australian annual impacts in units of ‘t impacts/yr’ in Table 4.2. This unifies all environmental impact categories using one common unit ‘yr/t natural gas substituted’, thus allowing comparison of relative magnitudes between sectors and between categories.

Table 4.2: Normalisation factors for environmental impact categories

Category	Units	Value
Global Warming Potential (GWP)	t CO_2-e/yr	5.46E+08
Acidification Potential (ADP)	t SO_2-e/yr	1.71E+06
Photochemical Oxidation Potential (POP)	t C_2H_4-e/yr	1.10E+05
Particulate Matter formation (PMF)	t PM_{10}/yr	8.30E+05
Freshwater withdrawal (FWW)	t/yr	8.23E+10
Associated water withdrawal (AWW)	t/yr	3.13E+08
Saline Water Discharge (SWD)	t/yr	6.28E+10
Solid Waste Generation (SWG)	t/yr	6.19E+07

4.1.3. ECONOMIC EVALUATION

Substitution of natural gas with other alternatives will have economic consequences due to the difference in capital and operating costs. These capital and operating costs are representative of new, greenfield projects with the purpose of replacing existing projects. A baseline project is selected from existing projects in Australia. Where there is no existing project in Australia, a similar project overseas is chosen. Costs originating from different time periods and countries are adjusted to a common basis of 2012 Australian dollars.

The extraction and purification sections are handled separately from the downstream sections. For the upstream section, the capital and operating costs are taken into account to estimate a transfer price for each purified feedstock. This transfer price is used in the downstream manufacturing process as the price paid for the purified feedstock. Transfer prices account for cash operating costs, annualised capital costs and royalties but exclude distribution costs or further profit margins derived from market opportunities.

4.1.3.1. CAPITAL COST

Capital costs are estimated from knowledge of a published cost of a reference plant using the same process technology and of similar scope. The reference plant is selected on the basis of a suitable configuration and level of supporting detail in cost breakdown and assumptions. Adjustments for capacity, inflation and location are nearly always necessary and are performed using Equation 4.5 (Brennan 1998).

Cost inflation indices are required to reflect the changes in plant capital costs with time. In Australia, a composite index based on a 50% weighting of the materials used in buildings other than houses and a 50% weighting of average weekly earnings (ordinary time earnings for full-time adults) is used (Brennan 1998). A list of plant cost inflation indices from 1981 to 2012 are included in Appendix A.2.

The location factor *L* is the ratio of the cost of a plant built in the proposed location to the cost of an identical plant built in the reference plant location. If the two locations are from different countries, the currency exchange rate must be used. Historical currency rates used to adjust U.S. costs or European costs to Australian costs ranging from 2003 to 2012 are included in Appendix A.3.

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad \text{(Equation 4.5)}$$

where I = fixed capital investment
Q = production capacity of plant
F = inflation index
L = location factor
b = capacity exponent
p = proposed plant
r = reference plant

For a plant, economies of scale exist when the capital investment per unit of production capacity decreases with increasing production capacity. These scale economies encourage investment into larger capacities at both equipment and plant levels (Brennan 2012). Scale of economies need to be factored in when scale adjustments are made and is reflected by the exponent *b* in Equation 4.5. Where no scale exponent is given, the default value for *b* was assumed to be 0.7.

4.1.3.2. OPERATING COST

Total operating costs are the sum of the annualised capital cost and the cash operating cost as shown in Equation 4.6. The capital costs are accounted for as annualised capital costs over the operating life of the system. The cash operating costs consist of feedstock and utility costs, wages, fixed operating costs and administrative, research and marketing costs, to obtain total operating costs. Cash operating costs are calculated using a conventional operating cost model, using data based on the literature for technology performance and supported by cost assumptions.

$$\text{Total operating cost} = \sum \left(\text{Annualised capital cost} + \text{Cash operating cost} \right) \qquad \text{(Equation 4.6)}$$

4.1.3.2.1. Annualised capital cost

The annualised capital costs are calculated using Equation 4.7. The fixed capital investment I_p is obtained from Equation 4.5.

$$A = I_p \left(\frac{i(1+i)^n}{(1+i)^n + 1} \right) \qquad \text{(Equation 4.7)}$$

where A = annualised capital cost
I_p = fixed capital investment of proposed plant
i = discount rate
n = plant life

The U.S. Department of Energy used a real after-tax discount rate of 10% when estimating the cost of natural gas and black coal power plants (NETL 2010b, 2012). Bedilion et al. (2009) reported a discount rate in the range of 9.2% to 11.1% in an Electric Power Research Institute (EPRI) report assessing the costs of electricity generation technologies in Australia. Hence, a discount rate of 10% was assumed for all plants in this study, including processing plants in both the upstream and downstream section. Bedilion et al. (2009) also assumed a plant life of 30 years for all power plants in the study. This same assumption was made for all plants in this study. The discount rate i and plant life n are summarised in Table 4.3.

Table 4.3: Annualised capital cost assumptions

Item	**Value**	**Units**
Discount rate, i	10	%/year
Plant life, n	30	years

4.1.3.2.2. Cash operating cost

The cash operating costs is dictated by a number of cost components such as:

- Plant capacity factor, which is the percentage of its full capacity at which the plant operates per year.
- Payroll overheads, which include additional costs incurred by the employer apart from wages and salaries. These include workers' compensation premiums, leave, payroll tax and pension contributions.
- Supervision of process labour

- Maintenance costs, which consist of maintenance labour and materials costs for plant equipment, buildings, piping and instrumentation. Costs for maintenance labour are often assumed to be equal to the cost of maintenance materials (Brennan 1998, Mussatti & Vatavuk 2002).
- Consumables, or operating supplies, which include protective clothing for operators and supervisory personnel, lubricants, charts, test chemicals and custodial supplies.
- Plant overheads, which include the costs of operational staff (e.g. engineers, accountants, clerical, administrative, plant management) as well as costs for providing services for medical, cafeteria, vehicles and stores.
- Laboratory costs, which include laboratory staff, analytical equipment maintenance, reagents
- Property insurance, which is required to protect the facility in the event of accidents or external damages.
- Property taxes, which are usually dependent on the locality of the facility and regional laws.
- Administrative costs, which are part of non-manufacturing costs and include wages for personnel who direct and advise the company (e.g. management, public relations, finance and corporate planning) as well as costs for supplies, equipment, communications and buildings for administrative and legal activities.
- Marketing costs, or selling expenses, which are incurred in the selling of the product
- Research and development, which incorporate laboratory and pilot-scale plant costs for new and improved technologies.

The cash operating cost assumptions and their values used in the analysis are summarised in Table 4.4. The values were chosen based on recommendations in Brennan (1998) and Peters et al. (2003), which can be found in Appendix A.4.

Table 4.4: Cash operating cost assumptions

Item	**Value**	**Units**
Availability	85	%
Number of shift teams	5	-
Payroll overheads (PO)	40	% OL [a]
Supervision	15	% (OL+PO) [b]
Maintenance and repairs	2	% FC [c]
Consumables	10	% (OL+PO) [b]
Plant overheads	100	% (OL+PO) [b]
Laboratory	10	% (OL+PO) [b]
Insurance	1	% FC [c]
Property taxes	1	% FC [c]
Administrative costs	4	% PC [d] for stand-alone plants
	2	% PC [d] for integrated plants
Marketing costs	5	% PC [d] for standalone plants
	2	% PC [d] for integrated plants
Research and development costs	5	% PC [d] for standalone plants
	2	% PC [d] for integrated plants (utility and chemicals)
	1	% PC [d] for integrated plants (utility only)

[a] OL, operating labour = number of process operators per shift x number of shift teams x annual wages

[b] OL+PO = ∑(operating labour and payroll overheads)

[c] FC, fixed cost = % of plant capital cost

[d] PC, production costs = % of total operating cost

4.1.3.2.3. Upstream operating costs

The upstream operating cost of a fossil fuel process, which includes the extraction and purification stages, consists of the annualised capital cost, cash operating cost and an additional royalty cost. Royalties are paid to the owners of fossil fuel resources, and are integrated into the transfer price of the feedstock. Royalties are calculated as a percentage of the value of production (total revenue less allowable deductions). Based on royalty rates on coal and petroleum levied in Western Australia, New South Wales, and Queensland, an average royalty rate of 7% of the transfer price was chosen for all coal upstream systems and 11% was chosen for all gas upstream systems (Department of Mines and Petroleum (Government of Western Australia) 2013, Division of Resources and Energy (New South Wales Government) 2013, Queensland Treasury and Trade (Queensland Government) 2013). Table 4.5 summarises the royalty rates chosen for natural gas and coal.

Table 4.5: Average royalty rates for coal and petroleum in Australia

Item	**Value**	**Units**
Coal royalty rate	7	% of transfer price
Petroleum royalty rate (for conventional gas or CSG)	11	% of transfer price

Royalty costs are calculated using Equation 4.8, where total operating costs are the sum of the annualised capital cost and cash operating cost as calculated in Equation 4.6..

$$\text{Royalty cost} = \text{Total operating cost} \times \left(\frac{\text{Royalty rate}(\%)}{100\% - \text{Royalty rate}(\%)} \right) \qquad (\text{Equation 4.8})$$

The upstream operating cost of fossil fuels is also referred to as the transfer price that is paid by the downstream manufacturing plants. This is either expressed in $ per tonne processed resource (weight basis) or $ per GJ-HHV (energy basis).

4.1.3.2.4. Labour and utility costs

Table 4.6 shows the costs of labour based on different industry sectors and the costs of utilities used in the analysis. Labour costs were adapted from the Australian Bureau of Statistics (ABS 2012a, b) and are located in Appendix A.5. The costs of recirculated cooling water are obtained through calculations and are detailed in Appendix A.5. It was assumed that process water and boiler feedwater make-up have the same cost. Costs for sulphur and oxygen were reported by Brennan (1998) to be \$55/t and \$80/t in 1996 U.S. dollars. These costs were adjusted to 2012 Australian dollars using the plant cost indices from Appendix A.2 and currency exchange data from Appendix A.3.

Table 4.6: Uabour and tility costs (Cost are expressed in 2012A\$)

Labour costs			
Sector	**Wages and salaries per employee**	**Units**	**Reference**
Gas supply	107,000	\$/yr	ABS 2012a
Electricity	110,000	\$/yr	ABS 2012a
Mining	119,000	\$/yr	ABS 2012a
Chemical manufacturing	87,000	\$/yr	ABS 2012a,b
Metal manufacturing	82,000	\$/yr	ABS 2012a,b
Utility cost			
Item	**Value**	**Units**	**Reference**
Recirculated cooling water	0.077	A\$/m^3	Appendix A.5
Cooling water makeup	1.00	A\$/t	Appendix A.5
Boiler feedwater makeup	1.50	A\$/t	
Sulphur	82	A\$/t	(Brennan 1998)
Oxygen	119	A\$/t	(Brennan 1998)

4.1.4. FOSSIL FUEL PROPERTIES

The energy content of the fossil fuels will affect the life cycle inventories and costs of fossil fuels when the values are converted from an energy basis to mass basis and vice versa. For this analysis, the energy content and composition of the fossil fuels are kept consistent for each downstream case.

The black coal energy content and composition are adapted from AGO (2006) as shown in Table 4.7. For black coal, the medium-ash, low to medium volatile domestic coal was chosen. It is representative of coal from Hunter Valley, which has a Higher Heating Value (HHV) of 24.4 GJ/t.

Table 4.7: Coal analysis of Australian reference coal (AGO 2006)

Proximate analysis (wt%)			
	As received	**Dry**	**Dry, ash-free**
Moisture	7.5	0	0
Ash	21.2	22.9	0
Volatile matter	29.2	31.6	41.0
Fixed carbon	42.1	45.5	59.0
Total	100	100	100
Ultimate analysis (wt%)			
	As received	**Dry**	**Dry, ash-free**
Moisture	7.5	0	0
Ash	21.2	22.9	0
Carbon	60.1	65.0	84.3
Hydrogen	3.8	4.1	5.3
Nitrogen	1.3	1.4	1.8
Sulphur	0.4	0.5	0.6
Oxygen	5.6	6.1	7.9
Total	100	100	100
Heating value			
Higher heating value (GJ/t-HHV)	24.4		

The natural gas energy content and composition as received from the pipeline are adapted from AGO (2006) as shown in Table 4.8. CSG is assumed to have the same energy content and composition as natural gas when received at the pipeline. The concentration of sulphur in natural gas is adapted from DSEWPC (2011) and is assumed to be the average for Australia. Dividing the gross calorific value of natural gas with the density, both of which can be found in Table 4.8, gives the HHV of the natural gas, which is 51.3 GJ/t-HHV.

Table 4.8: Pipeline natural gas properties (AGO 2006, DSEWPC 2011)

Base pressure (bar, absolute)	100
Base temperature (°C)	15
Specific gravity	0.6185
Gross calorific value (MJ/Sm^3)	38.91
Net calorific value (MJ/Sm^3)	35.11
Density (kg/Sm^3)	0.7579
Wobbe Index (MJ/Sm^3)	49.48
Sulphur concentration (mg/m^3)	8.4
Composition (mol%)	
Methane	90.91
Ethane	4.50
Propane	1.04
n-Butane	0.21
i-Butane	0.13
Helium	0.04
Nitrogen	1.11
Carbon dioxide	2.06

The industrial diesel fuel heating value of 44.9 GJ/t-HHV adapted from Penney et al. (2012) was used for diesel calculations in the analysis. The diesel was assumed to have 0.05 wt% sulphur.

4.1.5. OTHER ASSUMPTIONS

The average ambient air conditions for Australia used throughout the study were adopted from AGO (2006). These are:

- Dry bulb temperature = 25°C
- Wet bulb temperature = 19.45°C
- Relative humidity = 60%
- Pressure = 1 bar absolute
- Equivalent altitude = 111 m

In order for all downstream plants to be compared on the same basis in terms of freshwater withdrawal, it is assumed that all plants utilise recirculated cooling water, together with a mechanical draft, evaporative cooling tower. This was favoured over once-through cooling because of its lower water requirements. Dry cooling systems (e.g. air cooling with fans) can further reduce water consumption and is applicable for plants located inland, but they were not chosen because they consume more electricity per unit of cooling compared to recirculated water cooling systems, which has the effect of reducing the sent-out efficiency and increasing the carbon dioxide emissions of electricity generation plants (Smart & Aspinall 2009).

4.2. UPSTREAM EXTRACTION AND PURIFICATION

4.2.1. OVERVIEW

The upstream section consists of the extraction and the purification stage. The upstream section is where raw material acquisition occurs in order to supply the resources required by the downstream process. In most LCAs, the resource flows down a single pathway from extraction to final use, but in a system-wide resource network, the resource leaving the upstream section may branch out into multiple downstream sections, each with its own environmental and economic impacts. Figure 4.2 shows that for cases examining a single fuel type for multiple downstream uses, it was assumed that all downstream sectors share the same upstream section.

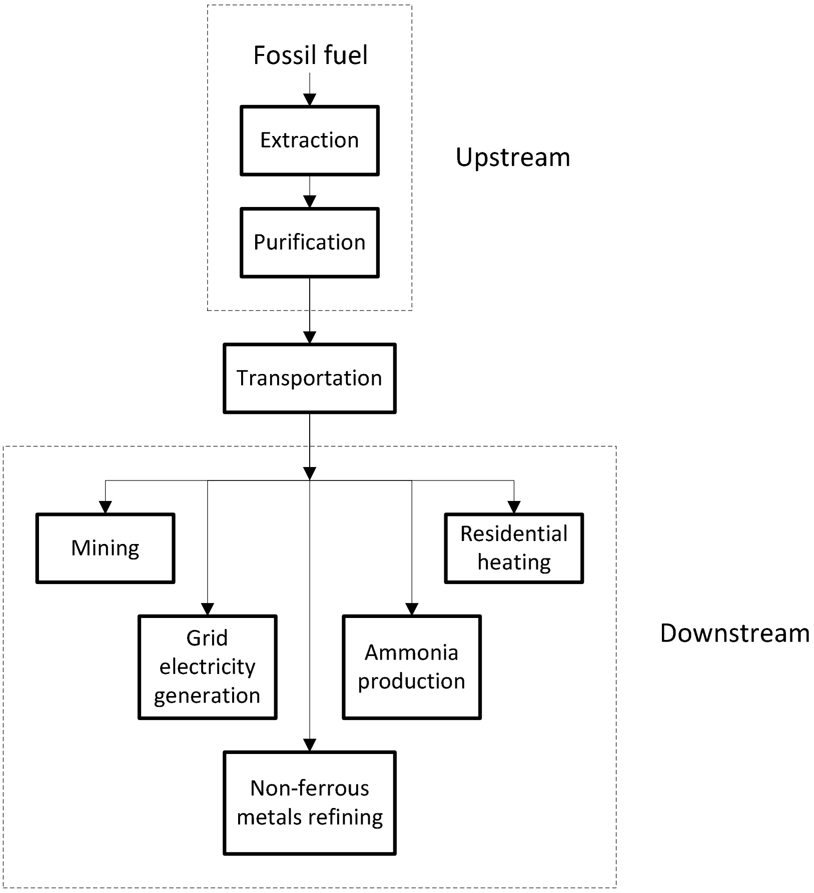


Figure 4.2: Flow diagram showing the upstream and downstream sections of a fossil fuel network.
Note: The downstream sectors listed are among the sectors studied as part of the natural gas network.

The fossil fuels covered in this chapter will include natural gas, black coal, CSG and diesel. The chapter will present environmental and economic data for each fossil fuel type and analyse the substitution impacts in the upstream section when natural gas is replaced with black coal, CSG or diesel. In particular, the economic data will be reported in the form of a transfer price for each fossil fuel. The transfer price is the sum of annualised capital costs, cash operating costs and an additional royalty rate, and is used to represent fuel costs in the calculation of operating costs for downstream processes.

4.2.2. NATURAL GAS

4.2.2.1. INTRODUCTION

Conventional natural gas refers to the gas resource accumulated in a subsurface reservoir that can be extracted using traditional methods (e.g. drilling and allowing gas to flow up the well). Due to the porosity of the geological layer there are generally only a few wells required for each basin (Department of Environment and Heritage Protection 2013). Conventional natural gas that is found together with oil is called associated gas.

92 per cent of Australia’s conventional gas resources are located offshore in the Carnavon, Browse and Bonaparte basins off the north-west coast (Geoscience Australia & BREE 2014). There are also offshore resources off the south-east coast of Australia (e.g. Otway, Bass and Gippsland basins) and off the west coast of Australia (e.g. Perth basin). The onshore gas basins in Australia are generally smaller and most are past their peak production (e.g. Amadeus, Cooper/Eromanga/Warburton, and Bowen/Surat basins) Adavale, Bowen, Surat, Clarence-Moreton and Gunnedah basins) Australia’s economic demonstrated resources and sub-economic demonstrated resources of conventional gas were recently estimated at 157 trillion cubic feet or 2,918 billion cubic metres (Geoscience Australia 2012, BREE 2013f). The locations of these conventional gas resources and their respective quantities are shown in Figure 4.3.

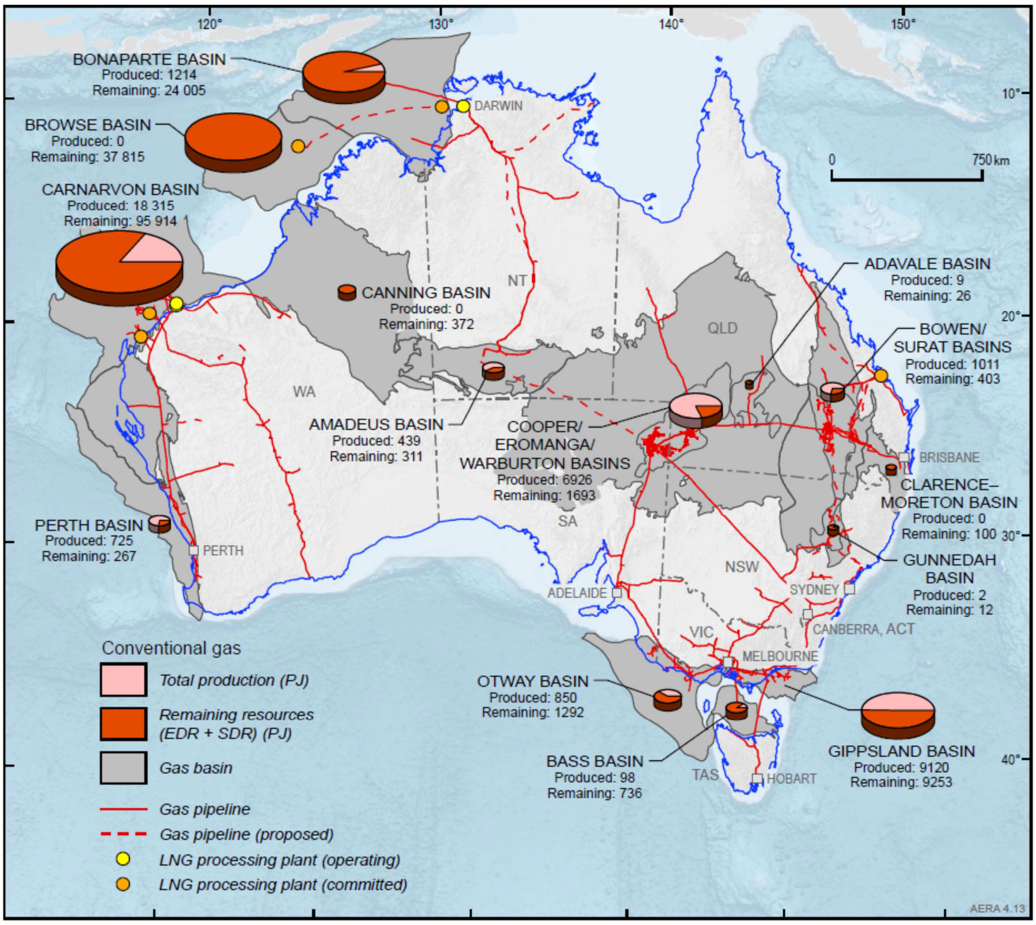


Figure 4.3: Location of Australia’s natural gas reserves and infratructure, excluding those related to CSG (Geoscience Australia & BREE 2014)

4.2.2.2. EXTRACTION AND PURIFICATION

As most of Australia’s natural gas resources are located offshore, it can be assumed that the whole upstream extraction and purification of natural gas can be adequately represented by modelling an offshore extraction well and onshore processing plant.

The offshore conventional gas extraction facilities gather conventional gas and accompanying hydrocarbons, liquids and gases from the wells on the seabed and deliver it to the onshore gas processing plant. Subsea manifolds are installed on the seabed, and development wells are drilled from the subsea trees clustered around the manifolds to extract the gas from underground reservoirs. Some large production facilities have offshore processing platforms with phase separation, compression and dehydration equipment with on-board living quarters.

Typically, the raw natural gas extracted at the wellhead needs to be conditioned so that it can be transported to the gas processing plant. Scrubbers remove solids and impurities such as sand and other large particles, and heaters ensure the temperature of the natural gas does not drop too low and form hydrates with the water vapour content of the gas stream. For wellheads located offshore, chemicals such as ethylene glycol are added to the gas stream at the wellhead so that hydrate formation is avoided as the gas stream is transported through the underwater pipeline to the shore. Once onshore, the chemicals are then separated from the gas and recycled. Natural gas hydrates are crystalline ice-like solids that can impede the passage of natural gas through pipes and valves.

Upstream gas processing involves a series of processes to remove impurities from raw natural gas. These are covered in detail by Kidnay and Parrish (2006), EIA (2006) and Gary et al. (2007). The process steps of a typical gas processing plant are shown in Figure 4.4.

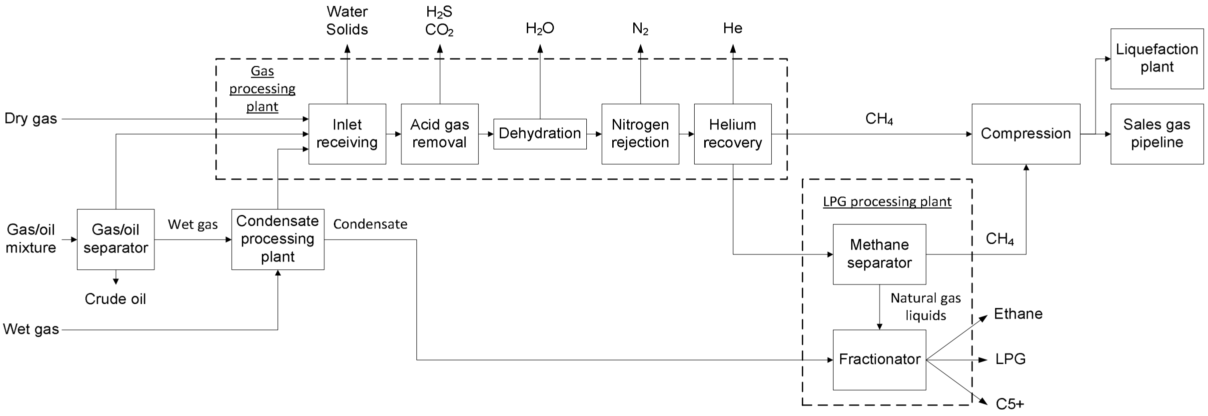


Figure 4.4: Possible pathways for natural gas processing

Gas processing plants involve a series of processes to remove impurities from raw natural gas. The process steps used depends on the natural gas source and composition. The main processes in natural gas processing are:

- Gas/oil separator (associated gas) – This process is used to separate gas from oil, either by using gravity separation in a conventional closed tank or with alternate heating and compressive cooling in a multi-stage gas-oil separation process.
- Condensate separator (wet gas) – Condensates are often removed from the gas stream at the wellhead using mechanical separators. Prior to this step, the gas enters through an inlet slug catcher to remove free water and solids. The condensate is then routed to the liquids handling section.

- Gas sweetening – A gas treatment step is required to remove acid gases such as hydrogen sulphide (H_2S) and carbon dioxide (CO_2). Both gases form a weak, corrosive acid in the presence of water. Carbonyl sulphide (COS) can also be formed during regeneration of molecular sieve beds used in dehydration. The most commonly used method is a two-step amine absorption system. H_2S and CO_2 are removed from the gas by absorption into the amine solution, and then stripped from the solution by steam generated in a reboiler. The lean solution is cooled and returned to the top of the absorber.
- Dehydration – Water which may potentially form hydrates is eliminated using an ethylene glycol absorption system or adsorption dry-bed dehydrator towers which contain desiccants such as silica gel and activated alumina.
- Nitrogen/helium extraction – Nitrogen removal is either performed by cryogenically separating the nitrogen and venting it to the atmosphere, or using an absorbent solvent to separate methane and heavier hydrocarbons from nitrogen. Helium can be extracted from the gas stream in a Pressure Swing Adsorption (PSA) unit.
- Methane separation – Methane can be recovered either by cryogenic processing, where a turbo expander condenses the heavier hydrocarbons and leaves methane in gaseous form, or passing through a solution which absorbs the natural gas liquids from the methane. These natural gas liquids are then removed from the absorption solution and directed to the fractionator.
- Fractionation – The natural gas liquids are separated using the respective boiling points of the individual hydrocarbons in the stream.

The natural gas, mostly methane, is then compressed to meet sales gas pipeline specifications. The natural gas is then piped to domestic customers, or delivered to a liquefaction plant to be processed for export.

Raw natural gas compositions will vary in different locations across Australia. Brennan (2012) presents three different wellhead gas compositions to demonstrate the range of variability in Australia’s natural gas resources in Table 4.9. Each will have different processing requirements to bring it to a uniform pipeline quality. Variations in composition, as well as other factors such as accessibility and technology will result in variations of environmental impacts and costs in extraction and purification. A sensitivity analysis was performed in Chapter 5.6 to analyse the effects of different wellhead natural gas compositions and extraction costs.

Table 4.9: Wellhead composition of natural gas in different locations across Australia (Brennan 2012)

Location	Ballera	Timor Sea	Bass Strait
Pressure (kPag)	8,000	31,000	7,000
Temperature (°C)	60	135	23
Composition (mol%)			
Methane	62	71	80
Ethane	10	7.4	7
Propane	3.7	4.6	4.4
i-Butane	0.6	1.2	0.9
n-Butane	1.1	1.7	1.2
i-Pentane	0.3	0.8	0.6
n-Pentane	0.4	0.6	0.6
C6+	2.6	4.1	2.3
N2	1.6	3.4	0.7
CO2	17.9	5.5	2.1
Total	100	100	100
Water	Saturated	Saturated	Saturated
Hydrogen sulphide	30 ppm	20 ppm	60 ppm

4.2.2.3. MATERIAL FLOWS

The material flows for the conventional natural gas upstream system were adapted from May (2003). These were based on inventory data for petroleum extraction (fuel usage/inputs and petroleum product outputs) gathered from APPEA, which represented 98% of Australia's oil and gas industry. Natural gas is separated from the other petroleum products in the processing stage. The data were reported on the basis of the production of one t mixed petroleum products from an average well. The material flow data from May (2003) is located in Appendix A.6.

Allocation was required to divide the environmental impacts between natural gas and the rest of the petroleum products. May (2003) used an allocation factor to convert to the basis of one tonne of natural gas as shown in Equation 4.9.

$$\frac{\text{Impacts}}{\text{t natural gas}} = \frac{\text{Impacts}}{\text{t mixed petroleum product}} \times 0.758 \left(\frac{\text{t mixed petroleum product}}{\text{t natural gas}} \right) \qquad (\text{Equation 4.9})$$

The environmental impacts of the extraction and purification of conventional natural gas is summarised in Table 4.10. A portion of natural gas was consumed for delivery, heat and electricity generation for internal use, and lost through flaring and leaking.

Table 4.10: Material flow data for the production of 1 tonne dry natural gas (no petroleum liquids)

Inventory data	Units	Values	Category
Input			
Natural gas	t/t natural gas	4.41E-02	Fuel
Cooling water makeup	t/t natural gas	2.88E-01	Freshwater Withdrawal
Produced water	t/t natural gas	4.90E-01	Associated Water Withdrawal
Output			
Natural gas	t/t natural gas	1.00	Product
Cooling water blowdown	t/t natural gas	4.51E-02	Saline Water Generation
Produced water	t/t natural gas	4.90E-01	Associated Water Withdrawal
CO_2	t/t natural gas	2.55E-01	Global Warming Potential
CH_4	t/t natural gas	2.70E-03	Global Warming Potential
N_2O	t/t natural gas	1.41E-05	Global Warming Potential
VOC	t/t natural gas	1.02E-03	Photochemical Oxidation Potential
CO	t/t natural gas	4.50E-04	Photochemical Oxidation Potential
NO_x	t/t natural gas	1.61E-03	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t natural gas	1.48E-04	Acidification Potential
H_2S	t/t natural gas	3.18E-11	Acidification Potential
PM_{10}	t/t natural gas	7.73E-05	Particulate Matter Formation

The environmental data may vary depending on the location and composition of the conventional natural gas resource. For example, the sensitivity analysis in Chapter 5 showed that the variability of CO_2 in raw natural gas will affect the CO_2 emissions of the gas processing plant.

When compared with U.S. data on domestic and foreign offshore natural gas extraction and purification, the Australian emissions were found to be generally higher (see Appendix A.7).

4.2.2.4. CAPITAL COSTS

Existing conventional natural gas projects were analysed to select one with a suitable capacity and configuration and with sufficient cost data to represent natural gas extraction and purification as a whole. The capital costs of five different offshore projects with both an offshore extraction component and an onshore processing component are plotted against the annual capacity in PJ/yr (Figure 4.5). The capital costs and capacities of these projects are located in Appendix A.8.

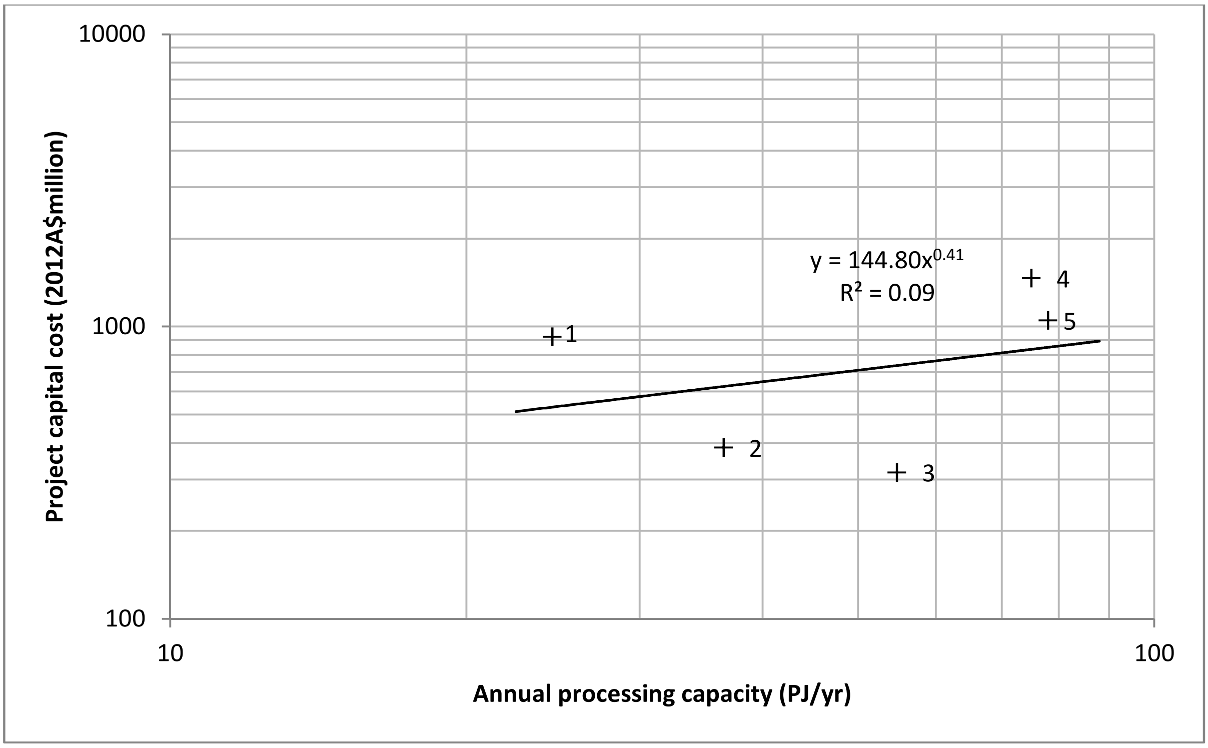


Figure 4.5: Fixed capital investment of natural gas offshore extraction and onshore processing projects in 2012 Australian dollars as a function of capacity in PJ/yr.

Note: The projects included in the diagram are (1) BassGas (2) Longtom (3) Minerva (4) Otway (5) Reindeer/Devil Creek.

The cost trendline for Figure 4.5 follows Equation 4.10:

$$I = 145Q^{0.41} \qquad \text{(Equation 4.10)}$$

where I = fixed capital investment in 2012 Australian dollars
Q = project capacity in petajoules per year (in PJ/yr).

As seen in Figure 4.5, there is a large scatter in the capital costs of offshore natural gas extraction and purification. This is due to many factors such as the different depths and distances from shore of the projects, ocean and land environments surrounding the projects and composition of the gas resource.

The BassGas project, the Otway project and the Reindeer/Devil Creek project (labelled as project 1, 4 and 5 respectively) lie above the cost trendline. These three projects produce liquefied petroleum gases (LPG) and condensate in addition to conventional natural gas. Therefore, the majority of their capital costs can be attributed to the liquids separation and handling infrastructure, thus giving them a fixed capital investment that is higher than average. On the other hand, the Longtom project and the

Minerva project (labelled as project 2 and 3 respectively) fall below the trendline. The Longtom project produces dry gas with no liquids, which gives it a fixed capital investment that is lower than average. The Minerva project produces condensate as well as conventional natural gas, but the project is located in shallow waters and is a relatively short distance from the shore as compared to the other offshore gas projects, giving it a low fixed capital investment.

The distance of the project from shore is also provided for each of the five conventional gas projects. It is assumed that the water depth increases with the distance from shore. This assumption was also made by the U.S. EIA (2010). The capital costs of these projects are plotted against the distance from shore as seen in Figure 4.6.

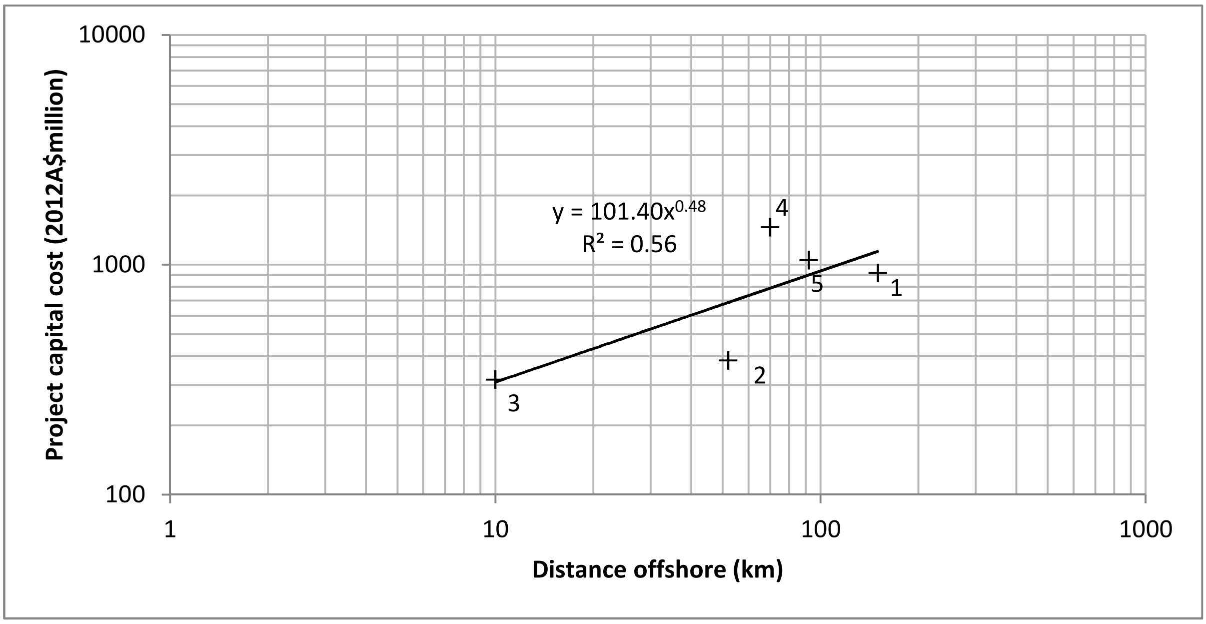


Figure 4.6: Cost of natural gas mining projects in 2012 Australian dollars as a function of distance offshore in kilometres.

Note: The projects included in the diagram are (1) BassGas (2) Longtom (3) Minerva (4) Otway (5) Reindeer/Devil Creek.

When project capital costs are plotted against distance from shore in Figure 4.6, a small correlation can be seen through the cost trendline which follows Equation 4.11.

$$I = 101D^{0.48} \qquad \text{(Equation 4.11)}$$

where I = fixed capital investment in 2012 Australian dollars
D = distance of the project from shore in kilometres.

The Longtom project (2) does not have any liquids handling and falls below the cost trendline. The Otway project (5) lies above the trendline; it involves liquid handling and also includes an expansion linking an additional wellhead to the existing infrastructure. Once again, the Reindeer field and Devil Creek gas processing plant lies close to the cost trendline.

The Reindeer field/Devil Creek project (5) lies the closest to the cost trendline among the five conventional gas projects in Figure 4.5. Therefore, the offshore Reindeer field linked to the onshore Devil Creek gas processing plant jointly owned by Apache and Santos is chosen as the basis to calculate the capital cost for the natural gas upstream stage. This project is representative of a greenfield project with offshore wells, pipelines and onshore processing plant. BREE (2012) was completed at $1.05 billion in Australian dollars with a gas processing component capacity of 78 petajoules per year. The gas processing plant, representing the purification section was quoted to be $276 million after adjustment to 2012 Australian dollars (Lawrence 2010). The gas processing plant has a capacity of 215 TJ/day. Given that the total cost of the project (extraction and purification) was $1.05 billion, the extraction section (offshore wells and pipelines) was calculated to be $774 million in Australian dollars.

4.2.2.5. OPERATING COSTS

The operating costs were divided into the extraction section and the purification section. The operating costs of the extraction section covers the production costs of natural gas from offshore wells, while the purification section covers the operating costs of the onshore natural gas processing plant.

The operating costs of the extraction section was calculated based on U.S. Gulf of Mexico wellhead operating performance as reported by the U.S. Energy Information Administration (EIA) (2010). A value of $48.40 per tonne of natural gas product was calculated for the operating cost of the extraction stage. The detailed calculations are given in Appendix A.9.

The operating costs of the purification section are modelled after an onshore gas processing plant using the operating cost model as shown in Table 4.11. A value of $24.80 per tonne of natural gas product was calculated for the operating cost of the purification stage.

Variations in operating costs may occur if there is a change in capital costs, complexity, fixed costs or utility costs.

Table 4.11: Cash operating costs for natural gas purification plant (Costs are expressed in 2012A$)

Plant capacity		215	TJ/day		
Plant availability		85%			
Annual actual production		1,299,275	t/yr		
Fixed capital investment		276	$ million		
Capital exponent,ψ (I=αQψ)		0.7			
Cost year		2011	AUD$		
Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/t NG)**
Raw materials		Unit usage (/t NG)	Unit cost ($/unit)		
Natural gas feedstock	t	-	-	-	-
Utilities		Unit usage (/t NG)	Unit cost ($/unit)		
Electricity	MWh	0.101	70.00	9.15	7.04
Cooling water	t	32.3	0.08	3.23	2.48
Total variable costs				**12.38**	**9.52**
Operating labour		No.	Salary ($/yr)		
Operators/shift		3			
Shift teams		5			
Total shift operators		15	107,000	1.61	1.24
Total operating labour costs				**1.61**	**1.24**
Payroll overheads		40	% total operating labour cost	**0.64**	0.49
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.34	0.26
Maintenance labour		1		2.76	2.12
Maintenance materials		1		2.76	2.12
Consumables store			10	0.22	0.17
Plant overheads			100	2.25	1.73
Laboratory			10	0.22	0.17
Insurance		1		2.76	2.12
Property taxes		1		2.76	2.12
Total fixed costs				**16.32**	**12.56**
Total manufacturing costs				**28.70**	**22.08**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	1.29	**0.99**
Marketing costs		5	Total production cost	1.61	**1.24**
Research and development costs		2	Total production cost	0.64	**0.50**
Non-manufacturing costs				**3.55**	**2.73**
Total product cost				**32.25**	**24.81**

4.2.2.6. TRANSFER PRICE

The transfer price of natural gas is calculated by adding the annualised capital cost, the cash operating cost, and the royalty rate for the petroleum resource. Table 4.12 shows the transfer price to be A$179 per tonne natural gas, or A$3.48 per GJ in higher heating units.

Table 4.12: Economic flows of a baseline natural gas extraction and purification project (Costs are expressed in 2012A$).

Product output	1.30x10^6 t/year		
Upstream section	Extraction	Purification	Total
Capital costs (A$million)	774	276	1,050
Annualised capital costs (A$/t)	63.2	22.5	85.7
Cash operating costs (A$/t)	48.4	24.8	73.3
Total operating costs (A$/t)	159		
Royalty costs (A$/t)	19.6		
Transfer price (A$/t)	179		
Transfer price (A$/GJ-HHV)	3.48		

4.2.3. BLACK COAL

4.2.3.1. INTRODUCTION

As at 31 December 2008, Australia's economic demonstrated resources of black coal was recorded at 39.2 Gt (Geoscience Australia & BREE 2014). Queensland and New South Wales have the largest shares of these resources with 56% and 40% of the total respectively and are also the largest producing states in Australia (Geoscience Australia & BREE 2014). Figure 4.7 shows the location and quantities of coal reserves in Australia. At a rate of production of 421 Mt per year (2007-2008 production rate), this gives an EDR resource life of approximately 93 years (Geoscience Australia & BREE 2014).

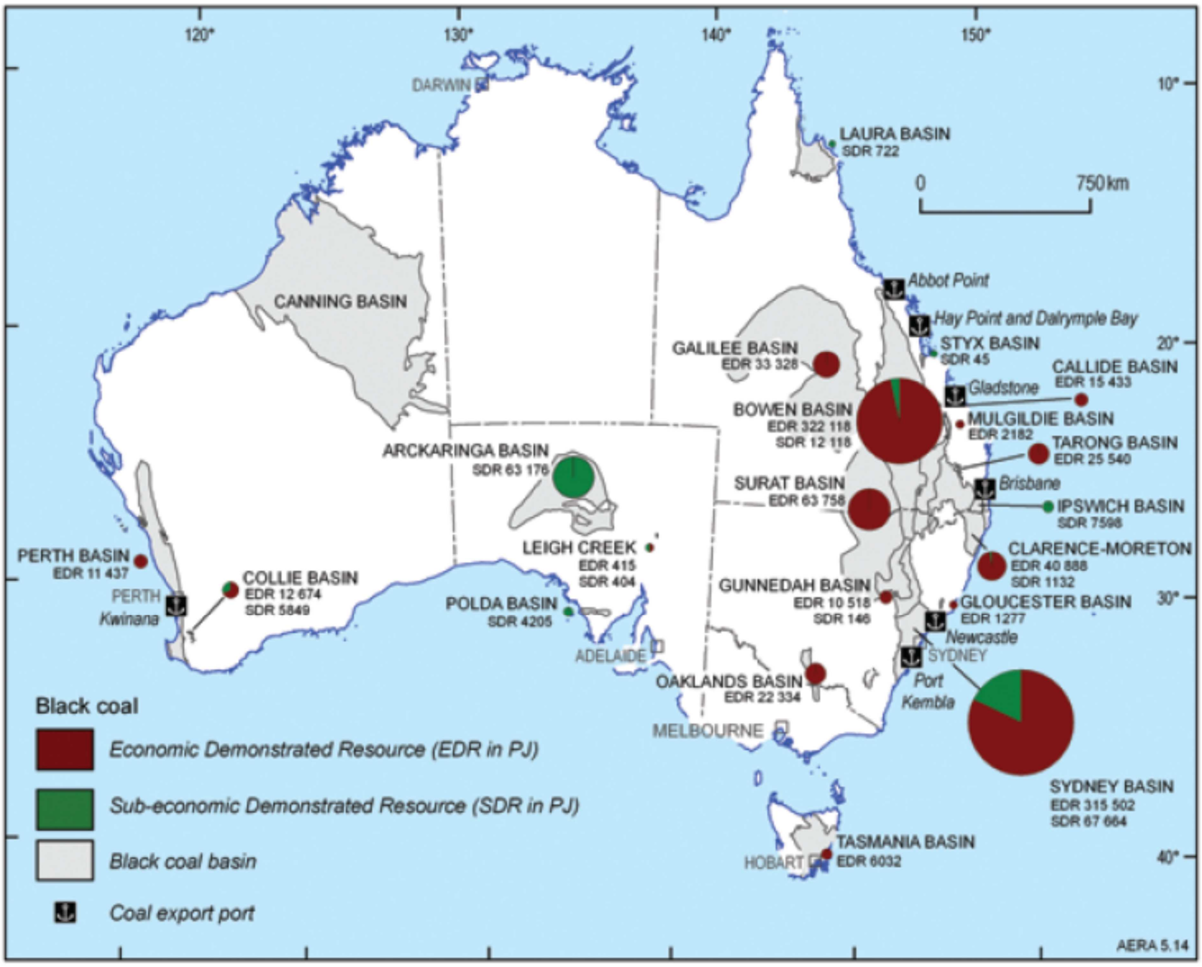


Figure 4.7: Australia's black coal reserves (Geoscience Australia & BREE 2014).
Note: The figure shows the amount of black coal resources extracted and reserves remaining for each basin, brown coal excluded)

Black coal is mined by both surface (or open-cut) mining and underground mining. Approximately 80% of Australia's coal is produced from open-cut mines (Huleatt 2013). Open-cut mining has lower operating costs and generally recovers a higher proportion of the coal deposit than underground mining (typically 90 per cent). Modern large open-cut mines can cover many square kilometres in area and commonly use large draglines to remove the overburden and bucket wheel excavators and conveyor belts to transport the coal. Rosewarne (2012) reported 315 km^2 of the Upper Hunter Valley are open-cut mines. When considering the environmental impacts and costs of the black coal upstream system, the open-cut mine has been chosen to represent the system as the majority of black coal comes from open-cut mines.

Black coal may be used without any processing other than crushing and screening to reduce the coal to a usable and consistent size and remove some contaminants. Coal for export is generally washed to remove pieces of rock or mineral which may be present and later dewatered for efficient transport and use. This lowers the ash content and increases the overall energy content. The coal is then transported by conveyor or rail to power stations for domestic electricity generation or via rail to coal export terminals. For this analysis on domestic use, the export option is not considered.

For this analysis, the black coal upstream section will be represented by an open-cut mine model as the majority of black coal mines are open-cut. Since the analysis focuses on the domestic case, material flows related to the export and the railway connecting the mine to the port are not considered in the analysis.

4.2.3.2. MATERIAL FLOWS

May (2003) presented data for underground and surface black coal mines in Australia and makes the distinction between total coal and coal used for power generation only. The analysis only uses data for the surface black coal mines. It also includes all coal including that used for power generation as the analysis looks at other alternative coal usages such as manufacturing chemicals through coal gasification. A summary of the environmental impacts of open-cut black coal mining is found in Table 4.13.

According to May (2003), the usage of diesel and petrol are the sole contributors to the emissions to air. Each emission to air in the black coal upstream section, e.g. CO_2 is calculated by multiplying the diesel and petrol consumption rate with the emission factor.

Several omissions were made in May (2003) and similarly considered for the current analysis:

- Dust emissions due to blasting, movement and transport were excluded given that they are difficult to measure.
- Seepage of water used in dust prevention and extracted from aquifers through the surface of black coal mines was excluded.
- Artesian water is removed from aquifers to reduce the water table around the mine to below its new surface for surface mines, and removed from inside underground mines, to limit the possibility of flooding. In May (2003), artesian water extraction was recorded for underground mines but for surface mines this was assumed to be negligible.
- Lubricant usage in the maintenance of mining equipment and grease emissions were omitted.
- Explosives usage was recorded in May (2003), but was not considered in the current analysis.
- Limestone, which is applied to underground surfaces to reduce the occurrence of dust explosions in underground mining, is not applicable for surface mines. (Kirk Othmer 1993)

Black coal is then transported and fed to downstream processes. There may be variations in composition of the black coal entering the boundary of the downstream plant which will alter the emissions, e.g. sulphur and ash. In contrast, natural gas is purified upstream to achieve a defined ‘sales gas’ composition. Hence, there will be no expected variations in the composition of the natural gas fed into the downstream processes.

For this analysis, overburden was included in the category ‘Solid Waste Generation’ as the material dug out during black coal extraction loses its environmental value.

Table 4.13: Material flow data for the production of 1 t black coal form an average coal mine

Inventory data	Units	Open-cut mining	Electricity emissions	Total	Category
Input					
Black coal	t/t black coal	0	7.15E-03	7.15E-03	Product
Cooling water makeup	t/t black coal	1.03E-01	3.74E-02	1.40E-01	Freshwater Withdrawal
Boiler feedwater makeup	t/t black coal	4.56E-05	1.97E-03	2.02E-03	Freshwater Withdrawal
Output					
Black coal	t/t black coal	1.00	0	1.00	Product
Cooling water blowdown	t/t black coal	0	3.94E-03	3.94E-03	Saline Water Generation
Steam blowdown	t/t black coal	0	1.97E-03	1.97E-03	Contaminated Water Generation
CO_2	t/t black coal	5.09E-03	1.54E-02	2.05E-02	Global Warming Potential
CH_4	t/t black coal	1.42E-03	2.50E-07	1.42E-03	Global Warming Potential
N_2O	t/t black coal	1.46E-07	1.13E-07	2.59E-07	Global Warming Potential
VOC	t/t black coal	7.88E-06	1.31E-10	7.88E-06	Photochemical Oxidation Potential
CO	t/t black coal	2.85E-05	1.79E-06	3.03E-05	Photochemical Oxidation Potential
NO_x	t/t black coal	7.34E-05	3.51E-05	1.09E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t black coal	1.49E-05	9.29E-11	1.49E-05	Acidification Potential
PM_{10}	t/t black coal	3.03E-06	2.51E-06	5.54E-06	Particulate Matter Formation
Ash	t/t black coal	0	1.52E-03	1.52E-03	Solid Waste Generation
Overburden	t/t black coal	7.18	0	7.18	Solid Waste Generation

Note: Electricity is assumed to be generated from a black coal-fired PCST power station.

The original data from May (2003) can be found in Appendix A.6. Environmental data for black coal mining from Spath (1999) are included in Appendix A.10 and were found to be higher than the Australian data.

4.2.3.3. ECONOMIC FLOWS

The capital costs of coal mines are influenced by many factors:

- Black coal or brown coal
- New mine or expansion
- Open cut or underground
- Surrounding terrain
- Thermal coal or coking coal
- Domestic mine or export mine

In many reported costs, the distinctions in one or more of these parameters are not made. For this analysis, a suitable black coal project that reflects the average domestic open-cut black coal mine in Australia is required. A list of open-cut black coal mines and their costs are reported in Appendix A.11. A plot of capital costs versus capacity is shown in Figure 4.8 and the equation of the curve of best fit is shown in Equation 4.12.

$$I = 24.1Q^{1.72} \qquad \text{(Equation 4.12)}$$

where I = fixed capital investment in 2012 Australian dollars
Q = project capacity in million t/yr

Although a curve of best fit was obtained, the power exponent 1.72 is greater than 1. The exponent may not reflect the scale but other factors, including some of the features listed above.

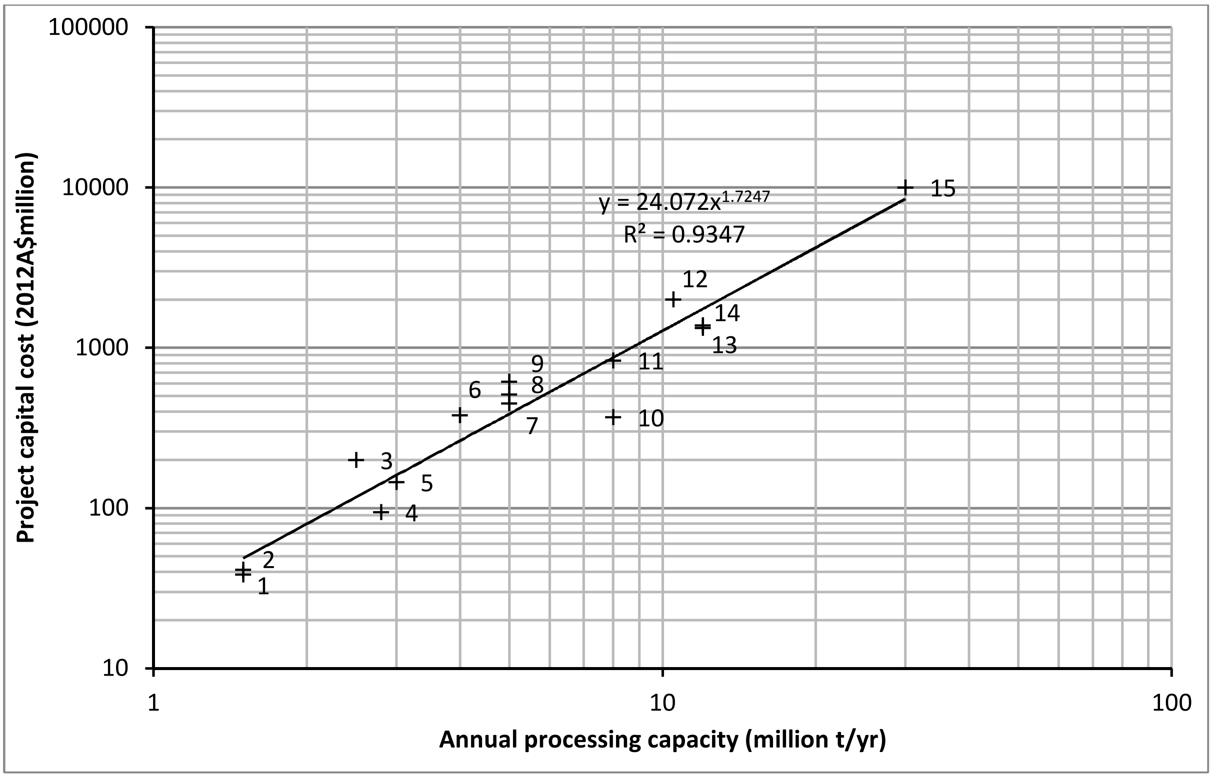


Figure 4.8: Plot of capital costs in 2012 Australian dollars against capacity in million tonnes per year for opencut black coal mines in Australia.

Note: The projects included in the diagram are (1) Rocglen (2) Boggabri (3) Duchess Paradise (4) Kogan Creek (5) Wilpinjong (6) Mt Arthur (7) Mt Penny (8) The Range (9) Elimatta (10) Mangoola/Anvil Hill (11) Rolleston (12) Mt Pleasant (13) Cobbora (14) Clement (15) Alpha.

Stanmore Coal's "The Range Thermal Coal Project" in Queensland (8) was chosen to represent to represent the upstream black coal section. It has a 5 million tonne per year capacity and produces export grade black coal. It is also an open-cut mine that uses conventional truck and shovel methods. It was selected because of its transparency in its capital and operating expenditure. The export infrastructure and costs can be identified and removed to adjust the coal mining cost to resemble closely a domestic coal mine producing coal for domestic uses (not strictly limited to power generation). The detailed procedure is located in Appendix A.12.

Both the capital and operating costs are combined, together with an allowance for royalty rates, to obtain the transfer price as shown in Table 4.14.

Table 4.14: Economic flows of a baseline black coal extraction project (Costs are expressed in 2012A$)

Product output	$5x10^6$ t/year
Capital costs (A$million)	319
Annualised capital costs (A$/tonne coal)	6.77
Cash operating costs (A$/tonne coal)	24.1
Total operating costs (A$/tonne coal)	30.8
Royalty costs (A$/tonne coal)	2.32
Final transfer price (A$/tonne coal)	33.1
Transfer price (A$/GJ-HHV)	1.36

4.2.4. COAL SEAM GAS (CSG)

4.2.4.1. INTRODUCTION

In December 2008, the CSG economic demonstrated resources (EDR) in Australia was 16,590 PJ, accounting for 12% of total gas EDR in Australia (Geoscience Australia & BREE 2014). The majority of CSG reserves are located in Queensland, which has 95 percent of the reserves with the remainder located in New South Wales. This is seen in Figure 4.9. At 2008 production rates (139 PJ/yr), this is equivalent to 119 years resource life. In the five years leading to 2008, CSG 2P reserves have been increasing by 46% per year and production has been increasing by 32% per year.

In 2012, 252 petajoules of annual production was from Queensland and 6 petajoules was from New South Wales (BREE 2013f). CSG is associated with a large number of wells required to produce the equivalent amount of natural gas produced from a conventional offshore development. By 2008, approximately 600 CSG production and exploration wells were drilled in Queensland (Geoscience Australia & BREE 2014). The drilling of CSG wells is expected to increase to meet requirements of domestic needs and new LNG projects. Three LNG projects that use CSG from Queensland are Australia Pacific LNG, Queensland Curtis LNG and Gladstone LNG. These projects will increase Australia's LNG export capacity to more than 80 million tonnes per year by 2018 (BREE 2013f). Together with other projects in the feasibility and proposal stages, Australia is set to become one of the world's largest LNG exporters by 2020 (BREE 2013f).

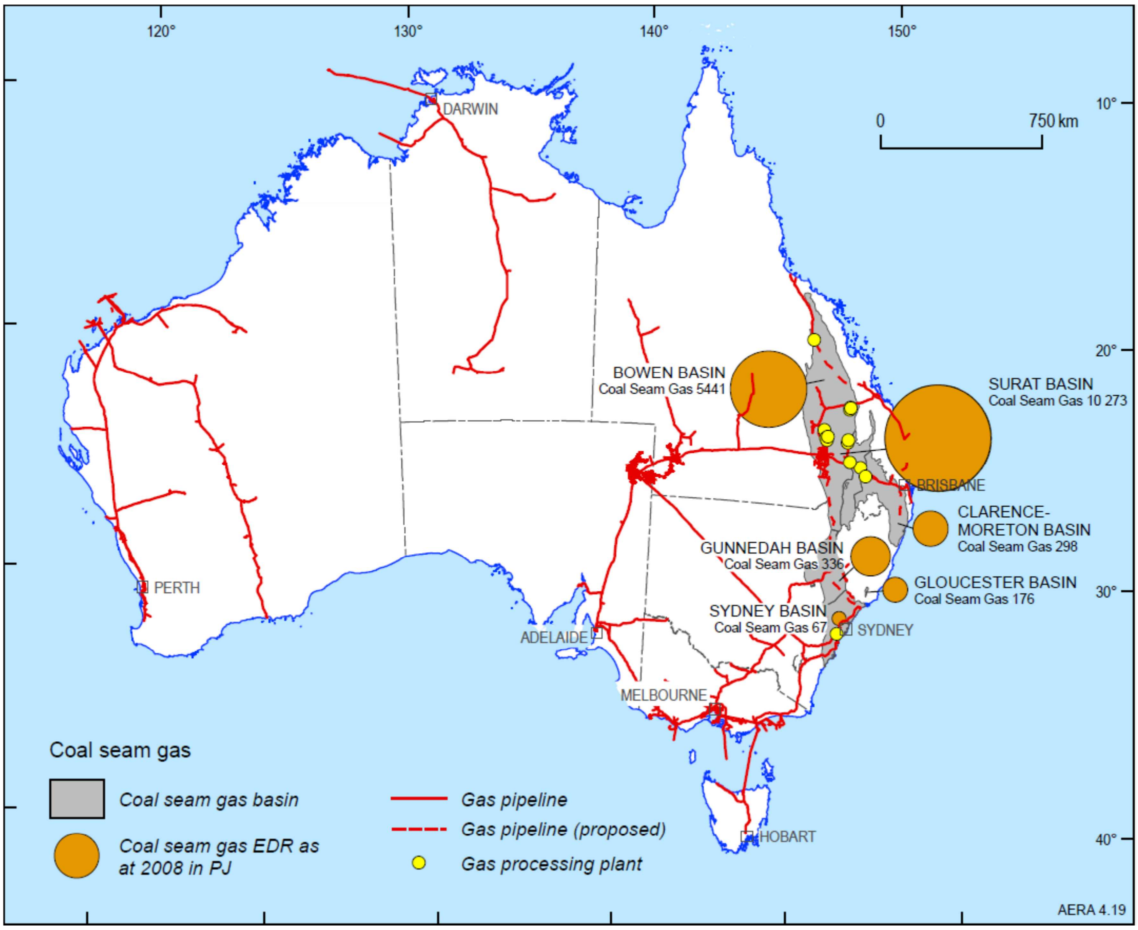


Figure 4.9: Australia's CSG reserves (Geoscience Australia & BREE 2014).

Note: The figure shows the amount of natural gas reserves for each basin.

Typical compositions of CSG at the wellhead are provided in Table 4.15. It can be seen that CSG generally has a high concentration in methane, has almost no liquids and has low concentrations of N_2 and CO_2.

Table 4.15: Average CSG composition at wellhead (QGC 2009a, APLNG 2010a, Arrow Energy 2012)

	QCLNG	APLNG	Surat gas project
N_2	2.30	2.30	1.05
CO_2	0.20	0.30	0.19
CH_4	97.50	95.70	98.75
C_2H_6	0.01	0.10	0.01
Water vapour	-	1.60	-

4.2.4.2. MATERIAL FLOWS

The material flow data for CSG extraction and purification is adapted from the Australia Pacific LNG (APLNG) Environmental Impact Statements (EIS). Data was provided for internal CSG consumption, emissions to air and associated water extraction. To adapt the data for this analysis, several assumptions were made:

- All power and heating requirements in the gas fields and gas processing plant are met by local wellhead power generation using CSG as fuel.
- All associated water extracted undergoes reverse osmosis, producing a purified water stream and a concentrated brine. The brine is left to evaporate, leaving behind a salt residue. For this study, the salt is treated as a solid waste and is disposed in a landfill.

4.2.4.2.1. Internal CSG consumption

CSG is consumed internally for power generation and in other stationary equipment. CSG is also consumed in flaring and lost through leakages and fugitive emissions. It is assumed that all local power, namely that required to run the pumps and compressors for CSG and water transportation from the gas fields, processing and treatment plants and associate infrastructure, is generated on-site using CSG from wells. The total CSG consumed in the upstream section amounted to 0.0917 tonnes CSG per tonne CSG delivered, or 8.4% of initial CSG extracted. This is derived from CO_2 emission calculations from APLNG (2010c), which is found in Appendix A.14.

4.2.4.2.2. CSG water

RPS Australia East Pty Ltd (2011) covers in detail the role of CSG water in CSG extraction. In conventional oil and natural gas reservoirs, the gas layer lies above the oil layer, which lies above the associated water layer due to its lower density. A conventional well typically draws only the top layer of oil and gas without necessarily extracting the lower water layers. The water pressure is often the force that drives the oil and gas to the earth’s surface. This is different for CSG resources, where the natural fractures in coal are filled with water and the gas is sorbed to the coal matrix. Typically, groundwater must be pumped from the confined coal seam aquifers to reduce the hydrostatic pressure and allow CSG to desorb from the coal and mobilise into the production well. This is significant in the initial stages of CSG production when the water production rate is at the highest, but this rate will decrease over time (see Figure 4.10). QGC reported that initial water extraction from a well ranged from 0.4 ML/day to 0.8 ML/day before decreasing to about 0.1 ML/day over a period of six months to a few years, while Santos reported the Fairview field in the Bowen Basin Peak to have an average initial daily water extraction of 0.2 ML/day/well before decreasing to 002 ML/day/well after 12 years

(RPS Australia East Pty Ltd 2011). Peak gas production does not occur until sufficient groundwater in the coal seam is removed.

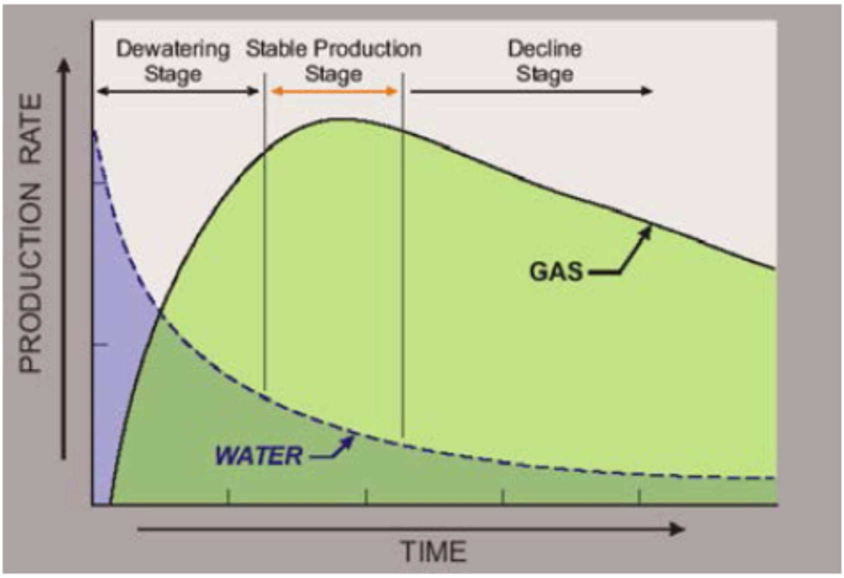


Figure 4.10: Typical CSG production gas and CSG water profile (RPS Australia East Pty Ltd 2011)

The average co-produced water per unit of energy for CSG production was reported to be 90 ML/PJ, which is approximately 5 t/t CSG produced (RPS Australia East Pty Ltd 2011). This is similar to the QCLNG project, which reported 5.1 t/t CSG produced of associated water (QGC 2009b), and the 5.43 t/t CSG produced of associated water reported for the APLNG project (APLNG 2010b).

The water produced is generally of poor quality due to elevated salinity and sodium levels and other adverse chemical properties. Table 4.16 shows an example of the CSG water composition at the wellhead.

Total dissolved solids (TDS) are a measure of solids remaining when the water is completely evaporated. As a guideline, drinking water has <0.5 g/L TDS and seawater is >30 g/L TDS (QGC 2009c). Based on the APLNG and QCLNG associated water reports, the TDS lies between 2.8 g/L and 5.5 g/L (QGC 2009c) but can go as high 7.5 g/L (APLNG 2010b). QCLNG deems its associated water to be consumable by most varieties of livestock without producing a loss in production but for irrigation purposes, the associated water is only suitable for crops that are tolerant to water salinity with a rating from high to extreme.

Sodicity or the sodium adsorption ratio (SAR) measures the proportion of sodium to magnesium and calcium in water. Water with high SAR degrades soil structures by breaking down clay aggregates, making it more susceptible to erosion and less permeable to water, consequently reducing plant growth (APLNG 2010b). The QCLNG project reported an average associated water SAR of 110, which is between 5 to 25 times the recommended limit for irrigation depending on the soil type (QGC 2009c). The SAR for the APLNG project associated water are higher and can go up to 170, which corresponds to the APLNG Spring Gully gas fields (APLNG 2010b).

Associated water may be considered a regulated waste under the Environmental Protection Regulation 2008 depending on quality (APLNG 2010b). Since associated water has an average TDS concentration of less than the salinity limit of 10 g/L, it should not be regarded as saline and therefore not considered a regulated waste (APLNG 2010b). However, as many beneficial uses of associated water require it to be at concentrations averaging 2 g/L (QGC 2009c, APLNG 2010b), a water treatment option such as desalination is required to treat the associated water. Desalination or reverse osmosis (RO) produces a permeate stream which is close to potable standards and a concentrated saline effluent stream. This brine is then contained in brine evaporation ponds to evaporate the water and salt crystals are produced.

- The APLNG project reported that up to 85% of associated water can be recovered using reverse osmosis to produce treated water with a salt content less than 0.15 g/L (APLNG 2010a). The remaining 15% exits the treatment plant in the form of a brine stream with a salt content of 60 g/L, which is twice the TDS concentration of seawater (APLNG 2010a).
- The QCLNG project reports that the 130 ML per day of associated water will produce 13 ML of brine, which in turn will produce 530 tonnes of salt per day (QGC 2009b). This implies that the produced brine stream has a concentration of more than 40 g/L.

Table 4.16: Production well average CSG water composition (QGC 2009c)

Analyte element	Production wells average (mg/L)
Aluminium	14.73
Arsenic (III)	0.014
Benzene	<0.0010
Bicarbonate alkalinity	1857.3
Boron	1.08
Cadmium	<0.01
Calcium	5.15
Carbonate alkalinity	271.78
Chloride (non-wells)	935.9
Chloride (wells)	861.1
Cobalt	0.058
Copper	2.5
Fluoride	3.3
Lead	0.07
Magnesium	4.32
Mercury	0.0008
Nickel	0.15
Nitrate	0.044
Nitrite	0.013
pH	8.6
Phenol	<0.0010
Potassium	12.19
Selenium	0.0103
Sodium (non-wells)	1975.9
Sodium (wells)	1081.5
Sulphate	6.23
Suspended solids (turbidity)	2243.3
TDS (salinity)	3558.1
TOC (total organic carbon)	1.32
Toluene	<0.003
Total iron	9.49
Zinc	1.49

Using an associated water production of 5 tonnes per tonne of CSG and APLNG data, the salt production was estimated to be 0.045 tonnes per tonne CSG. A detailed mass balance of the desalination process is located in Appendix A.13. The brine stream would be treated as a waste stream unless beneficial use for the salt can be found. In this analysis, the brine stream is assumed to have evaporated completely leaving salt as a solid waste. The treated water will be used to meet all water requirements in the CSG upstream and is considered a useful by-product.

4.2.4.2.3. Emissions to air

The APLNG project is chosen to represent the CSG upstream section in this category as the environmental impact statement includes comprehensive study on greenhouse gases and other emissions to air, as well as information on the different fuels used in the project.

The primary source of emissions to air within the gas fields as reported by the APLNG project (2009). are:

- gas-fired engines used to drive wellhead pumps and generate electricity for the gas processing and water treatment facilities
- gas compressors at the gas processing facilities
- water pumps at the water transfer stations for the transfer of water from the wellhead to the water treatment plant
- gas boilers used to regenerate the gas dehydration units
- gas flares

Table 4.17 summarises the key data that can be extracted from the APLNG project's greenhouse gas analysis, such as diesel usage, CSG consumption, and greenhouse gas emission rates. Detailed calculations are found in Appendix A.14.

Table 4.17: Material flows from the APLNG project

Diesel usage	55,727 t/yr	$4.36\text{x}10^{-3}$ t/t CSG
CSG consumption	1,171,153 t/yr	$9.17\text{x}10^{-2}$ t/t CSG
CO_2 emission rate	3,176,362 t/yr	$2.49\text{x}10^{-1}$ t/t CSG
CH_4 emission rate	2,681 t/yr	$2.10\text{x}10^{-4}$ t/t CSG
N_2O emission rate	24 t/yr	$1.85\text{x}10^{-6}$ t/t CSG

The APLNG project reported fugitive CH_4 emissions of approximately $5.22\text{x}10^{-5}$ t CH_4/t CSG produced from equipment leakages, which was equivalent to $1.10\text{x}10^{-3}$ t CO_2-e/t CSG produced. In comparison, Day et al. (2014) measured CH_4 emission rates at 43 CSG wells in Queensland and NSW and reported fugitive CH_4 emission factors for equipment leaks in the range of $1\text{x}10^{-4}$ to $2.4\text{x}10^{-3}$ t CO_2-e/t CSG produced. The emission factor for equipment leakages from APLNG falls within this range. The APLNG project also reported fugitive CH_4 emissions from high pressure pipelines which amounted to approximately $3.72\text{x}10^{-5}$ t CH_4/t CSG produced or $7.91\text{x}10^{-4}$ t CO_2-e/t CSG produced. When this figure added with the APLNG project's fugitive CH_4 emissions from equipment leakages, the total still falls within the range reported by Day et al. (2014). However, there is a possibility that the APLNG project's fugitive CH_4 emissions may be underestimated. Day et al. (2014) reported that the highest CH_4 emission rate was 44 g/min and it originated from a vent on a well pad, which means that the fugitive CH_4 emissions could potentially reach $3.14\text{x}10^{-3}$ t CH_4/t CSG produced or 0.066 t CO_2-e/t CSG produced for some wells.

Day et al. (2014) reported a mean CH_4 emission rate of approximately 3.2 g/min or 7m^3/day. The principal sources of the CH_4 emissions were venting, operation of gas-powered pneumatic devices, equipment leaks and exhaust from gas-fuelled water pump engines. For a mean CH_4 emission rate of approximately 3.2 g/min or 7 m^3/day. Compared to a mean production rate of 29,600 m^3/day for the 43 wells, the reported CH_4 emission rate represented 0.02% of total CSG production. In comparison, the lowest recorded fugitive CH_4 emission values from the U.S. unconventional gas industry were around 0.42% to 0.47% of gross natural gas production (Allen et al. 2013, EPA 2013). Both the Australian and U.S. data were measured bottom-up and represented fugitive CH_4 emissions from the gas production facilities in the gas field only. The U.S. fugitive CH_4 emissions were found to be higher because U.S. unconventional gas production includes shale and tight gas which involve different production methods and produce different rates of emissions as compared to Australian CSG production. The CH_4 emission figure from the APLNG project in Table 4.17 represented 0.44% of CSG production and is at a similar level to the U.S. fugitive CH_4 emissions. This is higher than the 0.02% reported by Day et al. (2014) because it includes fugitive CH_4 emissions, CH_4 emissions from flaring and CSG combustion in the upstream extraction and purification section.

One type of fugitive emission that the APLNG project did not record was that from venting. Day et al. (2014) estimated the fugitive CH_4 emissions from venting to be 9.1x10^3 t CO_2-e/t CSG, which was much higher than the fugitive CH_4 emissions from equipment leakages. When venting emissions are considered, the fugitive emissions from the APLNG project is expected to increase significantly. Hence, the actual CH_4 emissions from the upstream extraction and purification section may be larger than that reported in this study.

The Talinga gas processing plant owned by Origin is a part of the APLNG project development and is a key component in estimating the emissions to air from CSG production. The 90 TJ/day gas processing plant is part of a development that comprises of a 20 ML/day reverse osmosis water treatment facility and 111 operating CSG wells (APLNG 2009). Using this information, the emissions to air can be calculated as shown in Appendix A.15. The results of the calculations are shown in Table 4.18.

Table 4.18: Other emissions to air from the APLNG project

Pollutants	NO_x (t/t CSG)	CO (t/t CSG)	SO_2 (t/t CSG)	PM_{10} (t/t CSG)	VOC (t/t CSG)
Gas processing facilities	4.38x10^{-4}	1.35x10^{-3}	3.12x10^{-7}	1.54x10^{-7}	-
Water facilities	4.11x10^{-4}	2.63x10^{-5}	4.78x10^{-9}	5.67x10^{-8}	-
Wellhead water pump gas-fired generators	9.55x10^{-6}	7.16x10^{-6}	6.69x10^{-10}	-	-
Gas flares	2.08x10^{-6}	1.13x10^{-5}	6.24x10^{-5}	-	4.28x10^{-6}
Total	8.61x10^{-4}	1.40x10^{-3}	6.27x10^{-5}	2.11x10^{-7}	4.28x10^{-6}

4.2.4.2.4. Emissions to air

The material flows of the CSG upstream section are summarised in Table 4.19.

Table 4.19: Material flow data for CSG upstream system

Inventory data	**Units**	**Values**	**Category**
Input			
Coal seam gas	t/t CSG	9.17E-02	Fuel
Produced water	t/t CSG	5.00	Associated Water Withdrawal
Output			
Coal seam gas	t/t CSG	1.00	Product
CO_2	t/t CSG	2.49E-01	Global Warming Potential
CH_4	t/t CSG	2.10E-04	Global Warming Potential
N_2O	t/t CSG	1.85E-06	Global Warming Potential
VOC	t/t CSG	4.28E-06	Photochemical Oxidation Potential
CO	t/t CSG	1.40E-03	Photochemical Oxidation Potential
NO_x	t/t CSG	8.61E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t CSG	6.27E-05	Acidification Potential
PM_{10}	t/t CSG	2.11E-07	Particulate Matter Formation
Salt	t/t CSG	4.50E-02	Solid Waste Generation

Note: Salt is assumed to be a solid waste as it could not be used for any practical purpose due to its high impurity level

4.2.4.3. CAPITAL COSTS

A capital cost model is created using the capital costs of six existing CSG projects in Australia. This cost model is used to estimate the capital costs of a CSG upstream project with a given production capacity. It follows Equation 4.13 and is shown in Figure 4.11. Details for these six CSG projects are located in Appendix A.16.

$$I = 20.7Q^{0.87} \qquad \text{(Equation 4.13)}$$

where I = fixed capital investment in 2012 Australian dollars
Q = project capacity in petajoules per year (PJ/yr).

An alternative method to estimate the upstream costs of CSG production is to use capital cost assumptions derived from Core Energy (2012) as shown in Table 4.20. Many of these assumptions, including that of the water treatment facilities, are based on the CSG production rate. These costs were reported in 2012 Australian dollars.

Table 4.20: Capital cost assumptions for CSG upstream section (Costs are expressed in 2012A$) (Core Energy Group 2012)

Upstream section component	Facilities	Cost (A$2012)	Units
CSG extraction	Drilling cost	1.75	A$million/well
	Rig mobilisation cost	0.200	A$million/well
	Completion cost	0.810	A$million/well
	Wellhead/flowlines	0.716	A$million per well
CSG processing plant	Gas processing capacity	4.32	A$million per PJ/yr
	Compression	0.219	A$million per PJ/yr
Water treatment plant	Water treatment	3.23	A$million per PJ/yr
	Ponds cost	0.590	A$million per PJ/yr

These assumptions are used to estimate the capital costs of two existing CSG projects, the Spring Gully project and the Talinga project. These two projects were selected because they provided information regarding the gas processing capacity and the number of wells. The estimated capital costs are reported in Table 4.21. The official capital costs of the Spring Gully project are also included in Table 4.21 for comparison. It was found that the difference is approximately $100 million.

Table 4.21: Comparison of CSG upstream costs (Costs are expressed in 2012A$)

CSG project	Included components	Original costs	Costs adjusted to 2012A$	Costs using Core Energy assumptions at A$2012 (Table 4.20) [a]
Spring Gully	36 TJ/day gas processing capacity with 48 wells (Origin Energy 2005)	A$200 million (2005) [a]	A$365 million	A$277million
	85 TJ/day gas processing capacity with 94 wells (Origin Energy 2008)	A$200 million (2005) + A$115 million (2007) (Origin Energy 2005)	A$498 million	A$586 million
Talinga	90 TJ/day gas processing capacity with 111 wells (Origin n.d.)	-		A$660 million

[a] Includes costs for gas processing, wellhead, flowlines, compression, water treatment and ponds costs.

When the three capital cost estimates using the Core Energy assumptions are plotted on a capital cost versus capacity graph, they form Equation 4.14.

$$I = 26.0Q^{0.92} \qquad \text{(Equation 4.14)}$$

When compared with Equation 4.13, Equation 4.14 produces a higher capital cost for CSG upstream processes. This can be seen in Figure 4.11.

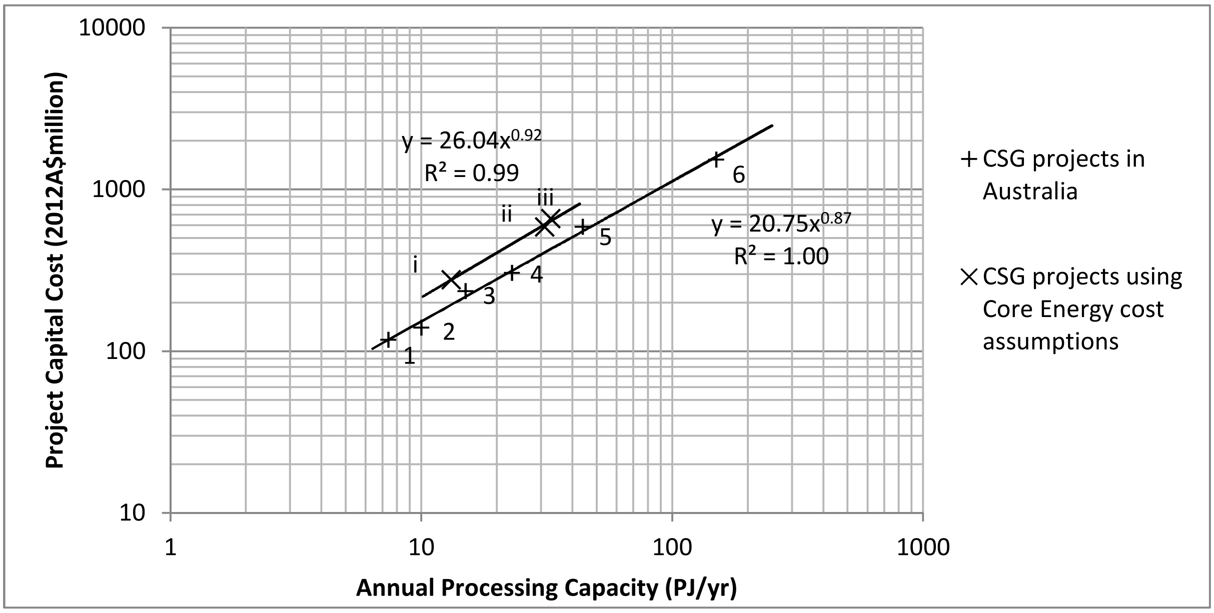


Figure 4.11: Capital costs of CSG projects in 2012 Australian dollars against annual processing capacity on PJ/yr. Note: The projects included in the diagram are (1) Argyle (2) Tipton West (3) Gloucester (4) Talinga (5) Darling Downs (6) Narrabri

In addition, the costs of the water treatment plants may not necessarily be based on the gas processing capacity, but on the water treatment capacity itself. When utilised to estimate the capital costs of water treatment facilities, the Core Energy assumptions showed these estimates to be higher than actual reported costs as seen in Table 4.22. This indicates that the Core Energy assumptions may potentially overestimate the capital costs of a CSG project.

Table 4.22: Comparison of CSG water treatment facility costs (Costs are expressed in 2012A$)

	Included components	Original costs	Costs adjusted to A$2012	Costs using Core Energy assumption (Table 4.20)
Spring Gully (36 TJ/day)	9 ML/day water treatment plant (Robertson 2008)	$20 million (2008) (Robertson 2008)	$22 million	$50.2 million
Talinga (90 TJ/day)	20 ML/day water treatment plant (Origin n.d.)	$70 million (2009) (Gas Today 2009)	$77 million	$125 million

For this analysis, Equation 4.13 was chosen to best represent the capital costs of the CSG upstream section as it was representative of existing CSG projects in Australia.

Individual capital costs were required for CSG extraction, gas processing plant and water treatment plant in order to calculate their respective operating costs. The approach was to use Equation 4.13 to estimate the total capital cost of the CSG upstream section, then use the Core Energy assumptions to calculate the capital costs of the CSG processing plant and water treatment plant. These two capital costs are then subtracted from the total capital cost to obtain the capital cost of the CSG extraction stage.

The Talinga project was chosen to represent the CSG upstream section. It comprises a 90 TJ/day gas processing plant, 20 ML/day water treatment plant and 111 CSG wells. The total upstream capital costs were calculated using Equation 4.13 to be $428 million in 2012 Australian dollars. The capital costs of the CSG extraction, CSG processing plant and water treatment plant respectively are $137 million, $165 million and $125 million respectively in 2012 Australian dollars.

4.2.4.4. OPERATING COSTS

The operating costs of the CSG upstream section can be divided into the operating costs of the extraction stage and the purification stage. The operating costs for the extraction stage, which includes wellheads, flowlines and non-plant related running costs, is estimated using lease operating costs for U.S. coalbed methane production provided by the U.S. Energy Information Administration (2010). This was estimated to be approximately $0.95/t CSG extracted. Detailed calculations are located in Appendix A.17.

The purification costs are estimated based on the Talinga project's 90 TJ/day gas processing facility and 20 ML/day water treatment facility. As the assumption was that all power was generated on-site using gas-fired engines, imported electricity is not required and is excluded from the operating costs.

Gas processing facilities and water treatment plants generally operate continuously, with one or two operators present during daylight hours and on-call after hours (APLNG 2010a). It was assumed that the 90 TJ/day gas processing plant and the 20 ML/day water treatment plant will each have 2 full-time operators. In the event one operator will have to visit the wells and other facilities outside the boundaries of the plants, there will be one operator remaining to look after the plant.

The operating cost sheet model for the gas processing plant and the water treatment plant can be found in Table 4.23 and Table 4.24 respectively.

Table 4.23: Operating cost sheet for CSG gas processing plant (Costs are expressed in 2012A$)

Plant capacity	90	TJ/day			
Plant availability	85%				
Annual actual production	544,000	t/yr			
Fixed capital investment	165	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per tonne CSG ($/t CSG)**
Raw materials		Unit usage (/t CSG)	Unit cost ($/unit)		
Coal seam gas fuel	t			-	-
Utilities		Unit usage (/t CSG)	Unit cost ($/unit)		
Cooling water	t	-	0.08	-	-
Demineralised water	t	-	1.50	-	-
Total variable cost				**-**	**-**
Operating labour		No.	Salary ($/yr)		
Operators/shift		2			
Shift teams		5			
Total shift operators		10	107,000	1.07	1.97
Total operating labour costs				**1.07**	**1.97**
Payroll overheads		40	% total operating labour costs	**0.43**	0.79
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.22	0.41
Maintenance labour		1		1.65	3.04
Maintenance materials		1		1.65	3.04
Consumable stores			10	0.15	0.28
Plant overheads			100	1.50	2.75
Laboratory			10	0.15	0.28
Insurance		1		1.65	3.04
Property taxes		1		1.65	3.04
Total fixed costs				**10.14**	**18.64**
Total manufacturing costs				**10.14**	**18.64**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	0.46	0.84
Marketing costs		5	Total production cost	0.57	1.05
Research and development costs		2	Total production cost	0.23	0.42
General expenses				**1.25**	**2.30**
Total product cost				**11.39**	**20.94**

Table 4.24: Operating cost sheet for CSG water treatment facility (Costs are expressed in 2012A$)

Plant capacity	20 ML/day					
Plant availability	85%					
Annual actual production	6,210,000 t/yr					
Fixed capital investment	125 $ million					
Capital exponent,ψ (I=αQψ)	0.7					
Cost year	2012 AUD$					
Operating costs				**Annual cost ($ million)**	**Cost per tonne water ($/t water)**	**Cost per tonne CSG ($/t CSG)**
Raw materials		Unit usage (/t water)	Unit cost ($/unit)			
Utilities		Unit usage (/t water)	Unit cost ($/unit)			
Electricity	MWh	-	70.00	-	-	-
Total variable cost				-	-	-
Operating labour		No.	Salary ($/yr)			
Operators/shift		2				
Shift teams		5				
Total shift operators		10	107,000	1.07	0.17	1.97
Total operating labour costs				**1.07**	**0.17**	**1.97**
Payroll overheads		40	% total operating labour cost	**0.43**	0.07	0.79
		% fixed capital	**% operating labour + payroll overheads**			
Supervision			15	0.22	0.04	0.41
Maintenance labour		1		1.25	0.20	2.31
Maintenance materials		1		1.25	0.20	2.31
Consumable stores			10	0.15	0.02	0.28
Plant overheads			100	1.50	0.24	2.75
Laboratory			10	0.15	0.02	0.28
Insurance		1		1.25	0.20	2.31
Property taxes		1		1.25	0.20	2.31
Total fixed costs				**8.54**	**1.38**	**15.70**
Total manufacturing costs				**8.54**	**1.38**	**15.70**
Non-manufacturing costs		(%)	Factor			
Administrative costs		4	Total production cost	0.38	0.06	0.71
Marketing costs		5	Total production cost	0.48	0.08	0.88
Research and development costs		2	Total production cost	0.19	0.03	0.35
General expenses				**1.06**	**0.17**	**1.94**
Total product cost				**9.60**	**1.55**	**17.64**

4.2.4.5. TRANSFER PRICE

The capital and operating costs for both the extraction and purification stages are combined together with an estimate of the royalty rate to form the transfer price of CSG as shown in Table 4.25.

Table 4.25: Economic flows of a baseline CSG extraction and purification project (Costs are expressed in 2012A$).

Product output	6.34×10^5 t/year		
Upstream section	Extraction	Gas processing	Water treatment
Capital costs (A$million)	137	165	125
Annualised capital costs (A$/t)	26.7	32.3	24.8
Cash operating costs (A$/t)	0.98	20.9	17.6
Total operating costs (A$/t)	123		
Royalty costs (A$/t) [a]	15.2		
Transfer price (A$/t)	138		
Transfer price (A$/GJ-HHV)	2.69		

[a] Assumed to be 11% of transfer price.

4.2.5. DIESEL

4.2.5.1. INTRODUCTION

Diesel is included in the study as an alternative substitute fuel where black coal is not appropriate, such as in peaking grid electricity generation and in the mining sector. The diesel is assumed to be low in sulphur (<0.05% S). It is one of the many products derived from crude oil in petroleum refineries. Diesel production involves extraction of crude oil from wells (mostly offshore in Australia) and purification in a petroleum refinery to obtain the final diesel product.

4.2.5.2. MATERIAL FLOWS

May (2003) reported the LCI for the production of 1 t mixed petroleum products and used this LCI to derive the LCI for natural gas extraction using an allocation procedure (see Chapter 4.2.2.3). This LCI was not chosen to represent the LCI for diesel production as it does not include the LCI for the refinery component. Instead, the LCI for diesel production was adapted from Sheehan et al. (1998) which reported LCI for both crude oil extraction and diesel production from the refinery. Detailed calculations to adjust the LCI and convert the natural gas and electricity into indirect emissions are located in Appendix A.18. The LCI were found to be lower than the LCI reported by May (2003) in Appendix A.6 in units of t/t mixed petroleum products produced.

Sheehan et al. (1998) estimated the percentage by mass of low-sulphur diesel fuel in total refinery production by first adding together the total output of the various petroleum products from all U.S. refineries and then calculating the proportion of low-sulphur diesel fuel from this total, which was 13.4% of total U.S. refinery production as shown in Figure 4.12. Based on this percentage, 13.4% of total emissions, raw materials and energy use required by the refinery were allocated to the production of low-sulphur diesel. The approach does not consider the contribution of inputs and releases that are uniquely associated with diesel versus the other refinery products. The 13.4% figure is a U.S. average that was not based on any specific refinery and will not be valid for every type of refinery.

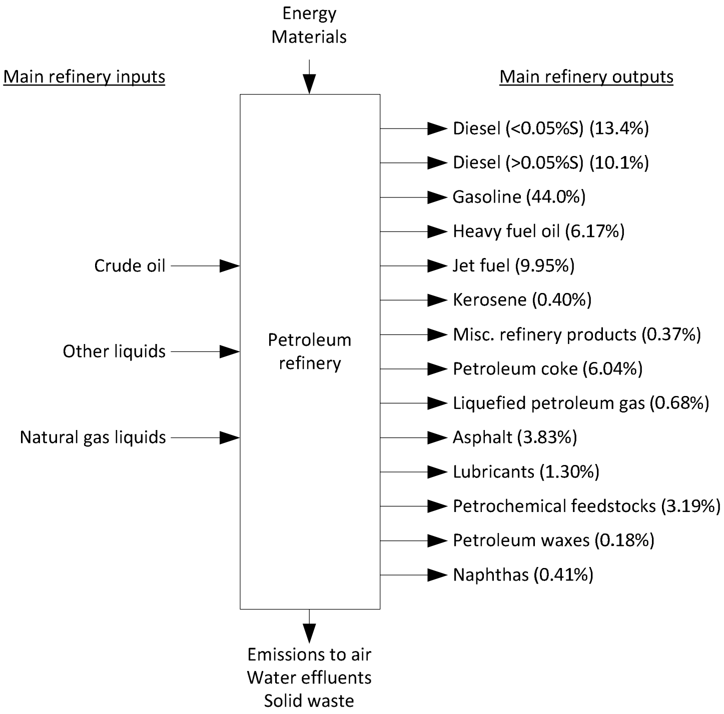


Figure 4.12: Diagram of a typical U.S. petroleum refinery showing the inputs and outputs. The mass of the products are in relation to total refinery production in %.

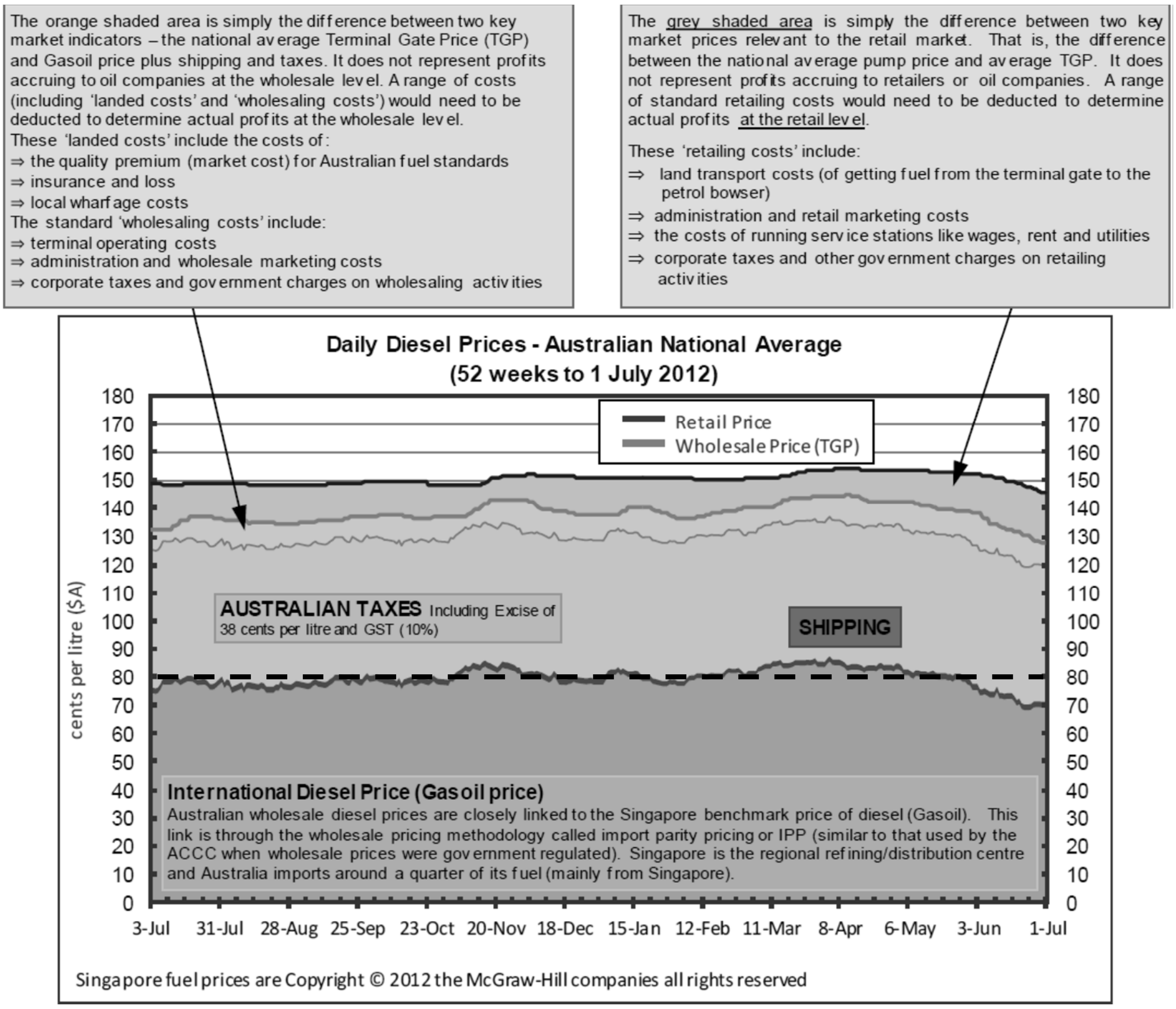
The LCI data from Sheehan et al. (1998) included natural gas and electricity consumption in diesel manufacturing, which are substituted with environmental data for heating and electricity generation from diesel. Table 4.26 summarises the LCI data for crude oil extraction after allocation of impacts and diesel production from crude oil. It can be seen that the majority of environmental impacts occur at the refinery level.

Table 4.26: Material flows for the production of 1 t low-sulphur diesel

Inventory data	Units	Crude oil extraction (offshore platform)	Crude oil processing (refinery)	Substitute natural gas and electricity with diesel	Total	Category
Input						
Crude oil	t/t diesel	3.07E-02	1.07E+00	0	1.10E+00	Feedstock
Diesel	t/t diesel	0	0	4.32E-02	4.32E-02	Fuel
Water (unspecified)	t/t diesel	0	4.35E-02	0	4.35E-02	Freshwater Withdrawal
Output						
Diesel	t/t diesel	0	1.00E+00	0	1.00E+00	Product
Coal	t/t diesel	0	2.05E-04	0	2.05E-04	Fuel
CO_2	t/t diesel	9.58E-03	2.61E-01	1.63E-01	4.34E-01	Global Warming Potential
CH_4	t/t diesel	1.98E-05	9.74E-05	3.20E-06	1.20E-04	Global Warming Potential
N_2O	t/t diesel	2.34E-07	6.42E-06	1.44E-06	8.09E-06	Global Warming Potential
VOC	t/t diesel	1.93E-05	1.11E-03	2.44E-05	1.15E-03	Photochemical Oxidation Potential
CO	t/t diesel	9.41E-06	2.28E-04	2.29E-04	4.66E-04	Photochemical Oxidation Potential
NO_x	t/t diesel	1.04E-05	5.48E-04	5.85E-04	1.14E-03	Acidification Potential, Photochemical Oxidaton Potential
SO_2	t/t diesel	9.91E-07	1.87E-03	1.48E-06	1.87E-03	Acidification Potential
PM_{10}	t/t diesel	1.81E-07	2.73E-04	3.13E-05	3.04E-04	Particulate Matter Formation
Solid waste	t/t diesel	1.04E-05	6.55E-03	0	6.56E-03	Solid Waste Generation

4.2.5.3. ECONOMIC FLOWS

The study does not calculate the capital cost or operating cost of diesel production as it did for natural gas, black coal and CSG. Instead, the study estimates a transfer price for diesel using the international diesel price. The Australian Institute of Petroleum (AIP) publishes a weekly report on diesel prices in Australia. Figure 4.13 is a snapshot of diesel prices from 3 July 2011 to 1 July 2012. The international diesel price averages around \$0.80/L in 2012 Australian dollars during this period. It is assumed that this is the price at which diesel is sold in bulk to industrial customers such as mining and plants on long term contracts. The retailing costs, landed costs, wholesaling costs, Australian taxes and shipping costs are excluded from the diesel price. This price is equivalent to \$20.2/GJ-HHV or \$888/t diesel, assuming a low-sulphur diesel or fuel oil HHV of 39.7 MJ/L and a specific volume of 1110 L/t (Penney et al. 2012).



The orange shaded area is simply the difference between two key market indicators – the national average Terminal Gate Price (TGP) and Gasoil price plus shipping and taxes. It does not represent profits accruing to oil companies at the wholesale level. A range of costs (including 'landed costs' and 'wholesaling costs') would need to be deducted to determine actual profits at the wholesale level.
These 'landed costs' include the costs of:
⇒ the quality premium (market cost) for Australian fuel standards
⇒ insurance and loss
⇒ local wharfage costs
The standard 'wholesaling costs' include:
⇒ terminal operating costs
⇒ administration and wholesale marketing costs
⇒ corporate taxes and government charges on wholesaling activities

The grey shaded area is simply the difference between two key market prices relevant to the retail market. That is, the difference between the national average pump price and average TGP. It does not represent profits accruing to retailers or oil companies. A range of standard retailing costs would need to be deducted to determine actual profits at the retail level.

These 'retailing costs' include:
⇒ land transport costs (of getting fuel from the terminal gate to the petrol bowser)
⇒ administration and retail marketing costs
⇒ the costs of running service stations like wages, rent and utilities
⇒ corporate taxes and other government charges on retailing activities

International Diesel Price (Gasoil price)
Australian wholesale diesel prices are closely linked to the Singapore benchmark price of diesel (Gasoil). This link is through the wholesale pricing methodology called import parity pricing or IPP (similar to that used by the ACCC when wholesale prices were government regulated). Singapore is the regional refining/distribution centre and Australia imports around a quarter of its fuel (mainly from Singapore).

Singapore fuel prices are Copyright © 2012 the McGraw-Hill companies all rights reserved

Figure 4.13: Excerpt of diesel prices from 3 July 2011 to 1 July 2012 (AIP 2014)

4.2.6. SUBSTITUTION IMPACTS FOR UPSTREAM SECTION

A natural gas scarcity will create a need for substitute fuels to replace lost natural gas supplies. The scarcity will affect all downstream natural gas users as shown in Figure 4.2, each of which requires a certain amount of natural gas. The total natural gas lost is a combination of the natural gas requirements for each downstream user and was estimated to be 16.3 million t/yr. For the black coal and diesel substitute scenario, 9.39 million tonnes per year of natural gas is replaced with black coal and 6.87 million tonnes per year is replaced with diesel. For the CSG scenario, all 16.2 million tonnes per year of natural gas is substituted with CSG.

Table 4.27 summarises the environmental and economic impacts of the substitution from natural gas to either black coal and diesel or CSG. The normalised environmental impact indicators show the increase or decrease in environmental impacts for every t natural gas substituted. For example, substitution of natural gas with black coal will cause a significant increase in solid waste generation due to the overburden produced in coal mining. Another example is that substitution of natural gas with CSG will cause a significant increase in associated water withdrawal due to the high volumes of coal seam water produced during CSG extraction. It can be observed that substitution of natural gas with black coal and CSG will result in a decrease in most environmental impact categories, while substitution with diesel will result in an increase in most impact categories.

The economic impact indicators show the change in total operating cost for every t natural gas replaced with alternative fuels. Although substitution of natural gas with CSG will result in a greater saving in cash operating costs as compared to substitution with black coal, the high increase in annualised capital cost turns this into an operating cost penalty. The increase in annualised capital cost for substitution with black coal also negates most of the cash operating cost saving.

The actual calculations to obtain the substitution impact indicators for the upstream section can be found in Appendix A.19.

Table 4.27: Substitution impact indicators for upstream sections of different natural gas alternatives in Australia

Feedstock	NG→BlC	NG→D	NG→CSG
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	- 1.98E-10	+ 1.43E-10	- 1.14E-10
Acidification Potential (ADP)	- 3.51E-10	+ 4.39E-10	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 2.40E-09	+ 3.77E-10	- 3.93E-09
Particulate Matter Formation (PMF)	- 4.40E-11	+ 1.38E-10	- 9.29E-11
Freshwater Withdrawal (FWW)	+ 5.30E-13	- 1.23E-12	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 4.31E-10	+ 1.44E-08
Saline Water Generation (CWG)	- 3.22E-13	+ 5.02E-15	- 7.17E-13
Solid Waste Generation (SWG)	+ 1.71E-07	+ 3.76E-11	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+ 17.3	n/a	+ 83.4
Cash operating costs	- 11.8	n/a	- 33.7
Total operating costs	+ 5.5	n/a	+ 49.7

Legend: ‘+’ sign denotes increase in impacts, ‘-‘ sign denotes decrease in impacts, NG=Natural Gas, BlC=Black Coal, CSG=Coal Seam Gas, D=Diesel

4.3. GRID ELECTRICITY GENERATION

4.3.1. INTRODUCTION

The grid electricity industry is one of Australia's largest industries and is dominated by generation from fossil fuels (see Figure 4.14). According to BREE (2013b), black coal had the highest share in the 2012 electricity generation mix with a production of 120,000 GWh. This is followed by brown coal with a generation share of 55,100 GWh, natural gas with 48,900 GWh, renewables with 24,000 GWh and the remainder consisting of oil and multi-fuels with 3,070 GWh and 2,500 GWh respectively. BREE (2013a) reported that a total of 1,170 PJ of black coal, 767 PJ of brown coal, 439 PJ of natural gas and 21 PJ of automotive diesel oil were used in Australia's 2012 grid electricity generation.

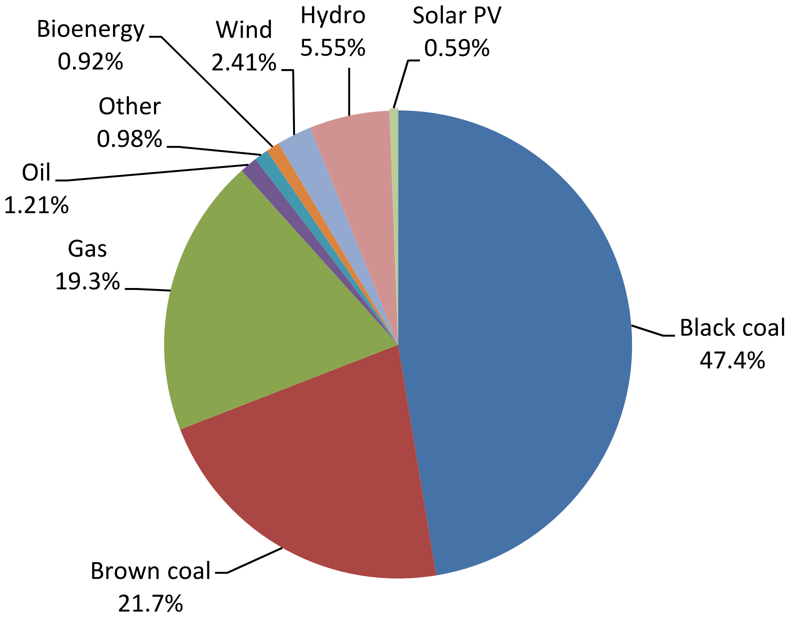


Figure 4.14: Grid electricity generation breakdown by fuel (%) in Australia, 2012.
Note: 'Other' includes multi-fuel power plants (BREE 2013e).

Australia's grid electricity can be divided into baseload electricity and peaking electricity. This analysis will examine the suitable fuels and technology that are used to generate both types of grid electricity. Grid electricity is assumed not to include off-grid or non-grid electricity which is generated outside the grid. This will be covered under Mining in Chapter 4.4.

Although the current Australian electricity mix is dominated by coal, the share of other sources such as gas are expected to increase in the future. An example of future projection of Australia's grid electricity mix is from Syed (2012a), who projects that black coal-fired generation will continue to be part of the electricity mix to 2050, but will gradually decline due to a shift from coal to other sources such as gas-fired generation. Syed (2012a) stated that these results implied the partial or full closure of coal-fired capacity. Stock (2014) also observed that many of Australia's coal-fired power stations use outdated sub-critical technology as opposed to the more efficient technologies such as super or ultra-super-critical technology. The age of Australia's coal-fired power stations limit their potential to be retrofitted with Carbon Capture and Storage (CCS) technology which can lower their greenhouse gas emission intensity.

A current electricity fuel mix is required to represent grid electricity generation for the whole of Australia prior to substitution of natural gas. For this purpose, the NSW electricity fuel mix (e.g. 70% black coal, 12% natural gas and 18% renewables) is chosen because it closely resembles the fuel breakdown in Figure 4.14 . The environmental and economic impacts of grid electricity generation using this fuel mix are a combination of the data in the later chapters and the calculations are given in Appendix A.20.

4.3.2. JUSTIFICATION OF FUELS AND TECHNOLOGIES

Under the scenario of a natural gas scarcity, replacement or closure of coal-fired power stations will be less likely. Instead, gas-fired power stations will lose their energy source and alternative energy sources are required to make up for the gas-fired electricity generation loss in peaking and baseload grid electricity generation applications. The different types of grid electricity will impose different constraints on the alternative fuels that can be used.

Black coal power stations are still a feasible option due to the abundance of black coal and the maturity of efficient steam turbine (ST) technology. However, black coal power stations have significantly high capital costs and may face competition from renewables which may experience cost reductions in the future derived from technology improvement. The advancement of coal-fired electricity generation will also be heavily dependent on technological and other developments related to CCS. For the time being, large baseload combined cycle gas turbine (CCGT) power stations can be substituted with coal-fired power stations, as coal-based power generation technologies are mature proven technologies that are economically competitive at large scales.

Peaking power plants generally run only when there is a peak demand in grid electricity, e.g. during hot summer afternoons when air conditioning is widely used. These plants need to be brought on quickly to meet the rapidly increasing demand for power during these peak occasions, and taken offline quickly as power demand diminishes, e.g. in the evening. During a natural gas scarcity, an alternative energy source is required to respond as quickly to meet peaking demand as open cycle gas turbine (OCGT) systems. Black coal systems are considered unsuitable for this application because of their long start-up times. Additionally, black coal power stations have relatively high capital costs and can only compete with other technologies such as gas by relying on economies of scale, so they are infeasible to match small scale power demands. Diesel engines and CSG fuels are considered to be most suitable as an alternative to natural gas in OCGT applications. Normally, diesel engines are used in places without connection to a power grid, or as an emergency power supply if the grid fails.

4.3.3. NATURAL GAS/CSG

According to BREE (2013e), more than half of Australia's 2012 gas-based grid electricity generation capacity consisted of OCGT technology, which was used to meet peaking power demand. 6,873 MW of OCGT capacity was fuelled by conventional gas and 519 MW was by CSG. Combined cycle gas turbine (CCGT) technology has the second largest share and is used to generate constant baseload grid electricity. 2,612 MW of CCGT capacity was generated using conventional gas and 1,395 MW was generated using CSG. Gas-fuelled steam turbine (ST) technology has a significant share of gas-based electricity generation capacity, which is 2,190 MW.

Although OCGT systems make up a larger share of Australia's generation capacity, the capacities are not fully utilised as they are operated infrequently, hence they do not consume as much natural gas as CCGT systems. The capacity utilisations for ST, OCGT and CCGT were assumed to be 25%, 10% and 85% respectively. The efficiencies of ST and OCGT were assumed to be 35.2%, while CCGT was assumed to have a higher efficiency of 51.6%. A detailed calculation revealed that only 21.0% of natural gas consumption in the grid electricity sector is attributed to OCGT systems while 63.4% is attributed to CCGT systems and the remainder to ST systems (see Figure 4.15). These calculations are located in Appendix A.21.

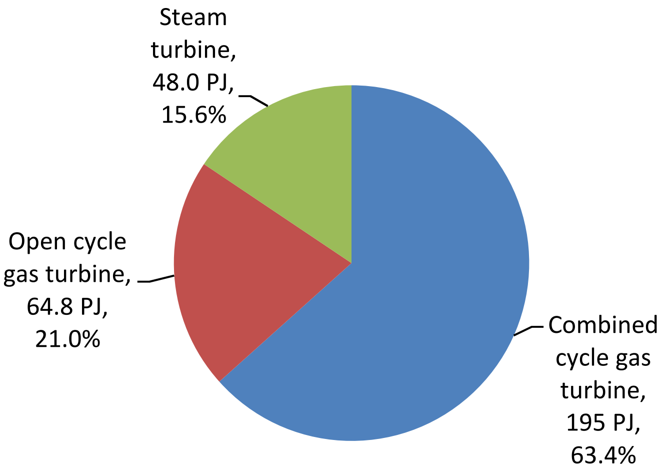


Figure 4.15: Breakdown of natural gas usage for the electricity generation sector in Australia, 2011, by energy units and percentages (BREE 2013e).

4.3.3.1. TECHNOLOGY DESCRIPTION

ST technologies produce steam in boilers by burning natural gas in boilers to produce steam, which is used to run steam turbines and generate electricity. The ST technologies are also similarly applied to other fuels such as black coal, brown coal and in some cases multi-fuel power stations.

OCGT technologies produce electricity by combustion in gas turbines. They eliminate the need for steam generation as required for ST technology, thus they have lower water consumption. Their simpler design enables them to start generating electricity quicker than other technologies, making them preferable for meeting sudden increases in electricity demand. They can also be used to meet electricity demands of small scale projects. These technologies have lower capital costs but lower efficiencies, thus resulting in higher natural gas consumption and CO_2 emissions for every t natural gas consumed. A typical OCGT configuration is shown in Figure 4.16.

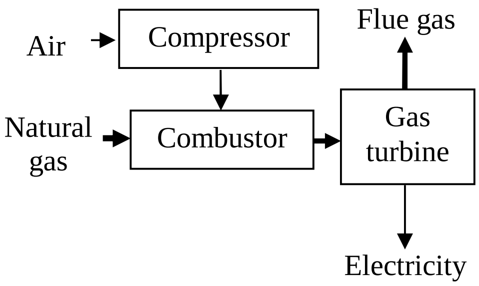


Figure 4.16: Process flow diagram for OCGT power plant showing major inputs and outputs

CCGT power station technologies have the highest efficiencies out of the three gas-based technologies. This is achieved by combining an OCGT with a steam turbine, where hot flue gases from the gas turbine provide heat to generate steam for the steam turbine. This arrangement utilises less fuel and lower CO_2 emissions for the same generation output as compared to the other gas technologies. A typical CCGT arrangement is shown in Figure 4.17.

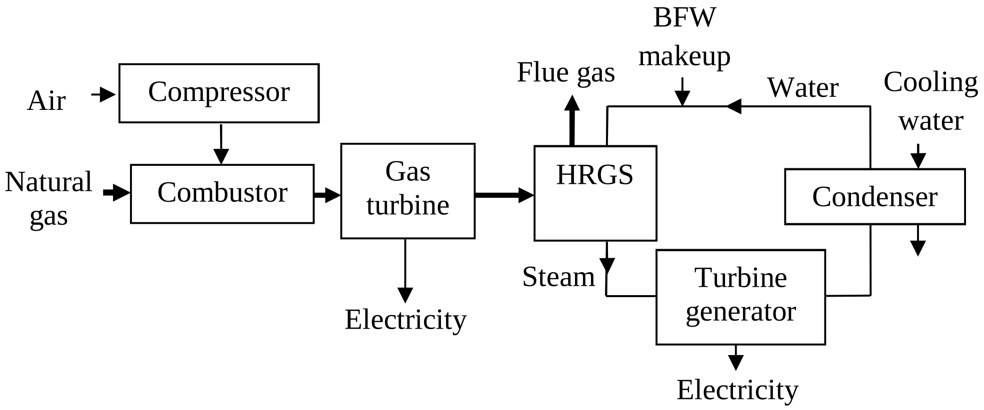


Figure 4.17: Process flow diagram for CCGT power plant showing major inputs and outputs

By capturing waste heat and extracting steam from various points in the cycle, gas turbine technologies can also be converted for cogeneration purposes where steam can be used in partner facilities, leading to overall improvements in efficiencies and emissions.

For this analysis, the OCGT and CCGT technologies will be studied in detail. The ST technology will be covered briefly in Chapter 5.1, where data from OCGT is extrapolated to estimate data for ST.

4.3.3.2. MATERIAL FLOWS

4.3.3.2.1. Open cycle gas turbine (OCGT) technology

For this study, the LCI for OCGT systems is calculated manually using fuel data and emission factors. May (2003) has published LCI for OCGT systems in Australia, but were limited to systems with an average efficiency of 25.7%. However, the literature provided fuel data which can be used to estimate the emissions to air from an OCGT system. This LCI data for OCGT systems are found in Appendix A.22.

The average efficiency of 25.7% reported by May (2003) is lower than the world’s best practice efficiency range as reported by the AGO (2001) which is between 35.5% to 37.6%. A more recent electricity generation cost study by Bedilion et al. (2009) assumed a thermal efficiency of 33.2% HHV (higher heating value) for OCGT technology. OCGT efficiencies can reach as high as 44% using current technology, as demonstrated with General Electric's (2014b) 100MW GE LMS100 simple cycle gas turbine.

The OCGT power generation system used in this analysis was assumed to have an efficiency similar to that reported by Bedilion et al. (2009), which was 33.2%. Dry air cooling technology was employed in all cases in Bedilion et al. (2009), which lowers the efficiency and produces more emissions than wet cooling due to the additional power required. When adjusted from dry cooling to wet cooling, the efficiency of OCGT systems increases by 2% to 35.2%

The emissions to air were calculated by multiplying emission factors with the amount of natural gas consumed. The greenhouse gas emission factors and factors for emissions to air for natural gas combustion in gas turbines can be found in Table A.35 and Table A.36 respectively in Appendix A.23. An example calculation for GHG is shown in Appendix A.24.

May (2003) provided key fuel usage data in OCGT systems which included fuel oil and automotive fuels such as diesel, petrol and LPG. Fuel oil is used in the turbines when the supply of natural gas is not adequate to meet generation requirements. Greenhouse gas emissions factors for combustion of fuel oil is given in Table A.37, while factors for the other emissions to air were assumed to be similar to that of distillate consumption in gas turbines as shown in Table A.38. Both are located in Appendix A.23. Automotive fuels are used in the general operation of the power station and not directly consumed by the process. Emissions to air are calculated using emission factors for diesel engines in Table A.39 and Table A.40, petrol engines in Table A.41 and Table A.42, and LPG engines in Table A.43 and Table A.44.

Water impacts are assumed to be insignificant in the OCGT systems as no steam cycles are required. According to Smart & Aspinall (2009), water is usually used for NO_x control fogging or evaporative cooling to improve capacity, and the water usage for OCGT was 22 times less than that for CCGT.

The final material flows of the OCGT power station in Australia are shown in Table 4.28.

Table 4.28: Final material flow data for the generation of 1 net MWh of electricity from an OCGT power station

Inventory data	Units	Values	Category
Input			
Natural gas	t/MWh	1.99E-01	Feedstock
Fuel oil	t/MWh	2.33E-04	Auxiliary fuel
Diesel	t/MWh	3.01E-07	Automotive fuel
Petrol	t/MWh	3.82E-06	Automotive fuel
LPG	t/MWh	3.42E-06	Automotive fuel
Output			
CO_2	t/MWh	5.23E-01	Global Warming Potential
CH_4	t/MWh	4.86E-05	Global Warming Potential
N_2O	t/MWh	9.94E-07	Global Warming Potential
VOC	t/MWh	6.29E-06	Photochemical Oxidation Potential
CO	t/MWh	2.99E-04	Photochemical Oxidation Potential
NO_x	t/MWh	7.38E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/MWh	4.83E-06	Acidification Potential
PM_{10}	t/MWh	2.86E-05	Particulate Matter Formation

4.3.3.2.2. Closed cycle gas turbine (CCGT) technology

Similar to the OCGT systems, the LCI for CCGT systems is calculated manually using fuel data and emission factors. May (2003) has published LCI for CCGT power station data from Victoria with efficiencies averaging around 50.1%. The LCI data is located in Appendix A.22.

The average efficiency of 50.1% reported by May (2003) is within the world's best practice efficiency range reported by AGO (2001), which is between 46.7% to 52%. Bedilion et al. (2009) used a similar but slightly lower thermal efficiency of 49.5% HHV for CCGT technology. Efficiencies are expected to approach 60% HHV. The increase in efficiency are due to improved technologies such as the development and commercialisation of higher firing temperature gas turbines, e.g. H-class turbines with firing temperatures approaching 1420°C, which provide higher thermal efficiency. General Electric (2014a) demonstrated a CCGT plant design with an expected baseload efficiency of 60%.

The CCGT efficiency from Bedilion et al. (2009) was chosen for this analysis. After adjusting from dry cooling to wet cooling, the efficiency of CCGT systems is raised by 2% to 51.5%. The emissions to air for the CCGT power generation system used in this analysis were calculated based on this efficiency using the emission factors given in Table A.35 and Table A.36 for natural gas combustion in gas turbines. Auxiliary and automotive fuel data and assumptions were based off data from May (2003). The calculation approach was similar to that shown in Appendix A.24.

The low quality water usage reported by May (2003) for cooling assumed a once-through cooling using water from local sources such as salt-water estuaries. To maintain consistency, this study assumes recirculated cooling water systems are used for all downstream systems. Recirculated cooling water systems use less freshwater than once-through cooling, and is based on figures from Smart & Aspinall (2009). The recirculated cooling water requirements for a CCGT system are shown in Appendix A.25.

The final material flows of the CCGT power station in Australia are shown in Table 4.29.

Table 4.29: Final material flow data for the generation of 1 net MWh of electricity from a CCGT power station

Inventory data	Units	Values	Category
Input			
Natural gas	t/MWh	1.36E-01	Feedstock
Fuel oil	t/MWh	1.48E-04	Auxiliary fuel
Diesel	t/MWh	1.12E-07	Automotive fuel
Petrol	t/MWh	1.42E-06	Automotive fuel
LPG	t/MWh	1.28E-06	Automotive fuel
Cooling water makeup	t/MWh	8.06E-01	Freshwater Withdrawal
Boiler feedwater makeup	t/MWh	8.06E-02	Freshwater Withdrawal
Output			
Cooling water blowdown	t/MWh	1.26E-01	Saline Water Generation
Steam blowdown	t/MWh	8.06E-02	Saline Water Generation
CO_2	t/MWh	3.58E-01	Global Warming Potential
CH_4	t/MWh	3.33E-05	Global Warming Potential
N_2O	t/MWh	6.81E-07	Global Warming Potential
VOC	t/MWh	4.27E-06	Photochemical Oxidation Potential
CO	t/MWh	2.04E-04	Photochemical Oxidation Potential
NO_x	t/MWh	5.06E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/MWh	3.30E-06	Acidification Potential
PM_{10}	t/MWh	1.96E-05	Particulate Matter Formation

4.3.3.3. ECONOMIC FLOWS

4.3.3.3.1. Capital costs

Capital costs for OCGT power stations were adapted from Bedilion et al. (2009). A 115 MW OCGT power station with an efficiency of 33.2% HHV had a direct plant cost of 2009A$72 million. Similarly, the direct plant cost for a 711 MW CCGT power station with an efficiency of 49.6% HHV was estimated by Bedilion et al. (2009) to be 2009A$653 million. These capital costs are adjusted based on their cooling system configurations and for inflation.

Engineering and construction management costs, assumed to be 25% of direct plant costs, were first factored into the capital cost of the OCGT and CCGT power station.

The capital costs in Bedilion et al. (2009) were reported for dry air cooling systems. To adjust from dry cooling to wet cooling, capital cost factors from Smart & Aspinall (2009) were used, where the difference between dry cooling and wet cooling capital cost factors were $36/kW. The switch to wet cooling will increase the efficiency of OCGT systems by 2% to 35.2%, and the efficiency of CCGT systems by 2% to 51.6%.

The capital costs of OCGT and CCGT plants were reported by Bedilion et al. (2009) in 2009 Australian dollars. These were adjusted to 2012 Australian dollars.

All peaking electricity generation technologies are brought to a common capacity of 150 MW, while baseload electricity generation technologies are brought to a common capacity of 750 MW. To allow for economies of scale when adjusting to a common basis, a factor of 0.76 is used for CCGT projects. This is observed when a range of CCGT projects in Australia were plotted on a capital cost versus capacity graph in Figure 4.18. Data sources for each point are located in Appendix A.26.

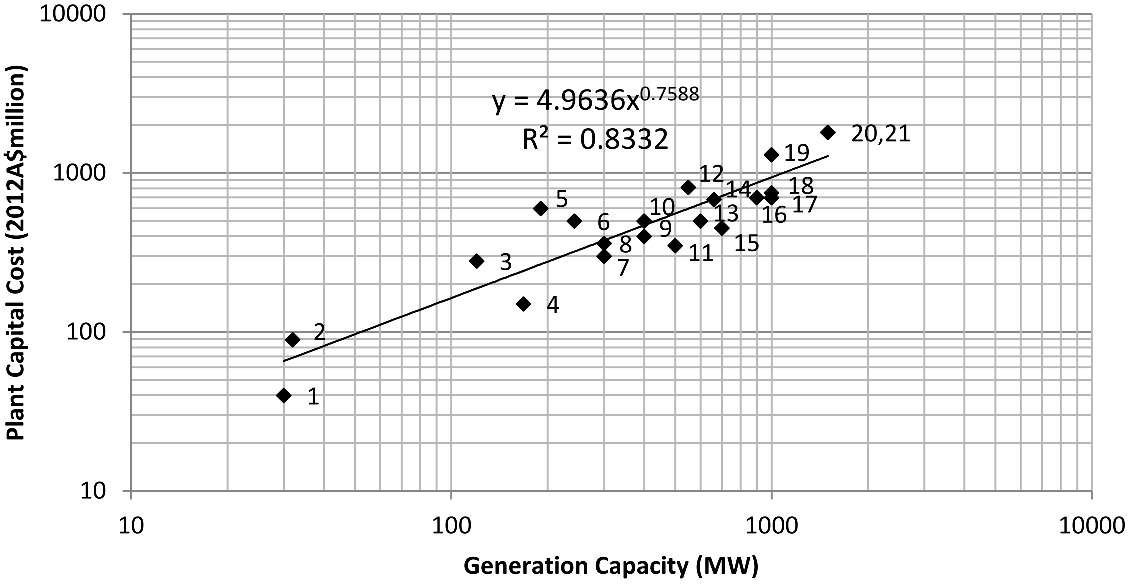


Figure 4.18: Fixed capital investment of CCGT projects in 2012 Australian dollars as a function of capacity in MW. Note: The projects included in the diagram can be found in Appendix A.26.

This gives the final capital costs of the baseline OCGT and CCGT technologies as reported in Table 4.30. Both natural gas and CSG can be used in similar OCGT and CCGT systems; hence there is no difference in capital costs for these two fuels.

Table 4.30: Total plant capital costs of gas-fired technologies after adjustment (Costs are expressed in 2012A$)

Technology	OCGT	CCGT
Sent-out capacity (MW)	150	750
Total plant capital cost (A$million)	114	905
Total plant capital cost (A$/kW)	760	1,210

4.3.3.3.2. Operating costs

The operating costs of OCGT and CCGT power stations are estimated using cost models. The main difference between natural gas and CSG system operating costs are due to the difference in transfer prices. Four tables are presented in this section. Table 4.31 and Table 4.32 present the operating costs for OCGT systems using natural gas and CSG respectively. Table 4.33 and Table 4.34 present the operating costs for CCGT systems using natural gas and CSG respectively.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For OCGT, there is one process zone, which is the gas turbine. For CCGT, there are two process zones, which are the gas turbine and the steam turbine. An additional operator is required for the control room. Hence, OCGT will require two process operators, while CCGT requires three in total.

Table 4.31: Operating cost model for OCGT using natural gas (Costs are expressed in 2012A$)

Plant capacity	150	MW			
Plant availability	10%				
Annual actual production	131	GWh/yr			
Fixed capital investment	114	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per MWh ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Natural gas fuel	t	0.199	179	4.66	35.48
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	t	-	0.0770	-	-
Process water	t	-	1.50	-	-
Total variable costs				**4.66**	**35.48**
Operating labour		No.	Salary ($/yr)		
Operators/shift		2			
Shift teams		5			
Total shift operators		10	110,000	1.10	8.37
Total operating labour costs				**1.10**	**8.37**
Payroll overheads		40	% total operating labour cost	0.44	3.35
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.23	1.76
Maintenance labour		1		1.14	8.66
Maintenance materials		1		1.14	8.66
Consumables store			10	0.15	1.17
Plant overheads			100	1.54	11.72
Laboratory			10	0.15	1.17
Insurance		1		1.14	8.66
Property taxes		1		1.14	8.66
Total fixed costs				**8.17**	**62.17**
Total manufacturing costs				**12.83**	**97.65**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	0.58	**4.39**
Marketing costs		5	Total production cost	0.72	**5.49**
Research and development costs		2	Total production cost	0.29	**2.19**
General expenses				**1.59**	**12.07**
Total product cost				**14.42**	**109.72**

Table 4.32: Operating cost model for OCGT using CSG (Costs are expressed in 2012A$)

				Annual cost	Cost per MWh
Plant capacity	150	MW			
Plant availability	10%				
Annual actual production	131	GWh/yr			
Fixed capital investment	114	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per MWh ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Coal seam gas fuel	t	0.199	138	3.61	27.44
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	t	-	0.0770	-	-
Municipal water	t	-	1.50	-	-
Total variable costs				**3.61**	**27.44**
Operating labour		No.	Salary ($/yr)		
Operators/shift		2			
Shift teams		5			
Total shift operators		10	110,000	1.10	8.37
Total operating labour costs				**1.10**	**8.37**
Payroll overheads		40	% total operating labour cost	0.44	3.35
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.23	1.76
Maintenance labour		1		1.14	8.66
Maintenance materials		1		1.14	8.66
Consumables store			10	0.15	1.17
Plant overheads			100	1.54	11.72
Laboratory			10	0.15	1.17
Insurance		1		1.14	8.66
Property taxes		1		1.14	8.66
Total fixed costs				**8.17**	**62.17**
Total manufacturing costs				**11.78**	**89.61**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	0.53	**4.03**
Marketing costs		5	Total production cost	0.66	**5.03**
Research and development costs		2	Total production cost	0.26	**2.01**
General expenses				**1.46**	**11.08**
Total product cost				**13.23**	**100.69**

Table 4.33: Operating cost model for CCGT using natural gas (Costs are expressed in 2012A$)

Plant capacity	750 MW				
Plant availability	85%				
Annual actual production	5,590 GWh/yr				
Fixed capital investment	905 $ million				
Capital exponent,ψ (I=αQψ)	0.7588				
Cost year	2012 AUD$				
Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Natural gas fuel	t	0.136	179	135.89	24.31
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	m3	42.0	0.0770	18.08	3.23
Demineralised water	t	0.08	1.50	0.11	0.12
Total variable costs				**154.08**	**27.67**
Operating labour		No.	Salary ($/yr)		
Operators/shift		3			
Shift teams		5			
Total shift operators		15	110,000	1.65	0.30
Total operating labour costs				**1.65**	**0.30**
Payroll overheads		40	% total operating labour cost	0.66	0.12
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.35	0.06
Maintenance labour		1		9.05	1.62
Maintenance materials		1		9.05	1.62
Consumables store			10	0.23	0.04
Plant overheads			100	2.31	0.41
Laboratory			10	0.23	0.04
Insurance		1		9.05	1.62
Property taxes		1		9.05	1.62
Total fixed costs				**41.63**	**7.45**
Total manufacturing costs				**195.71**	**35.11**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	8.80	**1.57**
Marketing costs		5	Total production cost	10.99	**1.97**
Research and development costs		2	Total production cost	4.40	**0.79**
General expenses				**24.19**	**4.33**
Total product cost				**219.90**	**39.44**

Table 4.34: Operating cost model for CCGT using CSG (Costs are expressed in 2012A$)

Plant capacity	750 MW				
Plant availability	85%				
Annual actual production	5,590 GWh/yr				
Fixed capital investment	905 $ million				
Capital exponent,ψ (I=αQψ)	0.7588				
Cost year	2012 AUD$				
Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Coal seam gas fuel	t	0.136	138	105.13	18.81
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	m3	42.0	0.0770	18.08	3.23
Demineralised water	t	0.08	1.50	0.11	0.12
Total variable costs				**123.31**	**22.16**
Operating labour		No.	Salary ($/yr)		
Operators/shift		3			
Shift teams		5			
Total shift operators		15	110,000	1.65	0.30
Total operating labour costs				**1.65**	**0.30**
Payroll overheads		40	% total operating labour cost	0.66	0.12
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.35	0.06
Maintenance labour		1		9.05	1.62
Maintenance materials		1		9.05	1.62
Consumables store			10	0.23	0.04
Plant overheads			100	2.31	0.41
Laboratory			10	0.23	0.04
Insurance		1		9.05	1.62
Property taxes		1		9.05	1.62
Total fixed costs				**41.63**	**7.45**
Total manufacturing costs				**164.94**	**29.61**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	7.41	**1.33**
Marketing costs		5	Total production cost	9.27	**1.66**
Research and development costs		2	Total production cost	3.71	**0.66**
General expenses				**20.39**	**3.65**
Total product cost				**185.33**	**33.26**

4.3.3.3.3. Total operating costs

Table 4.35 summarises the annualised capital costs and cash operating costs of electricity generation from gas-fired power stations, which combine to form the total operating costs.

Table 4.35: Total operating costs for OCGT and CCGT power stations (Costs are expressed in 2012A$)

Technology		OCGT		CCGT	
Capacity (MW)		150		750	
Output (MWh/yr)		1.31×10^5		5.58×10^6	
Annualised capital costs ($/MWh)		91.8		17.2	
Feedstock type		NG	CSG	NG	CSG
Cash operating costs	Variable costs ($/MWh)	35.5	27.4	27.7	22.2
	Fixed costs ($/MWh)	62.2	62.2	7.45	7.45
	Other costs ($/MWh)	12.1	11.1	4.33	3.65
	Total ($/MWh)	110	101	39.5	33.3
Total operating costs ($/MWh)		202	193	56.6	50.5

4.3.4. BLACK COAL

4.3.4.1. TECHNOLOGY DESCRIPTION

According to BREE (2013e), only three states utilise black coal for grid electricity generation: New South Wales (including the Australian Capital Territory), Queensland and Western Australia. The dominant technology used in black coal power stations is the pulverised coal steam turbine (PCST) technology. Recent black coal plants constructed in Australia utilised the efficient super-critical boiler technology, such as Callide C (the first in Australia), Tarong North, Millmerran, and Kogan Creek (Smart & Aspinall 2009). Super-critical plants have higher operating pressures and temperatures, capital costs and efficiencies than sub-critical plants. Super-critical plants also are more suited for operation at full load to deliver baseload power, while sub-critical plants are more suitable to meet fluctuating electricity demands at different times of the day (Bedilion et al. 2009). A typical PCST power station is shown in Figure 4.19.

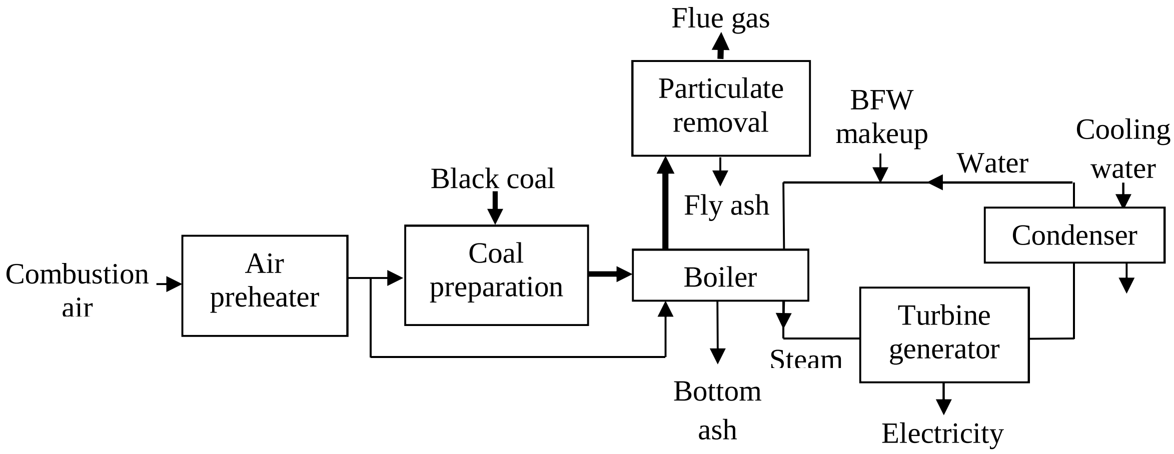


Figure 4.19: Process flow diagram for PCST power plant showing major inputs and outputs

Another black coal technology is the Integrated Gasification and Combined Cycle (IGCC) technology. The process involves production of synthesis gas from coal that can be cleaned and used to power a gas turbine as part of a combined cycle gas turbine configuration. This technology improves the sent-out efficiency of electricity generated from coal, and has reduced water consumption for cooling, as two thirds of generated output is from the gas turbine and only one third is generated using a steam turbine. This technology also reduces emissions of sulphur dioxide, particulates and mercury (Bedilion et al. 2009). However, this technology is still in the development phase with a few plants operating in the world. The capital cost of the gasification process is usually high due to the cost of the gasifier, and it is still relatively water intensive when compared with gas-fired systems. There are no reported emission factors for electricity produced from coal via IGCC in Australia. A typical representation of the IGCC technology is shown in Figure 4.20.

Both PCST and IGCC systems are suited to substitute natural gas usage in baseload grid electricity generation.

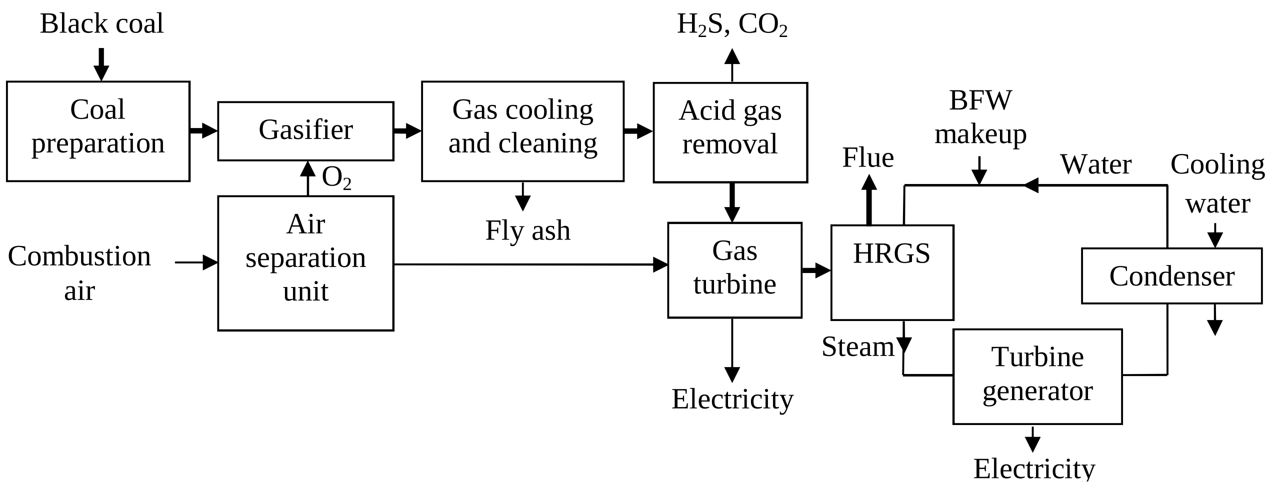


Figure 4.20: Process flow diagram for IGCC power plant showing major inputs and outputs

4.3.4.2. MATERIAL FLOWS

4.3.4.2.1. Pulverised coal steam turbine (PCST) technology

May (2003) reported material flows for coal-fired power generation in Australia, many of which are sub-critical power stations with the average efficiency of around 34%. These material flows are given in Appendix A.22. The efficiencies are lower than sub-critical power station standards set by world's best practice reported in AGO (2001) which are around 37.7%. AGO (2001) reported the world's best practice super-critical power station to have an efficiency of 41.7%.

The emissions to air in this analysis were assumed to be generated from a super-critical PCST power station with an efficiency of 38% HHV similar to that reported by Bedilion et al. (2009). Switching to water cooling technology raises the efficiencies for the PCST technology by 2% to 40%. The emissions to air were calculated using greenhouse gas emission factors for black coal combustion from Table A.45, and factors for other emissions to air from Table A.46. Both tables are found in Appendix A.23.

The combustion of auxiliary fuel and automotive fuels also contribute to the emissions to air in black coal power generation. Fuel oil is used to heat up the boiler and provide a stable flame to allow coal combustion to occur. Its usage is proportional to the black coal used to generate power. The emissions to air from combustion of fuel oil were calculated using the greenhouse gas emission factors from Table A.37 and Table A.38, which are both located in Appendix A.23. The usage of automotive fuels such as diesel and petrol are adapted from May (2003). These fuel usages are multiplied with emission factors for combustion of diesel and petrol from Table A.39, Table A.40, Table A.41 and Table A.42 in Appendix A.23. The calculation approach was similar to that shown in Appendix A.24.

Emissions from coal processes that contribute to acidification can be mitigated by using the appropriate flue gas desulphurisation process. NETL (2010) employs limestone to remove SO_2 from the flue gas prior to release to the environment and in the process produce gypsum ($CaSO_4$). However, this is not practised in Australia due to the low sulphur content of Australian black coal (May 2003). The addition of the desulphurisation process will also increase the capital and operating costs of grid electricity generation. as well as the secondary environmental impacts due to limestone acquisition, waste gypsum and increased energy requirements.

Makeup water, blowdown losses and evaporation losses are adapted from Smart & Aspinall (2009) and are found in Appendix A.25.

The final material flow data for a pulverised super-critical power station in Australia are shown in Table 4.36.

Table 4.36: Final material flow data for a super-critical PCST power station

Inventory data	Units	Value	Category
Input			
Black coal	t/MWh	3.63E-01	Feedstock
Fuel oil	t/MWh	2.21E-04	Auxiliary fuel
Diesel	t/MWh	9.95E-06	Automotive fuel
Petrol	t/MWh	1.09E-05	Automotive fuel
Cooling water makeup	t/MWh	1.90	Freshwater Withdrawal
Boiler feedwater makeup	t/MWh	1.00E-01	Freshwater Withdrawal
Output			
Cooling water blowdown	t/MWh	2.00E-01	Saline Water Generation
Steam blowdown	t/MWh	1.00E-01	Saline Water Generation
CO_2	t/MWh	7.82E-01	Global Warming Potential
CH_4	t/MWh	1.27E-05	Global Warming Potential
N_2O	t/MWh	5.72E-06	Global Warming Potential
VOC	t/MWh	6.64E-09	Photochemical Oxidation Potential
CO	t/MWh	9.10E-05	Photochemical Oxidation Potential
NO_x	t/MWh	1.78E-03	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/MWh	4.71E-09	Acidification Potential
PM_{10}	t/MWh	1.28E-04	Particulate Matter Formation
Ash	t/MWh	7.70E-02	Solid Waste Generation

4.3.4.2.2. Integrated gasification and combined cycle (IGCC)

May (2003) reported material data for IGCC technology in Appendix A.22, which was adapted from the U.S. Department of Energy. The black coal feedstock input is significantly lower than the IGCC systems reported in NETL (2010a), suggesting a net efficiency of almost 59%, which was too high for even the most efficient IGCC technology.

Other IGCC environmental and cost data in the Australian context can be found in Bedilion et al. (2009) and Falcke et al. (2011) and are given in Table 4.37. Bedilion et al. (2009) reported net efficiencies of IGCC that were typically between 38 to 41% HHV, which can increase by 6.7% using 2030 technology. An Australian IGCC study by Falcke et al. (2011) reported a net efficiency of 32% LHV. Smart and Aspinall (2009) reported that IGCC efficiencies of 50% are possible.

The efficiency of the IGCC for this analysis was chosen to be 39.4% based on Bedilion et al. (2009). Switching to water cooling technology raises the efficiency of the IGCC technology by 2%, bringing the efficiency of IGCC up to 41.4%.

Table 4.37: Material flow data for an IGCC coal power station in Australia (Bedilion et al. 2009, Falcke et al. 2011)

Inventory data	**Bedilion et al. (2009)**		**Falcke et al. (2011)**	
	Input	**Output**	**Input**	**Output**
Electricity	2.14E-01	1	2.46E-01	1
	Input	**Output**	**Input**	**Output**
Black coal	3.68E-01	0	4.62E-01	0
Low quality water	2.05E-01	0	20.8	0
Wastewater				4.02E-01
CO_2	0	8.12E-01	0	1.13
NO_x	0	1.20E-05	0	6.24E-05
SO_2	0	2.00E-04	0	5.78E-05

Due to the lack of definitive environmental and cost data for IGCC in Australia, the material flow data were calculated using emission factors adapted from NETL (2012) that allow for adjustment of emissions according to different efficiencies. Based on a chosen efficiency of 39.4% HHV for IGCC, the material data for IGCC in this analysis was calculated using emission factors in Table A.49 in Appendix A.23. This efficiency was equal to that chosen for PCST, and is the highest in the efficiency range reported by Smart and Aspinall (2009). The calculation approach was similar to that shown in Appendix A.24.

The material flow data from NETL (2012) is representative of a U.S. IGCC plant burning Pittsburgh No.8 coal (see Appendix A.27 for coal composition). The material flow data can be adjusted by replacing the U.S. coal with the Australian reference black coal (see Section 4.1.4 for Australian coal composition) and recalculating the mass balance of the IGCC plant. This procedure is summarised in Appendix A.28.

Makeup water, blowdown losses and evaporation losses are adapted from Smart & Aspinall (2009) and are found in Appendix A.25.

The final material flow data for an IGCC power station in Australia are shown in Table 4.38.

Table 4.38: Final material flow data for the generation of 1 net MWh electricity from an IGCC power station

Inventory data	**Units**	**Value**	**Category**
Input			
Black coal	t/MWh	3.56E-01	Feedstock
Cooling water makeup	t/MWh	1.12	Freshwater Withdrawal
Boiler feedwater makeup	t/MWh	1.12E-01	Freshwater Withdrawal
Output			
Cooling water makeup	t/MWh	1.75E-01	Saline Water Generation
Steam blowdown	t/MWh	1.12E-01	Saline Water Generation
CO_2	t/MWh	7.46E-01	Global Warming Potential
CH_4	t/MWh	3.11E-06	Global Warming Potential
N_2O	t/MWh	3.58E-09	Global Warming Potential
VOC	t/MWh	2.20E-08	Photochemical Oxidation Potential
CO	t/MWh	3.93E-07	Photochemical Oxidation Potential
NO_x	t/MWh	2.41E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/MWh	9.67E-06	Acidification Potential
PM_{10}	t/MWh	3.14E-05	Particulate Matter Formation
Ash	t/MWh	6.99E-02	Solid Waste Generation

4.3.4.3. ECONOMIC FLOWS

4.3.4.3.1. Capital costs

Bedilion et al. (2009) reported that a 750 MW super-critical pulverised coal power station without NO_x and SO_2 controls with an efficiency of 38% HHV had a direct plant cost of around 2009A$1.69 billion Bedilion et al. (2009) also reported the direct plant cost of a 576 MW IGCC power station with a higher efficiency of 39.4% HHV to be around 2009A$2.67 billion. An estimate for engineering and construction management costs, assumed to be 25% of direct plant costs, was added to the direct capital cost to calculate the total capital costs.

To adjust from dry cooling to wet cooling, capital cost factors from Smart & Aspinall (2009) were used, where the difference between dry cooling and wet cooling capital cost factors were $66/kW for PCST. No cost factors were published for IGCC, so the PCST cost factors were adopted instead. Switching to water cooling technology raises the efficiencies for the PCST technology by 2% to 40%, while switching to water cooling technology raises the efficiencies for the IGCC technology by 2%, bringing the efficiency of IGCC up to 41.4%.

As Bedilion et al. (2009) reported the capital cost of PCST and IGCC to be in 2009 Australian dollars, this was adjusted to 2012 Australian dollars.

PCST and IGCC systems are both baseload grid electricity generation technologies. In order to enable substitution with natural gas CCGT plants, the plant capital costs are to a common capacity of 750 MW.

The capital costs of the PCST and IGCC technologies are summarised in Table 4.39.

Table 4.39: Total plant capital costs of black coal-fired technologies after adjustment

	PCST	IGCC
Sent-out capacity (MW)	750	750
Total plant cost ($mil)	2,270	3,700
Total plant cost ($/kW)	3,030	4,920

4.3.4.3.2. Operating costs

Operating cost models were used to estimate the operating costs of PCST and IGCC power stations. The operating costs for PCST are given in Table 4.40 and the operating costs for IGCC are given in Table 4.41.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For PCST, there are three process zones, which are the coal preparation, boiler and steam turbine system as one process zone and pollution control. For IGCC, there are seven process zones, which are the coal preparation, air separation unit, gasifier, syngas clean-up, acid gas removal, gas turbine and steam turbine. An additional operator is required for the control room. Hence, PCST will require four process operators, while IGCC requires eight in total.

Table 4.40: Operating cost model for a PCST power station using black coal (Costs are expressed in 2012A$)

Plant capacity	750	MW			
Plant availability	85%				
Annual actual production	5,590	GWh/yr			
Fixed capital investment	2,274	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Black coal fuel	t	0.363	33.1	67.28	12.04
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	m3	99.0	0.0770	42.59	7.62
Demineralised water	t	0.10	1.50	0.84	0.15
Total variable costs				**110.71**	**19.81**
Operating labour		No.	Salary ($/yr)		
Operators/shift		4			
Shift teams		5			
Total shift operators		20	110,000	2.20	0.39
Total operating labour costs				**2.20**	**0.39**
Payroll overheads		40	% total operating labour cost	0.88	0.16
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.46	0.08
Maintenance labour		1		22.74	4.07
Maintenance materials		1		22.74	4.07
Consumables store			10	0.31	0.06
Plant overheads			100	3.08	0.55
Laboratory			10	0.31	0.06
Insurance		1		22.74	4.07
Property taxes		1		22.74	4.07
Total fixed costs				**98.20**	**17.57**
Total manufacturing costs				**208.90**	**37.37**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	9.39	**1.68**
Marketing costs		5	Total production cost	11.74	**2.10**
Research and development costs		2	Total production cost	4.69	**0.84**
General expenses				**25.82**	**4.62**
Total product cost				**234.72**	**41.99**

Table 4.41: Operating cost model for an IGCC power station using black coal (Costs are expressed in 2012A$)

	750	MW			
Plant availability	85%				
Annual actual production	5,590	GWh/yr			
Fixed capital investment	3,696	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Black coal fuel	t	0.356	33.1	66.02	11.81
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	m3	58.5	0.0770	25.17	4.50
Demineralised water	t	0.11	1.50	0.94	0.17
Total variable costs				**92.13**	**16.48**
Operating labour		No.	Salary ($/yr)		
Operators/shift		4			
Shift teams		5			
Total shift operators		20	110,000	2.20	0.39
Total operating labour costs				**2.20**	**0.39**
Payroll overheads		40	% total operating labour cost	0.88	0.16
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.46	0.08
Maintenance labour		1		36.96	6.61
Maintenance materials		1		36.96	6.61
Consumables store			10	0.31	0.06
Plant overheads			100	3.08	0.55
Laboratory			10	0.31	0.06
Insurance		1		36.96	6.61
Property taxes		1		36.96	6.61
Total fixed costs				**155.08**	**27.75**
Total manufacturing costs				**247.21**	**44.23**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	11.11	**1.99**
Marketing costs		5	Total production cost	13.89	**2.48**
Research and development costs		2	Total production cost	5.56	**0.99**
General expenses				**30.55**	**5.47**
Total product cost				**277.77**	**49.69**

4.3.4.3.3. Total operating costs

Table 4.42 summarises the annualised capital costs and cash operating costs of electricity generation from gas-fired power stations, which combine to form the total operating costs.

Table 4.42: Operating cost of electricity from PCST and IGCC (Costs are expressed in 2012A$)

Technology		PCST	IGCC
Capacity (MW)		750	
Output (MWh/yr)		5.58×10^6	
Annualised capital costs ($/MWh)		43.2	70.2
Cash operating costs	Variable costs ($/MWh)	19.8	16.5
	Fixed costs ($/MWh)	17.6	27.8
	Other costs ($/MWh)	4.62	5.47
	Total ($/MWh)	42.0	49.7
Total operating costs ($/MWh)		85.2	120

4.3.5. DIESEL

4.3.5.1. MATERIAL FLOWS

Diesel-fired engines were assumed to have a higher efficiency of 39% (BREE 2013c). This determines how much diesel is consumed to produce 1 MWh of electricity. The greenhouse gas emissions are estimated using emission factors for diesel in Table A.39 and the other emissions to air are estimated using emission factors in Table A.50, both of which are located in Appendix A.23. Similar to OCGT, it was assumed that there was no water usage in diesel engines for grid electricity generation.

The final material flow data for a diesel-fired power station in Australia are shown in Table 4.43.

Table 4.43: Final material flow data for the generation of 1 MWh of a diesel-fired power station

Inventory data	Units	Value	Category
Input			
Diesel	t/MWh	2.09E-01	Fuel
Diesel	t/MWh	3.01E-07	Automotive fuel
Petrol	t/MWh	3.82E-06	Automotive fuel
LPG	t/MWh	3.42E-06	Automotive fuel
Output			
CO_2	t/MWh	6.73E-01	Global Warming Potential
CH_4	t/MWh	1.32E-05	Global Warming Potential
N_2O	t/MWh	5.96E-06	Global Warming Potential
VOC	t/MWh	3.84E-04	Photochemical Oxidation Potential
CO	t/MWh	3.34E-03	Photochemical Oxidation Potential
NO_x	t/MWh	7.90E-03	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/MWh	1.23E-05	Acidification Potential
PM_{10}	t/MWh	4.26E-04	Particulate Matter Formation

4.3.5.2. CAPITAL COSTS

As a rule of thumb, diesel internal combustion (IC) engines are less expensive than natural gas engines as gas engines have additional accessories installed on the engine to accommodate natural gas as a fuel source. According to EPRI (2003), the capital cost of a distributed generation system in the U.S. can be estimated using Equation 4.15.

$$I = (437)Q - (0.0094)Q^2 \qquad \text{(Equation 4.15)}$$

where I = Total project cost, in US dollars
Q = Project size, kW

This equation was formulated using a selection of diesel generators ranging from 1 MW to 10 MW. For a 10 MW diesel fuelled generation system, the estimated project capital cost will be US$3,430,000. 55% of the project capital cost is attributed to the generator set, 8% to the building enclosures, 9% to switchboards and controls, 2% for emissions controls, while installation, indirect and miscellaneous costs take up nearly 26% of project capital costs.

Jacobson et al. (2013) have similarly calculated the capital costs of diesel generators ranging from 10 kW to 1000 kW as part of a data collection of diesel generators in South Australia. Table 4.44 shows the replacement costs or capital costs of diesel generators.

Table 4.44: Replacement costs of diesel generators in South Australia (Jacobson et al. 2013)

Generator size (kW)	Cost (A$/kW)	Replacement cost (A$)
10	0.70	7,000
50	0.60	30,000
100	0.50	50,000
1000	0.40	400,000

Using this information, the capital cost of diesel generators was assumed to follow the Equation 4.16.

$$I = 934Q^{0.88} \qquad \text{(Equation 4.16)}$$

where I = Replacement cost of diesel generator, in Australian dollars
Q = Generator size, kW

Using extrapolation, it can be estimated that a diesel generator with a capacity of 10 MW will have a cost of around A$0.30/kW. This gives a replacement cost of A$3.09 million, which is approximately 10% lower than the EPRI diesel generator project cost.

For this analysis, Equation 4.16 was used to estimate the capital cost based on the capacity of the diesel-fired power station. For a generation capacity of 150 MW, the capital cost of the diesel-fired power station was calculated to be $41.9 million. This estimate includes an estimate for engineering and construction management costs, which was assumed to be 25% of direct plant costs. The capital cost is reported in Table 4.45.

Table 4.45: Total plant capital costs of diesel-fired technologies after adjustment

	DIC
Sent-out capacity (MW)	150
Total plant cost ($mil)	41.9
Total plant cost ($/kW)	279

4.3.5.3. OPERATING COSTS

Operating cost models were used to estimate the operating costs of diesel-fired power stations. The operating costs for diesel-fired power stations are given in Table 4.46.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For diesel IC, there is one process zone, which is the diesel engine. Two additional operators are required, one for the control room and one for liquids handling. Hence, diesel IC will require three process operators in total.

Table 4.46: Operating cost model for diesel-fired engine power stations (Costs are expressed in 2012A$)

Plant capacity	150	MW			
Plant availability	10%				
Annual actual production	131	GWh/yr			
Fixed capital investment	41.9	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per MWh ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Natural gas feedstock	t	0.209	888	24.44	186.01
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	t	-	0.0770	-	-
Process water	t	-	1.50	-	-
Total variable costs				**24.44**	**186.01**
Operating labour		No.	Salary ($/yr)		
Operators/shift		3			
Shift teams		5			
Total shift operators		15	119,000	1.79	13.58
Total operating labour costs				**1.79**	**13.58**
Payroll overheads		40	% total operating labour cost	**0.71**	5.43
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.37	2.85
Maintenance labour		1		0.42	3.19
Maintenance materials		1		0.42	3.19
Consumables store			10	0.25	1.90
Plant overheads			100	2.50	19.02
Laboratory			10	0.25	1.90
Insurance		1		0.42	3.19
Property taxes		1		0.42	3.19
Total fixed costs				**7.55**	**57.45**
Total manufacturing costs				**31.99**	**243.46**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	1.44	**10.94**
Distributing and marketing costs		5	Total production cost	1.80	**13.68**
Research and development costs		2	Total production cost	0.72	**5.47**
General expenses				**3.95**	**30.09**
Total product cost				**35.94**	**273.55**

4.3.5.4. TOTAL OPERATING COSTS

Table 4.47 summarises the annualised capital costs and cash operating costs of electricity generation from gas-fired power stations, which combine to form the total operating costs.

Table 4.47: Operating cost of electricity from diesel engines (Costs are expressed in 2012A$)

Technology		DIC
Capacity (MW)		150
Output (MWh/yr)		1.31×10^5
Annualised capital costs ($/MWh)		33.8
Cash operating costs	Variable costs ($/MWh)	186
	Fixed costs ($/MWh)	57.5
	Other costs ($/MWh)	30.1
	Total ($/MWh)	274
Total operating costs ($/MWh)		307

4.3.6. SUBSTITUTION IMPACTS FOR GRID ELECTRICITY GENERATION

In the event of a natural gas scarcity in baseload grid electricity generation, either CCGT systems were replaced with PCST systems for the case where natural gas is substituted with black coal or natural gas was substituted with CSG as the fuel for CCGT systems. PCST systems were chosen in favour of IGCC systems because they are relatively more mature and are available at very high efficiencies. For peaking grid electricity generation, either OCGT systems were replaced with diesel engines or natural gas was substituted with CSG as the fuel for OCGT systems. Costs associated with CO_2 capture and storage were not considered in this analysis.

Table 4.48 shows the environmental and economic impact indicators for substitution in both baseload and peaking grid electricity generation. The environmental impacts are normalised to Australian emissions.found in Table 4.2. Substitution of natural gas with black coal in baseload grid electricity generation will result in an increase in impacts for all categories for all categories except photochemical oxidation potential and associated water withdrawal. Using black coal for grid electricity generation recorded a higher photochemical oxidation potential than when using natural gas due to higher emissions of NO_x in coal power generation. However, the increase was smaller in magnitude when compared to the resulting decrease in photochemical oxidation impacts in the upstream section after substitution. The natural gas upstream section releases more photochemical oxidation emissions due to natural gas combustion in gas-powered turbines and regeneration of dehydration units, while there no similar operations in the black coal upstream section. As for associated water withdrawal, this was greater for natural gas extraction and processing than for black coal extraction and processing. Hence, when natural gas is substituted for black coal, this results in a decrease in associated water withdrawal.

Substitution of natural gas with diesel in peaking grid electricity generation results in an increase in all impact categories as well, with the exception of freshwater withdrawal. The difference lies in the upstream section as there is no water withdrawal in the downstream section. The natural gas upstream section for peaking power generation reported relatively larger water consumption than for diesel, which may be due to large evaporation rates from the natural gas purification plants.

Substitution with CSG results in similar substitution impact indicators for baseload and peaking grid electricity generation. All the changes in impacts are in the upstream section and none are reported for the downstream section. This is due to the assumption that natural gas and CSG are virtually identical when arriving at the downstream plant. Identical results are reported for all sectors that follow later in the thesis. All categories reported decreases except for the associated water withdrawal and solid waste generation categories which reported increases instead. This is due to the production of large amounts of CSG water during CSG extraction and salt waste from CSG water treatment which is sent to the landfill.

Substitution with black coal produces a higher capital cost penalty for every t natural gas substituted than substitution with diesel. On the other hand, substitution with diesel produces a higher total operating cost for every t natural gas substituted as compared to substitution with black coal. This is due to the high cost of diesel fuel. Substitution of natural gas with CSG will only cause a decrease in operating costs due to the lower transfer price of CSG compared to natural gas. No change in capital costs were anticipated for substitution with CSG as they can be used in both OCGT and CCGT systems as previously used with natural gas fuel.

Calculations to obtain the substitution impact indicators for the grid-electricity generation sector are located in Appendix A.29.

Table 4.48: Substitution impact indicators for baseload electricity generation in Australia

Option	Baseload grid electricity		Peaking grid electricity	
Feedstock	NG→BlC	NG→CSG	NG→D	NG→CSG
Technology	CCGT→PCST	CCGT	CCGT→IC	CCGT
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	+ 5.52E-09	- 1.14E-10	+ 1.53E-09	- 1.14E-10
Acidification Potential (ADP)	+ 3.46E-09	- 3.55E-10	+ 1.52E-08	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 3.61E-10	- 3.93E-09	+ 2.04E-08	- 3.93E-09
Particulate Matter Formation (PMF)	+ 9.11E-10	- 9.29E-11	+ 2.55E-09	- 9.29E-11
Freshwater Withdrawal (FWW)	+ 9.98E-11	- 3.50E-12	- 1.23E-12	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 1.44E-08	+ 4.31E-10	+ 1.44E-08
Saline Water Generation (CWG)	+ 1.06E-11	- 7.17E-13	+ 5.02E-15	- 7.17E-13
Solid Waste Generation (SWG)	+ 1.80E-07	+ 6.95E-10	+ 3.76E-11	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+ 317.0	-	+ 170.0	-
Cash operating costs	+ 18.7	- 45.5	+ 825.0	- 45.5
Total operating costs	+ 336.0	- 45.5	+ 995.0	- 45.5

Legend: ‘+’ sign denotes increase in impacts, ‘-‘ sign denotes decrease in impacts, NG=Natural Gas, BlC=Black Coal, CSG=Coal Seam Gas, D=Diesel, CCGT=Combined Cycle Gas Turbine, PCST=Pulverised Coal Steam Turbine, IC=Internal Combustion

Note: Environmental impact indicators include upstream and downstream impacts.

4.4. MINING

4.4.1. INTRODUCTION

Mining under the Australian and New Zealand Standard Industrial Classification (ANZSIC) (Trewin & Pink 2006) encompasses activities that extract coal and ores, crude petroleum, and natural gas. These activities include underground or open cut mining, dredging, quarrying, well operations, evaporation pans, recovery from ore dumps or tailings, and beneficiation activities[§§]. Exclusions were made for operations involved in refining and liquefying natural gas, smelting of mineral or ores, and in the manufacture of products with mineral origin such as coke or cement. These exclusions fall under the manufacturing category, with the exception of preliminary smelting of gold which was still considered to be part of the mining category (Trewin & Pink 2006). No reason was given for this particular inclusion.

Contradictions were observed regarding the inclusion of natural gas use in LNG manufacturing in the mining sector within the reports by the Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) and the Bureau of Resources and Energy Economics (BREE). Natural gas consumption in the various sectors in Australia is reported annually in the Australian Energy Statistics (AES) published by BREE. Changes were made in 2011 regarding the definition for the use of energy at the end-use stage used in the AES methodology (Che et al. 2013). This change involved separating conversion activities from their respective sectors. e.g. LNG manufacturing is removed from the mining end-use sector and re-classified under the manufacturing sector. As a result, the 2009 total natural gas consumption in the mining sector was reported to be 244.9 PJ (Cuevas-Cubria et al. 2011), and as a result of the change in methodology the 2010 natural gas usage was adjusted to 145.5 PJ (Penney et al. 2012). The 2011 total consumption of natural gas was reported to be 151 PJ out of a total energy consumption of 389 PJ in the mining sector (Stark et al. 2012, BREE 2013e).

However, the 2012 and 2013 Gas Market Reports (2012b, Cronshaw et al. 2013) have both reported that mining gas use includes use by LNG plants in the liquefaction process, quoting the 2013 edition of the AES as the data source. The 2013 edition of the AES reported that the 2012 natural gas usage was revised to 262.4 PJ out of a total energy consumption of 527.3 PJ for the mining sector (BREE 2013a, Che et al. 2013). This was higher than the reported figure of 173.1 PJ in the 2014 edition of the AES (BREE 2014). This difference may be due to the 2014 edition of the AES excluding the usage of natural gas in LNG manufacturing from the mining category.

BREE does not specify the exact areas in which natural gas was used in the mining industry. As the Australian mining division includes oil and gas extraction, it is possible that natural gas fuel used in the upstream stage (e.g. natural gas processing) is recorded as usage in the mining industry, but it is unclear if natural gas flared and vented is also counted as usage in the mining industry. Natural gas consumed in the gas supply and distribution networks are recorded as a separate category by BREE (2013a). For a typical remote mining site, electricity is usually consumed to run mining applications such as draglines, shovels, conveyors, drills, water pumping, crushers, processing plants and buildings, whereas diesel is consumed in mining vehicles. In hot climates, electricity may be needed for cooling as well. Several studies show that natural gas is not widely used directly in the mining process itself:

[§§] i.e. preparing, including crushing, screening, washing and flotation

- A survey was performed by the International Aluminium Institute (IAI) over bauxite mining operations in 2006, 54% of which belonged to Australia. According to IAI (2008), bauxite mining only requires a small amount of energy compared to refining of bauxite and electrolytic reduction of alumina. 69% of energy used to mine and transport the bauxite is from diesel fuel, and 24% is from fuel oil. Only 3% of energy usage was attributed to natural gas.
- Theiss (2011), an Australian construction, mining and services company, reported diesel, electricity, petrol and LPG usage for its projects but did not report any natural gas usage.
- Newcrest (2012) reported for its Telfer gold mine that liquid fuels such as diesel were used in both electricity generation and direct use while all natural gas usage was in electricity generation, not direct usage.

It is likely that the natural gas consumption in mining is attributed to generation of off-grid electricity and heating for mining purposes, which can become significant due to the number of remote mining sites in Australia. Many mining sites in Australia are generally located in remote areas where no grid electricity access is available. Figure 4.21 shows the locations of operating mines and power lines in Australia. It was observed that many operating mines are not connected to the power lines from the major electricity networks such as the South West Interconnected System (SWIS) or the National Electricity Market (NEM) connecting South Australia, Victoria, Tasmania, New South Wales and Queensland.

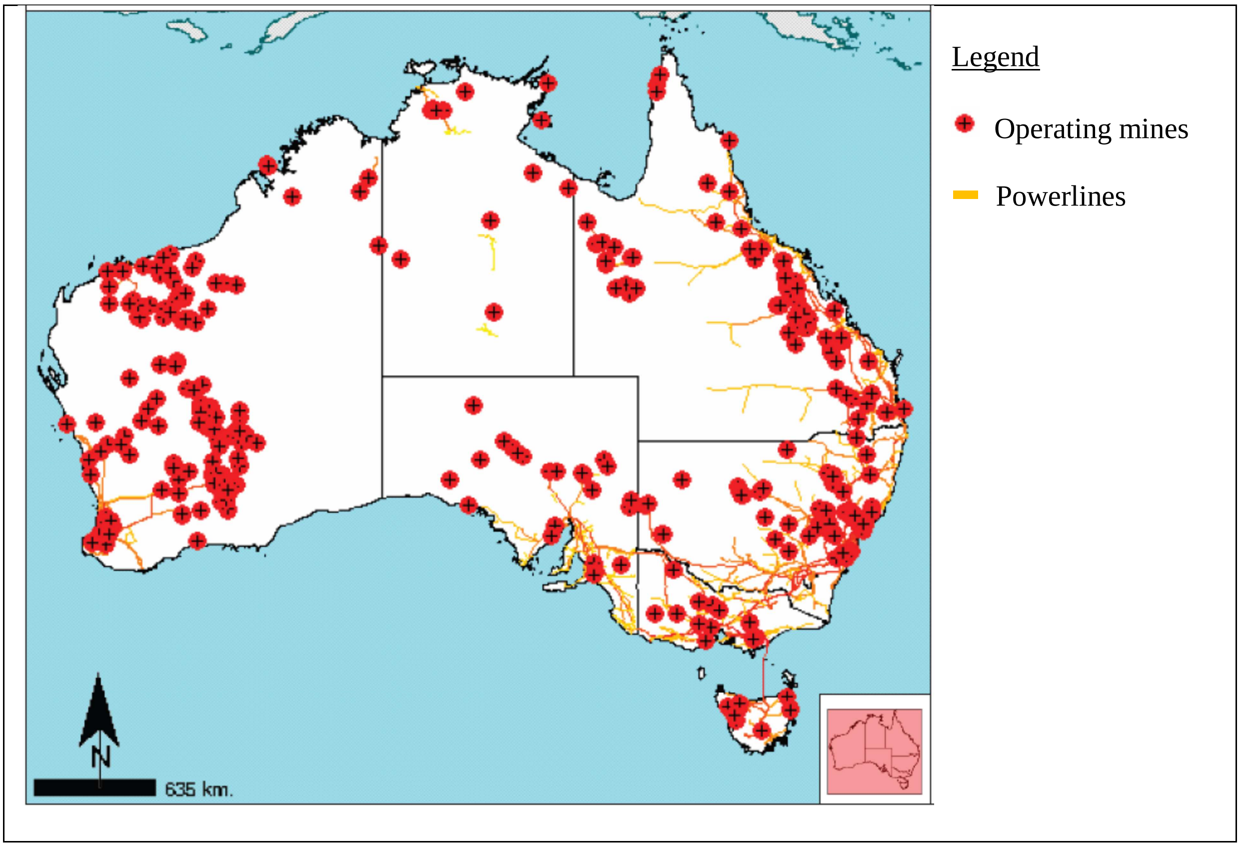


Figure 4.21: Map showing operating mines (dots) and powerlines (lines) in Australia.

Note: The diagram shows that the electricity transmission networks do not reach isolated mines that are far inland (e.g. Western Australia). Map was generated using online Mine Atlas mapping application found at http://www.australianminesatlas.gov.au/mapping/downloads.html, last accessed 1 June 2015).

Similarly, Figure 4.22 shows that railways do not pass through many of the remote mines. Substitution to black coal will require either the construction of either a transmission and distribution system or a coal transport railway system extending from the grid or coal mine to the remote mines. High infrastructure costs and significant distribution losses over distances may be factors that discourage mining companies from sourcing power from grid electricity or coal. Many of these remote mines opt to purchase natural gas to generate their own power and are usually located close to existing natural gas pipelines.

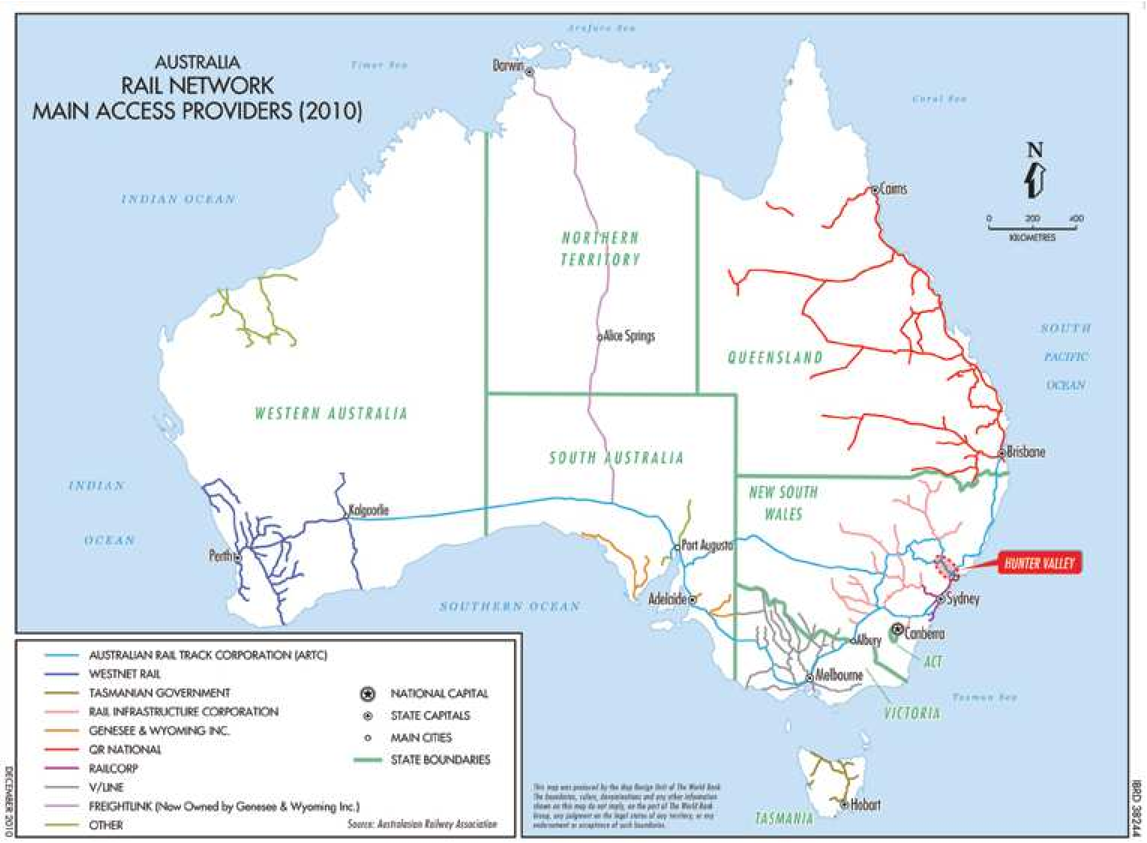


Figure 4.22: Australia's rail network (Australian Rail Track Corporation et al. 2010). The various railways do not connect isolated mines that are far inland.

Liquid fuels are the second most utilised fuel at remote mine sites after natural gas to generate on-site electricity (BREE 2013c). They are most likely used in remote mines which have no access to natural gas pipelines or are used as a back-up fuel in the case of a natural gas supply failure.

Based on the analysis above, it was assumed that a reasonable estimate for natural gas usage breakdown in the mining sector is 90% for non-grid electricity generation and 10% for heating purposes. Non-grid electricity generation is assumed to have the larger share of natural gas consumption because natural gas is readily available as an energy source for isolated mines far inland with no access to grid electricity and are located close to gas pipelines (see Chapter 4.4.2 for discussion on non-grid electricity generation for mining). Furthermore, natural gas used in LNG manufacturing was assumed to contribute to the consumption of natural gas in the mining sector to provide electricity for LNG liquefaction processes (2012b, Cronshaw et al. 2013).

4.4.2. NON-GRID ELECTRICITY GENERATION

Electricity generation that fell under the category 'principal generation' in Electricity Gas Australia 2010 (Cole & Priftakis 2010) was reported by BREE (Cuevas-Cubria et al. 2011) under Australian thermal electricity generation capacity. Electricity Gas Australia 2010 (Cole & Priftakis 2010) also reported a separate category for 'embedded and non-grid generation' which included all generation outside the SWIS, market participating generation within the SWIS with a capacity less than 10 MW and all non-market participating generation. Electricity generation for isolated communities and mining companies falls under this category. Using this information, the natural gas used in mining for electricity generation can be estimated.

In 2012, 15,812 GWh of electricity was generated off the grid in Australia (BREE 2013c). Off-grid electricity refers to electricity generated and consumed outside of the two major electricity markets in Australia, which are the NEM and the SWIS. 12,202 GWh (77 percent) was consumed in the resources and energy sector and 3,365 GWh by the residential, commercial and community consumers (BREE 2013c). Table 4.49 summarises the BREE statistics for natural gas consumption in the mining sector and off-gird electricity generation. Natural gas dominated the fuel mix of off-grid electricity generation in Australia, accounting for 79 percent of the total off-grid generation in 2012 (12,312 GWh) with a usage of 156.8 PJ (BREE 2013c). This reflects the high proportion of resources and energy operations located in remote areas supplied by natural gas pipelines, such as the Pilbara and Mt. Isa regions. It can be seen in Table 4.49 that Western Australia has both the highest consumption of natural gas in the mining sector and the highest natural gas consumption in off-grid electricity generation, indicating that there is a correlation between natural gas usage in mining and off-grid electricity generation. It was also observed that coal is not used at all in off-grid electricity generation.

Table 4.49: Natural gas statistics for the mining sector and off-grid electricity generation in Australia

State	NSW	VIC	QLD	WA	SA	TAS	NT	AUS
Natural gas consumed in mining sector (BREE 2013a)	0.1	27.6	16.9	184.2	16.8	0.1	16.7	262.4
Natural gas consumption in off-grid electricity generation (BREE 2013c)	-	-	24.9 (Mt Isa) 8.8 (non-Mt Isa)	31.4 (NWIS) 67.4 (non-NWIS)	2.4	-	17.1 (DKIS) 7.2 (non-DKIS)	156.8
% of total off-grid electricity from natural gas (BREE 2013c)	-	-	98.6% (Mt Isa) 67.6% (non-Mt Isa)	98.3% (NWIS) 76.4% (non-NWIS)	97%	-	96.7% (DKIS) 29.7% (non-DKIS)	79%
% of total off-grid electricity consumed in energy and resources sector (BREE 2013c)	-	-	90% (Mt Isa) 79% (non-Mt Isa)	80% (NWIS) 91% (non-NWIS)	82%	-	7% (DKIS) 65% (non-DKIS)	77%

The Pilbara is Western Australia's principle mining region, producing 48.7% of the State's mineral production (Horizon Power 2011a). The North West Interconnected System (NWIS) is an electrically interconnected grid in the Pilbara region that was first formed when iron ore mining companies such as Rio Tinto installed generation and transmission systems to provide electricity for their own mining operations. Horizon Power (2011b) provided descriptions of the current five stakeholders in the NWIS responsible for generating, distributing and selling energy supplies in the North West region:

- Rio Tinto (formerly Robe River and Hamersley Iron) owns the Dampier power station and the part of the NWIS that extends from Dampier to Tom Price, Paraburdoo and Yandi. It also has a power station at Cape Lambert and the part of the NWIS that extends from Cape Lambert to Wickham and Pannawonica.
- Horizon Power is the regional electricity utility owned by the Government of Western Australia which operates the islanded systems and its assets which form, 25 percent of the NWIS. Horizon Power oversees the operation of the NWIS 24 hours a day from a control centre in Karratha. Horizon Power retails power generated by Rio Tinto, Pilbara Iron, Alinta, and other entities to residents and businesses in the population centres of the region.
- BHP Billiton owns the transmission lines connecting to its Finucane Island facility from Wedgefield and that connecting to its Yarrie/Nimingarra operations from Goldsworthy. BHP Billiton purchases its power requirements from Alinta.
- Alinta Energy is the sole supplier of power to BHP Billiton and owns the Port Hedland power station and the Boodarie power station.
- ATCO Australia owns and operates the Karratha power station with all electrical output sold through a long term contract to Horizon Power.

Horizon Power’s supply area includes Port Hedland, Dampier and Karratha and power is supplied to the mining sector, with a portion of Horizon Power’s supplied load on the NWIS consumed by the general community. In addition, several townships including Newman, Tom Price, Paraburdoo and Pannawonica receive their power directly by the relevant mining company. In the NWIS Pilbara region, approximately 20% of electricity consumed was attributed to general community demand, while the remaining 80% was used to supply mining related demand. A total of 31.447 PJ of natural gas was consumed in the NWIS in 2012, which accounts for more than 98 per cent of total generation in the region (BREE 2013c).

Outside the NWIS Pilbara region, the Western Australian off-grid electricity usage is dominated by the resources and energy sector, which account for more than 90% of electricity consumption in the region. 67.433 PJ of natural gas was consumed in 2012 to generate electricity and accounted for more than 76 per cent of total electricity generated in the region, with 20 per cent of total electricity generated was attributed to liquid fuels and the remainder to renewables.

Appendix A.30 summarises the off-grid electricity generators in Western Australia and their respective demand sectors. It can be observed that a large number of natural gas power stations are located at mining sites to provide power specifically for mining purposes. Major mining users of the off-grid electricity include iron ore mines, gold mines, copper mines, nickel mines and natural gas processing plants.

4.4.2.1. NATURAL GAS IN OFF-GRID ELECTRICITY GENERATION

In the mining sector, natural gas is either used in OCGT systems or in reciprocating engines to generate off-grid electricity generation. OCGT systems are often configured to produce sufficient electricity to meet the power demand of nearby mines and provide electricity to nearby residential centres. In the 2010 Electricity Gas Australia publication (Cole & Priftakis 2010), more than 60% of non-principal generation was reported to be generated from OCGT technology. However, this study believes it to be more accurate to model all natural gas consumption in non-grid electricity generation as originating from gas-fired engines. This is to represent the isolated nature of mining centres where each mine relies on its own gas engine to produce power for the mines, thus separating them from residential centres.

4.4.2.1.1. Material flow data

The efficiency of gas engines was assumed to be higher than that for OCGT systems used for peaking grid electricity generation, which is 39%. This was the efficiency chosen for the alternative diesel system (see Chapter 4.4.2.2.1). However, in the case of non-grid electricity generation, the gas engines run at close to baseload electricity generation operating times, thus the capacity utilisation of gas engines was assumed to be 85% instead of 10% used for OCGT peaking power systems. The emission factors for natural gas and fuel oil combustion in turbines from Section 4.3.3.2.1, as well as automotive fuel combustion, are then used to calculate the material flows for natural gas usage in the mining sector, which is given in Table 4.50.

Table 4.50: Final material flow data for the generation of 1 net MWh of non-grid electricity from a 39% efficiency gas-fired engine

Inventory data	Units	Value	Category
Input			
Natural gas	t/MWh	1.80E-01	Feedstock
Output			
CO_2	t/MWh	5.56E-01	Global Warming Potential
CH_4	t/MWh	7.95E-05	Global Warming Potential
N_2O	t/MWh	5.38E-06	Global Warming Potential
VOC	t/MWh	4.70E-04	Photochemical Oxidation Potential
CO	t/MWh	1.26E-03	Photochemical Oxidation Potential
NO_x	t/MWh	1.62E-03	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/MWh	3.08E-06	Acidification Potential
PM_{10}	t/MWh	3.06E-07	Particulate Matter Formation

4.4.2.1.2. Capital costs

The capital cost of a gas-fired engine was based on the capital cost of a diesel-fired engine, which was previously covered in Chapter 4.3.5.2 for diesel-fired peaking power stations. Using Equation 4.16, a capital cost of \$3.1 million was calculated for a 10 MW diesel-fired engine. This capital cost is then adjusted for a gas-fired engine based on a "natural gas versus diesel" study by EPRI (2003). In this study, the diesel project was reported to be \$333/kW while the natural gas project was reported to be \$482/kW. Using Equation 4.17, a 10 MW gas-fired engine was estimated to be \$4.5 million. The natural gas project is more expensive than the diesel project because the natural gas project requires additional accessories installed on the engine to accommodate the gaseous fuel source and additional site development costs to bring natural gas to the site (EPRI 2003).

$$\text{Capital cost of gas engine} = \text{Capital cost of diesel engine} \times \left(\frac{482}{333}\right) \qquad (\text{Equation 4.17})$$

4.4.2.1.3. Operating costs

The operating cost of a 10 MW gas-fired engine was calculated using the operating cost model. As the gas-fired engine units for mining are assumed to be of smaller capacities, fewer operators are required. It was assumed that the annual wage was equivalent to an employee working in the metal ore mining industry. An estimated two process operators are required for the gas engine and control room, each with an estimated annual wage of 2012A\$119,000 for workers in the oil and gas industry (ABS 2013b).

Below are the cash operating cost models for shows the cash operating cost for the generation of electricity from a 39% efficiency gas-fired engine fuelled by natural gas (Table 4.51) and CSG (Table 4.52).

Table 4.51: Cash operating cost for a 39% efficiency gas-fired engine using natural gas (Costs are expressed in 2012A$)

Plant capacity	10	MW
Plant availability	85%	
Annual actual production	74	GWh/yr
Fixed capital investment	4.48	$ million
Capital exponent,ψ (I=αQψ)	0.7	
Cost year	2012	AUD$

Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Natural gas fuel	t	0.180	179	2.39	32.12
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	t	-	0.0770	-	-
Demineralised water	t	-	1.50	-	-
Total variable costs				**2.39**	**32.12**
Operating labour		No.	Salary ($/yr)		
Operators/shift		2			
Shift teams		5			
Total shift operators		10	119,000	1.19	15.98
Total operating labour costs				**1.19**	**15.98**
Payroll overheads		40	% total operating labour cost	0.48	6.39
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.25	3.36
Maintenance labour		1		0.04	0.60
Maintenance materials		1		0.04	0.60
Consumables store			10	0.17	2.24
Plant overheads			100	1.67	22.37
Laboratory			10	0.17	2.24
Insurance		1		0.04	0.60
Property taxes		1		0.04	0.60
Total fixed costs				**4.09**	**54.99**
Total manufacturing costs				**6.49**	**87.11**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	0.29	**3.91**
Marketing costs		5	Total production cost	0.36	**4.89**
Research and development costs		2	Total production cost	0.15	**1.96**
General expenses				**0.80**	**10.77**
Total product cost				**7.29**	**97.87**

Table 4.52: Cash operating cost for a 39% efficiency gas-fired engine using CSG (Costs are expressed in 2012A$)

Plant capacity	10 MW				
Plant availability	85%				
Annual actual production	74 GWh/yr				
Fixed capital investment	4.48 $ million				
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012 AUD$				
Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Coal seam gas fuel	t	0.180	138	1.85	24.85
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	m3		0.0770	-	-
Demineralised water	t		1.50	-	-
Total variable costs				**1.85**	**24.85**
Operating labour		No.	Salary ($/yr)		
Operators/shift		2			
Shift teams		5			
Total shift operators		10	119,000	1.19	15.98
Total operating labour costs				**1.19**	**15.98**
Payroll overheads		40	% total operating labour cost	0.48	6.39
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.25	3.36
Maintenance labour		1		0.04	0.60
Maintenance materials		1		0.04	0.60
Consumables store			10	0.17	2.24
Plant overheads			100	1.67	22.37
Laboratory			10	0.17	2.24
Insurance		1		0.04	0.60
Property taxes		1		0.04	0.60
Total fixed costs				**4.09**	**54.99**
Total manufacturing costs				**5.94**	**79.83**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	0.27	**3.59**
Marketing costs		5	Total production cost	0.33	**4.48**
Research and development costs		2	Total production cost	0.13	**1.79**
General expenses				**0.73**	**9.87**
Total product cost				**6.68**	**89.70**

4.4.2.2. DIESEL OFF-GRID ELECTRICITY GENERATION

4.4.2.2.1. Material flow data

For engines running on liquid fuel, BREE (2013c) reported the average thermal efficiency of off-grid generation from liquid fuels in engines to be 39%.

The material flows of diesel-fired engine power stations with an efficiency of 39% are calculated using the greenhouse gas emission factors for fuel oil from Table A.37 and factors for other emissions to air from stationary large diesel engines in Table A.50 from Appendix A.23.

The final material flow data is shown in Table 4.53.

Table 4.53: Final material flow data for the generation of 1 net MWh of electricity from a 39% effieciency diesel-fired engine for the mining sector

Inventory data	Units	Value	Category
Input			
Diesel	t/MWh	2.09E-01	Fuel
Output			
CO_2	t/MWh	6.73E-01	Global Warming Potential
CH_4	t/MWh	1.32E-05	Global Warming Potential
N_2O	t/MWh	5.96E-06	Global Warming Potential
VOC	t/MWh	3.84E-04	Photochemical Oxidation Potential
CO	t/MWh	3.34E-05	Photochemical Oxidation Potential
NO_x	t/MWh	7.90E-03	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/MWh	1.23E-05	Acidification Potential
PM_{10}	t/MWh	4.26E-04	Particulate Matter Formation

4.4.2.2.2. Capital costs

The capital cost of a diesel-fired engine, which was previously covered in Chapter 4.3.5.2, was calculated using Equation 4.16 for a capacity of 10 MW. The capital cost was calculated to be $3.1 million.

4.4.2.2.3. Operating costs

The operating cost model in Table 4.54 was applied to a 39% efficiency diesel generator. An estimated three process operators are required for the diesel engine, control room and liquids handling.

Table 4.54: Cash operating costs model for a 39% efficiency diesel generator (Costs are expressed in 2012A$)

Plant capacity	10 MW				
Plant availability	85%				
Annual actual production	74 GWh/yr				
Fixed capital investment	3.09 $ million				
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012 AUD$				
Operating costs				**Annual cost ($ million)**	**Cost per unit product ($/MWh)**
Raw materials		Unit usage (/MWh)	Unit cost ($/unit)		
Diesel fuel	t	0.209	888	13.85	186.01
Utilities		Unit usage (/MWh)	Unit cost ($/unit)		
Cooling water	m3		0.0770	-	-
Demineralised water	t		1.50	-	-
Total variable costs				**13.85**	**186.01**
Operating labour		No.	Salary ($/yr)		
Operators/shift		3			
Shift teams		5			
Total shift operators		15	119,000	1.79	23.97
Total operating labour costs				**1.79**	**23.97**
Payroll overheads		40	% total operating labour cost	0.71	9.59
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.37	5.03
Maintenance labour		1		0.03	0.42
Maintenance materials		1		0.03	0.42
Consumables store			10	0.25	3.36
Plant overheads			100	2.50	33.56
Laboratory			10	0.25	3.36
Insurance		1		0.03	0.42
Property taxes		1		0.03	0.42
Total fixed costs				**6.00**	**80.53**
Total manufacturing costs				**19.85**	**266.54**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	0.89	**11.98**
Distributing and marketing costs		5	Total production cost	1.11	**14.97**
Research and development costs		2	Total production cost	0.45	**5.99**
General expenses				**2.45**	**32.94**
Total product cost				**22.30**	**299.49**

4.4.3. HEATING

Apart from generating power, a small amount of natural gas is also used for heating purposes in the mining sector. However, these heating purposes could not be pinpointed easily from commercially available data. These heating applications can be space heating and hot water generation for buildings and accommodations. Another possible application is in the preliminary smelting of gold or extraction of gold from liquor, which is included in the mining category. Activities such as gold ore roasting, which frees up the gold from sulphide ores by converting them into oxides, or bullion production in a crucible furnace will require natural gas fuel. DSEWPC (2006) identified the possible areas where natural gas is used as a fuel: in the roaster as a start-up fuel (after which the exothermic reaction of the sulphide ore provides enough heat for the combustion to continue), as fuel for carbon regeneration and as fuel for the elution, electrowinning and smelting (which can also be powered by electricity)(see Figure 4.23).

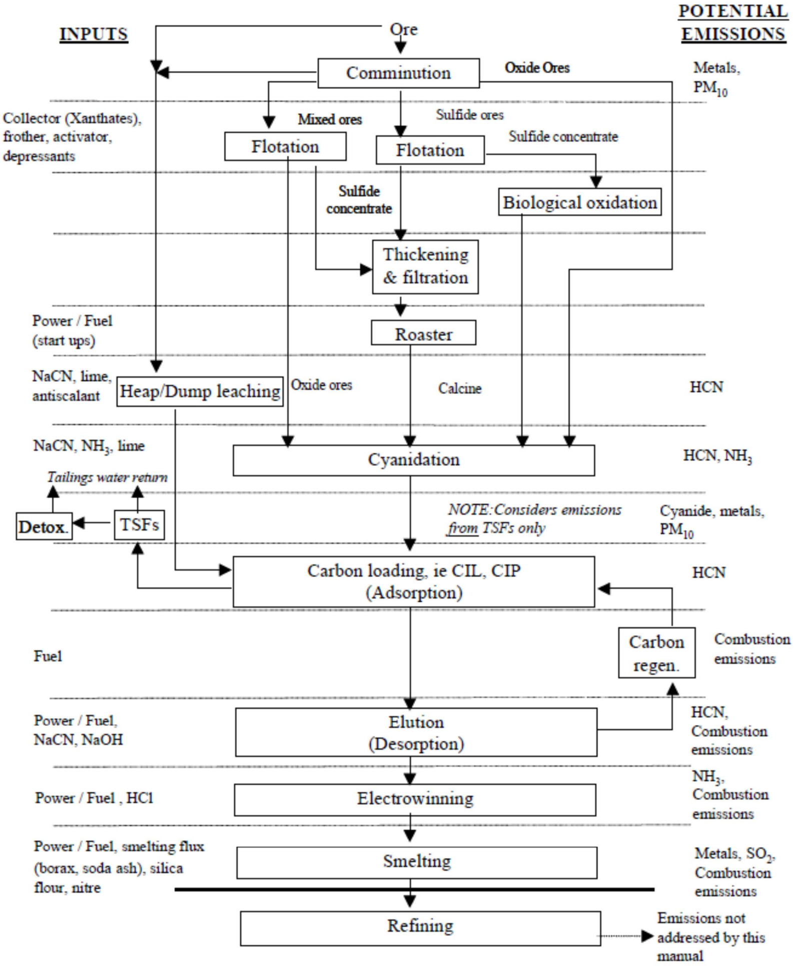


Figure 4.23: Gold ore processing inputs and emissions (DSEWPC 2006)

For this analysis, a fired heater or boiler is chosen as the primary equipment to represent heating application in mining, whether for heating or direct combustion. When the steam cycle equipment is removed, it will resemble a furnace where fuel is combusted for heat. Typical sizes for boilers in the mining industry can range from 100 kW to 50,000 kW depending on the application. For example, boilers with capacities of 160 kW and 1000 kW have been sold by Simons Boiler Co. to gold mines in Western Australia and Papua New Guinea (Simons Boiler Co. 2014).

Two types of boilers are examined in this study: a gas-fired boiler and a diesel-fired boiler that acts as a replacement during a natural gas scarcity. The baseline size for the boiler was chosen to be 10 MW. The efficiency of gas-fired boilers is assumed to be 85% while those running on liquid fuels will have efficiencies of 80%. Boilers usually have high availability or capacity factors, hence a capacity factor 85% was assumed for boilers in this study.

4.4.3.1. MATERIAL FLOWS

Fuel usage for the natural gas-fired boiler and the diesel-fired boiler were calculated using the HHV and the efficiencies for each boiler fuel type. This is shown in Table 4.55. Approximately 0.0229 t of natural gas or CSG and 0.0283 t diesel was required to produce 1 GJ heat respectively.

Table 4.55: Fuel usage calculations for natural gas-fired and diesel-fired boilers

Boiler fuel	HHV (GJ/t)	Efficiency	Fuel required (100% efficiency) (t/GJ_{heat})	Actual fuel required (t/GJ_{heat})
Natural gas	51.3	85%	0.0195	0.0229
Diesel	44.1	80%	0.0227	0.0283

DSEWPC (2011) provided emission factors which are used to estimate emissions to air (excluding greenhouse gas emissions from combustion in boilers. The emission factors are reported in units of t/t fuel, so these are adjusted to units of t/GJ heat by multiplying each mission factor with the fuel usage calculated in Table 4.55.

The greenhouse gas emissions for natural gas and CSG combustion in boilers are calculated using the emission factors from Table A.35 while the other emissions to air from gas-fired boilers are calculated using the emission factors from Table A.48, which are for wall fired boilers with capacity outputs of 30MW and below. Both are located in Appendix A.23.

The final material data for gas-fired boilers are given in Table 4.56.

Table 4.56: Final material flow data for the generation of 1 net GJ of heating from a 85% efficient gas-fired boiler in the mining sector

Inventory data	Units	Value	Category
Input			
Diesel	t/GJ_{heat}	2.29E-02	Fuel
Output			
CO_2	t/GJ_{heat}	6.02E-02	Global Warming Potential
CH_4	t/GJ_{heat}	5.60E-06	Global Warming Potential
N_2O	t/GJ_{heat}	1.14E-07	Global Warming Potential
VOC	t/GJ_{heat}	2.73E-06	Photochemical Oxidation Potential
CO	t/GJ_{heat}	4.17E-05	Photochemical Oxidation Potential
NO_x	t/GJ_{heat}	1.58E-05	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/GJ_{heat}	5.47E-07	Acidification Potential
PM_{10}	t/GJ_{heat}	3.67E-06	Particulate Matter Formation

For diesel-fired boilers, the greenhouse gas emissions are assumed to be that of fuel oil and are calculated using the emission factors from Table A.37, while the other emissions to air are calculated using the emission factors in Table A.47, which are for wall fired boilers with capacity outputs of 30 MW and below. Both are located in Appendix A.23.

The final material data for diesel-fired boilers are given in Table 4.57.

Table 4.57: Final material flow data for the generation of 1 net GJ of heating from a 80% efficient diesel-fired boiler in the mining sector

Inventory data	**Units**	**Value**	**Category**
Input			
Diesel	t/GJ_{heat}	2.84E-02	Fuel
Output			
CO_2	t/GJ_{heat}	9.11E-02	Global Warming Potential
CH_4	t/GJ_{heat}	1.79E-06	Global Warming Potential
N_2O	t/GJ_{heat}	8.06E-07	Global Warming Potential
VOC	t/GJ_{heat}	7.72E-07	Photochemical Oxidation Potential
CO	t/GJ_{heat}	1.93E-05	Photochemical Oxidation Potential
NO_x	t/GJ_{heat}	7.72E-05	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/GJ_{heat}	5.47E-07	Acidification Potential
PM	t/GJ_{heat}	3.97E-06	Particulate Matter Formation

4.4.3.2. CAPITAL COSTS

The capital cost of a 10 MW gas-fired boiler was estimated to be $300,000. This cost was taken from Appendix A.31 and was adjusted from year 2000 to year 2012 Australian dollars.

For the diesel boiler, the U.S. EPA (1978) reported that modifications to convert an existing gas boiler to oil-firing will have a capital cost of at least 25% of the capital costs of a new boiler. The major cost of a gas to diesel conversion will be the diesel storage and handling costs, which will constitute 75% of the diesel conversion costs. The remaining costs are for the installation of fuel supply lines and diesel burners, as well as modification of boiler internals to account for different flames and different furnace heat release rates. Thus, the capital cost of a diesel-fired boiler is estimated from the capital cost of a gas-fired boiler multiplied by a factor of 1.25. The capital costs for gas- and diesel-fired boilers are summarised in Table 4.58.

Table 4.58: Capital costs for gas- and diesel-fired boilers

Fuel type	Gas	Diesel
Sent-out capacity (MW heating)	10	10
Efficiency (%)	85	80
Boiler capital cost (2012A$mil)	0.432	0.540

4.4.3.3. OPERATING COSTS

The cash operating costs for boilers were obtained using the operating cost model and were calculated for natural gas fuel in Table 4.59, CSG fuel in Table 4.60 and diesel fuel in Table 4.61. An estimated two process operators are required for the boilers and control room for gas-based heating, and an additional operator is required for diesel-base heating for liquids handling.

Table 4.59: Cash operating cost for a 85% efficiency boiler running on natural gas

Plant capacity	10	MW_{heat}			
Plant availability	85%				
Annual actual production	268,000	GJ_{heat}/yr			
Fixed capital investment	0.432	$million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($million)**	**Cost per unit product ($/$GJ_{heat}$)**
Raw materials		Unit usage (/GJ_{heat})	Unit cost ($/unit)		
Natural gas fuel	t	0.0229	179	1.10	4.09
Utilities		Unit usage (/GJ_{heat})	Unit cost ($/unit)		
Cooling water	t	-	0.0770	-	-
Municipal water	t	-	1.50	-	-
Total variable costs				**1.10**	**4.09**
Operating labour		No.	Salary ($/yr)		
Operators/shift		2			
Shift teams		5			
Total shift operators		10	119,000	1.19	4.44
Total operating labour costs				**1.19**	**4.44**
Payroll overheads		40	% total operating labour cost	0.48	1.78
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.25	0.93
Maintenance labour			110	1.83	6.84
Maintenance materials		1		0.004	0.02
Consumables store			10	0.17	0.62
Plant overheads			100	1.67	6.22
Laboratory			0	0.00	0.00
Insurance		1		0.004	0.02
Property taxes		1		0.004	0.02
Total fixed costs				**5.59**	**20.87**
Total manufacturing costs				**6.69**	**24.97**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	0.14	**0.53**
Marketing costs		2	Total production cost	0.14	**0.53**
Research and development costs		1	Total production cost	0.07	**0.26**
General expenses				**0.35**	**1.31**
Total product cost				**7.04**	**26.28**

Table 4.60: Cash operating cost for a 85% efficiency boiler running on CSG

Plant capacity	10	MW_{heat}			
Plant availability	85%				
Annual actual production	268,000	GJ_{heat}/yr			
Fixed capital investment	0.432	$million			
Capital exponent,ψ ($I=\alpha Q\psi$)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($million)**	**Cost per unit product ($/GJ$_{\text{heat}}$)**
Raw materials		Unit usage (/GJ$_{\text{heat}}$)	Unit cost ($/unit)		
Coal seam gas fuel	t	0.0229	138	0.85	3.17
Utilities		Unit usage (/GJ$_{\text{heat}}$)	Unit cost ($/unit)		
Cooling water	t	-	0.0770	-	-
Municipal water	t	-	1.50	-	-
Total variable costs				**0.85**	**3.17**
Operating labour		No.	Salary ($/yr)		
Operators/shift		2			
Shift teams		5			
Total shift operators		10	119,000	1.19	4.44
Total operating labour costs				**1.19**	**4.44**
Payroll overheads		40	% total operating labour cost	0.48	1.78
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.25	0.93
Maintenance labour			110	1.83	6.84
Maintenance materials		1		0.004	0.02
Consumables store			10	0.17	0.62
Plant overheads			100	1.67	6.22
Laboratory			0	0.00	0.00
Insurance		1		0.004	0.02
Property taxes		1		0.004	0.02
Total fixed costs				**5.59**	**20.87**
Total manufacturing costs				**6.44**	**24.04**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	0.14	**0.51**
Marketing costs		2	Total production cost	0.14	**0.51**
Research and development costs		1	Total production cost	0.07	**0.25**
General expenses				**0.34**	**1.27**
Total product cost				**6.78**	**25.31**

Table 4.61: Cash operating costs for a 80% efficiency boiler running on diesel fuel

Plant capacity	10	MW_{heat}			
Plant availability	85%				
Annual actual production	267,768	GJ_{heat}/yr			
Fixed capital investment	0.540	$million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($million)**	**Cost per unit product ($/$\text{GJ}_{heat}$)**
Raw materials		Unit usage (/GJ_{heat})	Unit cost ($/unit)		
Diesel fuel	t	0.0284	888	6.74	25.19
Utilities		Unit usage (/GJ_{heat})	Unit cost ($/unit)		
Cooling water	t	-	0.0770	-	-
Municipal water	t	-	1.50	-	-
Total variable costs				**6.74**	**25.19**
Operating labour		No.	Salary ($/yr)		
Operators/shift		3			
Shift teams		5			
Total shift operators		15	119,000	1.79	6.67
Total operating labour costs				**1.79**	**6.67**
Payroll overheads		40	% total operating labour cost	0.71	2.67
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.37	1.40
Maintenance labour			110	2.75	10.27
Maintenance materials		1		0.005	0.02
Consumables store			10	0.25	0.93
Plant overheads			100	2.50	9.33
Laboratory			0	0.00	0.00
Insurance		1		0.005	0.02
Property taxes		1		0.005	0.02
Total fixed costs				**8.39**	**31.33**
Total manufacturing costs				**15.13**	**56.51**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	0.32	**1.19**
Marketing costs		2	Total production cost	0.32	**1.19**
Research and development costs		1	Total production cost	0.16	**0.59**
General expenses				**0.80**	**2.97**
Total product cost				**15.93**	**59.49**

4.4.4. SUBSTITUTION IMPACTS FOR MINING

In the event of a natural gas scarcity, black coal was not considered as a suitable substitute because of the large number of mines that are isolated from the grid and are far away from rail infrastructure. Assuming these mines use gas-fired engines and boilers, diesel is the next best alternative fuel to substitute natural gas as it can be used in existing engines and boilers after a few modifications. CSG as a substitute for natural gas in off-grid electricity and heating is also considered.

Table 4.62 shows the substitution impact indicators for the mining sector. Substitution of natural gas with diesel will cause an increase in all categories in both off-grid electricity generation and heating, except for freshwater withdrawal. The results are similar to the substitution of natural gas with diesel peaking grid electricity generation. This is due to the relatively large water consumption in the natural gas upstream section compared to diesel, and may be attributed to large evaporation rates in the natural gas purification plants. The GWP reported for substitution of natural gas with diesel in heating was higher than that for off-grid electricity generation because of the drop in efficiency when modifying the gas-fired boiler into a diesel-fired boiler. As for substitution with CSG, the impacts were reported to be identical to that in the grid electricity generation, and for all the other sectors as well. The reason for the similar results and for the increases in associated water withdrawal and solid waste generation were previously explained in the grid electricity generation section.

The capital cost indicator shows the capital cost and operating cost penalties for off-gird electricity generation is higher than heating when natural gas is substituted for diesel. Due to the assumption that 90% of natural gas usage in mining is attributed to electricity generation and the low cost of boilers, the impacts of substitution in heating are as significant as that from off-grid electricity generation. Calculations to obtain the substitution impact indicators for the mining sector are located in Appendix A.32.

Table 4.62: Substitution impact indicators for natural gas substitution in the Australian mining sector

Option	Off-grid electricity		Heating	
Feedstock	NG→D	NG→CSG	NG→D	NG→CSG
Technology	IC	IC	Boiler	Boiler
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	+ 1.32E-09	- 1.14E-10	+ 2.62E-09	- 1.14E-10
Acidification Potential (ADP)	+ 1.47E-08	- 3.55E-10	+ 1.53E-09	- 3.55E-10
Photochemical Oxidation Potential (POP)	+ 1.02E-08	- 3.93E-09	+ 4.86E-10	- 3.93E-09
Particulate Matter Formation (PMF)	+ 2.99E-09	- 9.29E-11	+ 1.54E-10	- 9.29E-11
Freshwater Withdrawal (FWW)	- 1.23E-12	- 3.50E-12	- 1.23E-12	- 3.50E-12
Associated Water Withdrawal (AWW)	+ 4.31E-10	+ 1.44E-08	+ 4.31E-10	+ 1.44E-08
Saline Water Generation (CWG)	+ 5.02E-15	- 7.17E-13	+ 5.02E-15	- 7.17E-13
Solid Waste Generation (SWG)	+ 3.76E-11	+ 6.95E-10	+ 3.76E-11	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+24.5	-	+1.1	-
Cash operating costs	+ 1,120.0	- 45.5	+ 161.0	- 4.73
Total operating costs	+ 1,150.0	- 45.5	+ 162.0	- 4.73

Legend: '+' sign denotes increase in impacts, '-' sign denotes decrease in impacts, NG=Natural Gas, D=Diesel, CSG=Coal Seam Gas, IC=Internal Combustion

Note: Environmental impact indicators include upstream and downstream impacts.

4.5. CHEMICALS

4.5.1. OVERVIEW

In the Australian chemicals sector, natural gas is used both as a fuel and a feedstock. Figure 4.24 shows the various chemical manufacturing pathways in Australia originating from natural gas. Hydrogen was seen to be the precursor of ammonia, which is itself an intermediate in the production of chemicals such as urea, ammonium nitrate, sodium cyanide.

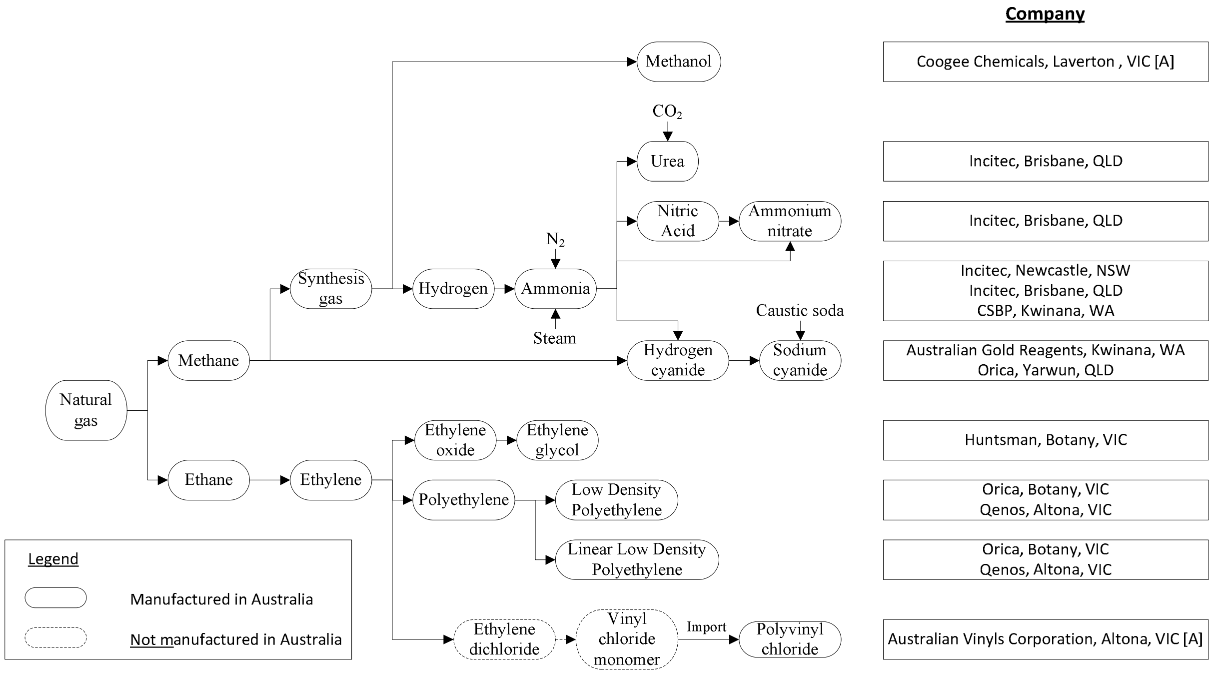


Figure 4.24: Major chemical manufacturing pathways from natural gas in Australia (Chemlink n.d.)

Hydrogen's current main use is in the chemicals industry. Figure 4.25 shows the hydrogen usage breakdowns in Germany, U.S., U.K. and worldwide. Germany and U.S. hydrogen usages were limited to the chemicals industry in the year 1978 and has changed relatively little then (Häussinger et al. 2012b). Hydrogen is also used as fuel for heating in these two countries, which was reported to be 27.4% of total hydrogen usage for Germany whereas this figure was not known for the U.S. The majority of hydrogen consumption in the U.K. and worldwide was also in the chemicals industry (British Energy 2002, Wawrzinek & Keller 2007). Ammonia synthesis was the single main usage of hydrogen overall, with the exception of the U.S. where it was the second largest after refining operations. There is ongoing research to develop the other uses of hydrogen, such as in the area of fuel cells, which will further increase the need for hydrogen and natural gas, which is a source of hydrogen.

This chapter will examine the environmental and economic impacts of substitution in hydrogen production and explain the method to adapt these values for ammonia production. Ammonia production will then be used to represent the chemical sector in the system-wide analysis.

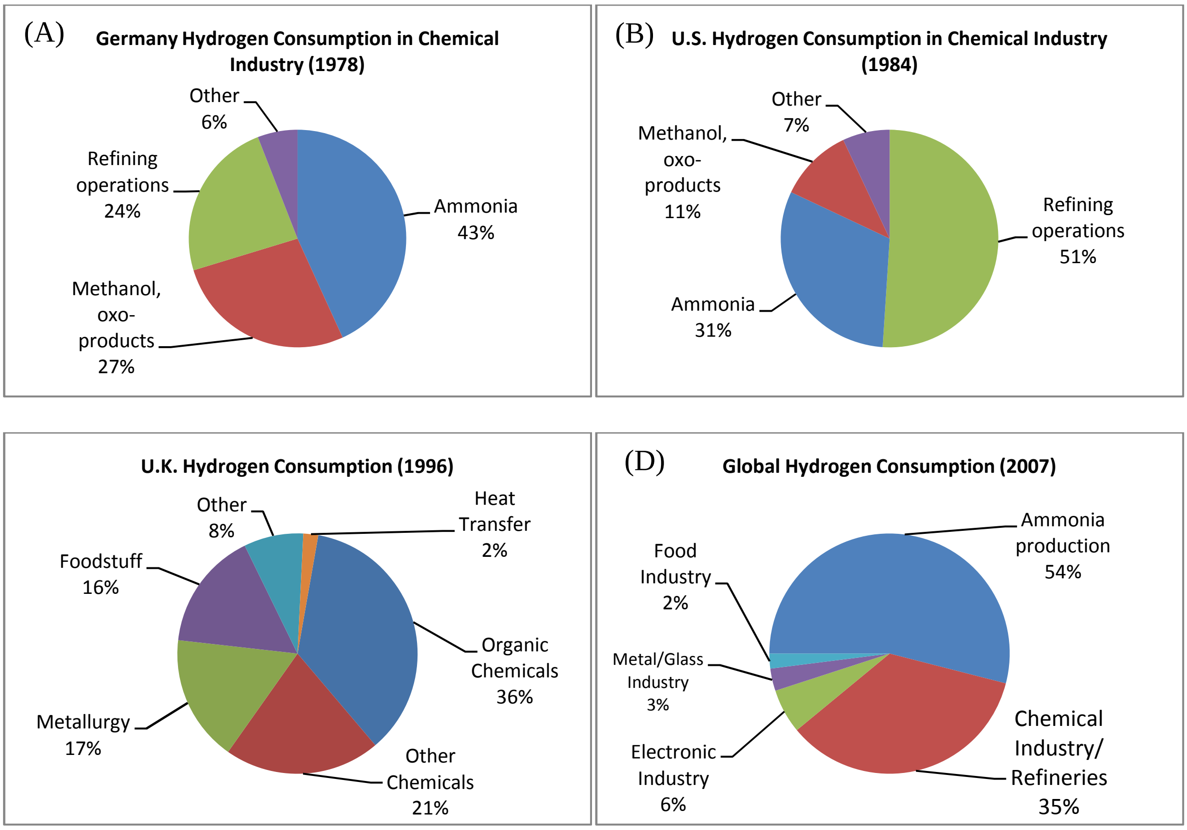


Figure 4.25: Hydrogen consumption patterns for (A) Germany (1978) (B) U.S. (1978) (C) U.K. (1996) (D) Worldwide (2007) (British Energy 2002, Wawrzinek & Keller 2007, Häussinger et al. 2012b)

4.5.2. HYDROGEN

4.5.2.1. INTRODUCTION

Hydrogen can be produced commercially through steam reforming of natural gas, gasification of coal and the partial oxidation of hydrocarbons. Partial oxidation processes can handle a wide range of feedstock ranging from natural gas to fuel oils. Gaseous hydrocarbons can be converted to hydrogen and carbon monoxide by catalytic steam reforming, where the main feedstock is natural gas. Hydrogen can also be produced through electrolysis of water using power from any source, including renewable energy such as solar, wind and hydroelectricity. Figure 4.26 shows the various sources of hydrogen globally, where almost half of the world's hydrogen is produced from natural gas.

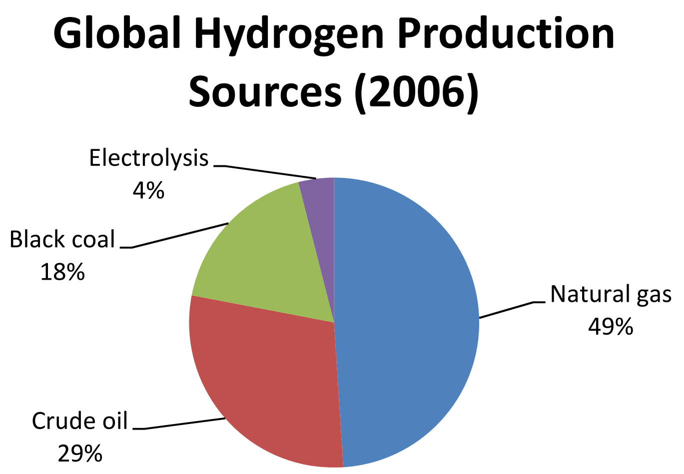


Figure 4.26: Global hydrogen production sources (SRI Consulting 2007)

Hydrogen can be produced and recovered in refinery processes such as cokers, visbreakers, catalytic crackers and catalytic reformers. Hydrogen is also a by-product from the production of ethylene, propene, acetylene, and also from electrochemical processes such as the production of sodium hydroxide, chlorine and chlorine compounds.

Häussinger et al. (2012b) covered the various usages of hydrogen in Ullmann's Encyclopaedia of Industrial Chemistry. Hydrogen takes part in reactions either by addition (hydrogenation) or by means of its reduction potential. In refineries, hydrogen takes part in hydrotreating processes to increase the hydrogen content of heavy crude oil fractions and in hydrocracking processes to produce lighter fractions. Undesired elements such as sulphur, nitrogen and metals can be removed using hydrogen by converting into hydrogen sulphide and ammonia. Hydrogen is used to synthesize chemicals such as methanol, aldehyde, hydrogen peroxide, hydrochloric acid and hydroxylamine. Hydrogen also has many industrial applications, such as in the foods industry for the hydrogenation of fats and oils, in the industrial production of sugar alcohols such as sorbitol, xylitol, and mannitol, as well as in the manufacture of pharmaceuticals, polymers, solvents, plasticizers and detergents. In metallurgy, hydrogen is used to reduce iron ore, and is used as a reducing agent and as a utility in the production and handling of non-ferrous metals such as copper, nickel, cobalt, molybdenum, tungsten, tantalum, germanium and uranium. Hydrogen is also used in small quantities in metals processing, semiconductor technology and water treatment. Hydrogen can also be used as a fuel to produce electricity in a fuel cell or in an internal combustion engine; both applications are gaining increasing attention in the transport and electricity generation sector.

4.5.2.2. STEAM METHANE REFORMING (SMR)

The majority of hydrogen in Australia is produced on a large scale via reforming of natural gas, and the remainder as a by-product from processes such as the production of chlorine, caustic soda and hydrogen production from chlor-alkali plants. Steam methane reforming (SMR) involves natural gas reacting with steam in a highly endothermic reaction to form carbon monoxide and hydrogen. The amount of steam added to the natural gas feedstock is quantified by the molar steam-to-carbon ratio. Common ratios for natural gas operation are 2.5 to 3. The general equation for the SMR process is shown in Equation 4.18.

$$C_aH_bO_c + (a-c)H_2O \xrightarrow{heat} aCO + \left(a + \frac{b}{2} - c\right)H_2 \qquad \text{(Equation 4.18)}$$

For natural gas, which is mostly methane, the equation becomes Equation 4.19.

$$CH_4 + H_2O \xrightarrow{heat} CO + 3H_2 \qquad \Delta H^{\circ}_{298} = +206 kJ/mol \qquad \text{(Equation 4.19)}$$

The typical SMR route to produce hydrogen is shown in Figure 4.27 and is modelled after the German Linde design (Häussinger et al. 2012a, Linde 2014). Boyce et al. (2004) and Häussinger et al. (2012b) referred to the design as a ‘modern style’ hydrogen plant, while the ‘old style’ hydrogen plants had high temperature and low temperature shift reactors, a CO_2 removal unit and a methanator instead of a single High Temperature Shift Convertor (HTSC) and a Pressure Swing Adsorption (PSA) unit. The PSA unit produces a hydrogen product of a much higher purity (99.99%) and purifies the syngas effluent from the HTSC, hence not requiring the Low Temperature Shift Convertor (LTSC) to further reduce the CO content. The PSA tail gas can then be used as the primary fuel for the reformer furnace.

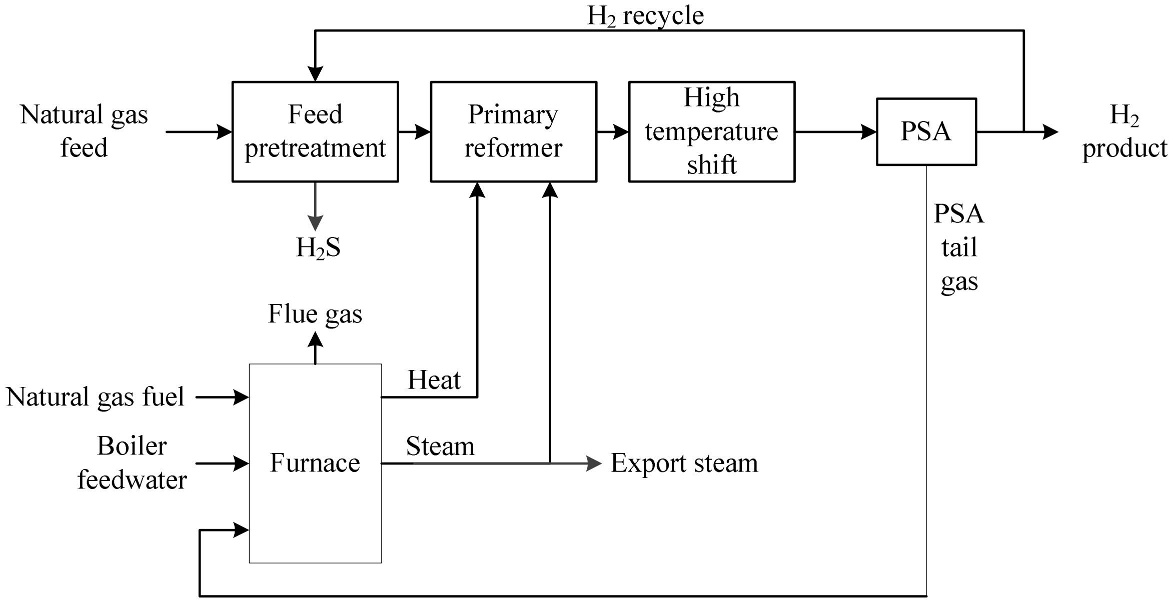


Figure 4.27: Hydrogen production via the SMR route (Häussinger et al. 2012a, Linde 2014)

After hydro-desulphurisation, the feedstock is directed into a fired tubular reactor (primary reformer) where the reaction takes place at 870°C and pressure conditions of around 2 MPa over a nickel reforming catalyst (Häussinger et al. 2012a). The nickel catalysts are particularly sensitive to poisoning by sulphur, as concentrations as low as 0.1 ppm form a deactivating layer on the catalyst. The reformer product gas is cooled and fed into a HTSC, where carbon monoxide reacts with excess water to form additional hydrogen in Equation 4.20.

$$CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \Delta H^{\circ}_{298} = -41 kJ/mol \qquad \text{(Equation 4.20)}$$

After the HTSC, the gas is cooled to ambient temperature and water is condensed and removed. Hydrogen is separated from CO_2 using PSA and the CO_2 stream is fired in the reformer furnace along with a small amount of fuel gas. The heat from the furnace supplies heat for the overall endothermic reaction, as well as for feed preheating, steam generation for reforming, and excess steam.

4.5.2.2.1. Material flows

The SMR plant is modelled using emission to air factors for boilers as reported in Table A.48 in Appendix A.23, together with greenhouse gas emission factors for natural gas combustion as reported by DCCEE (2011). This is summarised in Table 4.63. In addition, the SMR reaction which converts natural gas feedstock into hydrogen will also produce a stoichiometric amount of CO_2, which will mix with the CO_2 from the natural gas fuel combustion in the furnace and exit together through the flue stack. 4.8 t/t H_2 of water is required for the reforming and shift reactions. The SMR plant produces excess steam which is then exported. The export steam was adapted from Spath and Mann (2001) and adjusted to produce high pressure steam at 310°C and 10,000 kPa. The adjustment process is detailed in Appendix A.33.

Several hydrogen studies and their reported material flows are included in Appendix A.34. Spath and Mann (2001) provided useful information regarding the material flows for a SMR plant as well as emission data, while the other literature provided at least natural gas and water consumption figures.

Table 4.63: Material flow data for a steam methane reforming hydrogen plant

Inventory data	Units	Hydrogen plant	Electricity material flows [a]	Total	Category
Imput					
Natural gas	t/t H_2	3.17E-01	9.29E-03	3.27E-01	Feedstock
Black coal	t/t H_2	0	1.45E-01	1.45E-01	Feedstock
Cooling water makeup	t/t H_2	5.67	8.12E-01	6.48	Freshwater Withdrawal
Boiler feedwater makeup	t/t H_2	25.3	4.53E-02	25.3	Freshwater Withdrawal
Output					
Export steam	t/t H_2	14.2	0	14.2	Byproduct
Cooling water blowdown	t/t H_2	8.86E-01	8.83E-02	9.74E-01	Saline Water Generation
Steam blowdown	t/t H_2	1.20	4.53E-02	1.25E+00	Saline Water Generation
CO_2	t/t H_2	8.79	3.36E-01	9.13	Global Warming Potential
CH_4	t/t H_2	7.76E-05	7.32E-06	8.49E-05	Global Warming Potential
N_2O	t/t H_2	1.58E-06	2.94E-07	1.87E-06	Global Warming Potential
VOC	t/t H_2	3.78E-05	2.33E-06	4.01E-05	Photochemical Oxidation Potential
CO	t/t H_2	5.78E-04	7.44E-04	1.32E-03	Photochemical Oxidation Potential
NO_x	t/t H_2	6.86E-04	5.02E-05	7.36E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t H_2	7.57E-06	2.28E-07	7.80E-06	Acidification Potential
PM_{10}	t/t H_2	5.08E-05	5.21E-05	1.03E-04	Particulate Matter Formation
Ash	t/t H_2	0	3.07E-02	3.07E-02	Solid Waste Generation

[a] Electricity assumed to be generated from Australian reference grid electricity fuel mix (see Appendix A.20)

4.5.2.2.2. Capital cost

Figure 4.28 shows the cost versus capacity data for SMR hydrogen plants found in the literature. These costs are representative of the bare erected plant costs and exclude components such as costs related to the outside battery limits. The capital cost of steam methane reforming plants can be estimated using Equation 4.21.

$$I = 0.042Q^{0.73} \qquad \text{(Equation 4.21)}$$

where I = Plant capital cost in 2012A$million
Q = Plant production capacity in t/yr

This was represented as a curve of best line plotted through the literature cost data in Figure 4.28. The details of the hydrogen plant capital costs from literature are located in Appendix A.35.

Gary et al. (2007) have provided a cost curve to estimate the investment cost of steam methane reforming plants, which was shown as a dotted line in Figure 4.28. The cost curve was valid only in the production capacity range between 2,600 to 17,600 t/ yr of hydrogen gas product. Hydrogen plants in this production capacity range are typically the size found in the petroleum refining industry and are relatively smaller than the large scale stand-alone hydrogen plants reported in other literature. WYLD group (2008) classifies a hydrogen plant with a production capacity of 1,100 t/yr to be small scale, while a medium scale hydrogen plant produced 9,855 t/yr and a large scale hydrogen plant produced 138,700 t/yr. It can be seen that the curve of best fit in Figure 4.28 lined up well with the cost curve in Gary et al. (2007).

The capital costs for three actual hydrogen plants were also included in Figure 4.28. The details of these hydrogen plants are located in Appendix A.35. When plotted against the cost curve, the U.S. hydrogen plant was located close to the trendline represented by Equation 4.21, while the other two hydrogen plants belonged to Thyssen Krupp Uhde GmbH and had capital costs that were much lower than the average hydrogen plant.

As the majority of hydrogen produced in Australia is currently used in ammonia manufacture, the capital and operating cost of the hydrogen plant used in this analysis needed to represent a large scale stand-alone hydrogen plant. The hydrogen plant capital cost reported by Rutkowski (2012), shown as Point (5) in Figure 4.28, was chosen as it was the closest to the SMR hydrogen plant cost curve. Additionally, the hydrogen plant had a hydrogen production capacity of 379 t/day, which is similar to the reference 380 t/day (138,700 t/yr) steam methane reforming plant reported by WYLD group (2008). The installed plant capital cost was reported to be $135 million in 2005 U.S. dollars ($227 million in 2012 Australian dollars) for a 380 t/day H_2 plant. Taking into account engineering and construction management (assumed to be 25% of direct capital cost), the total capital cost of the SMR plant was found to be $284 million in 2012 Australian dollars.

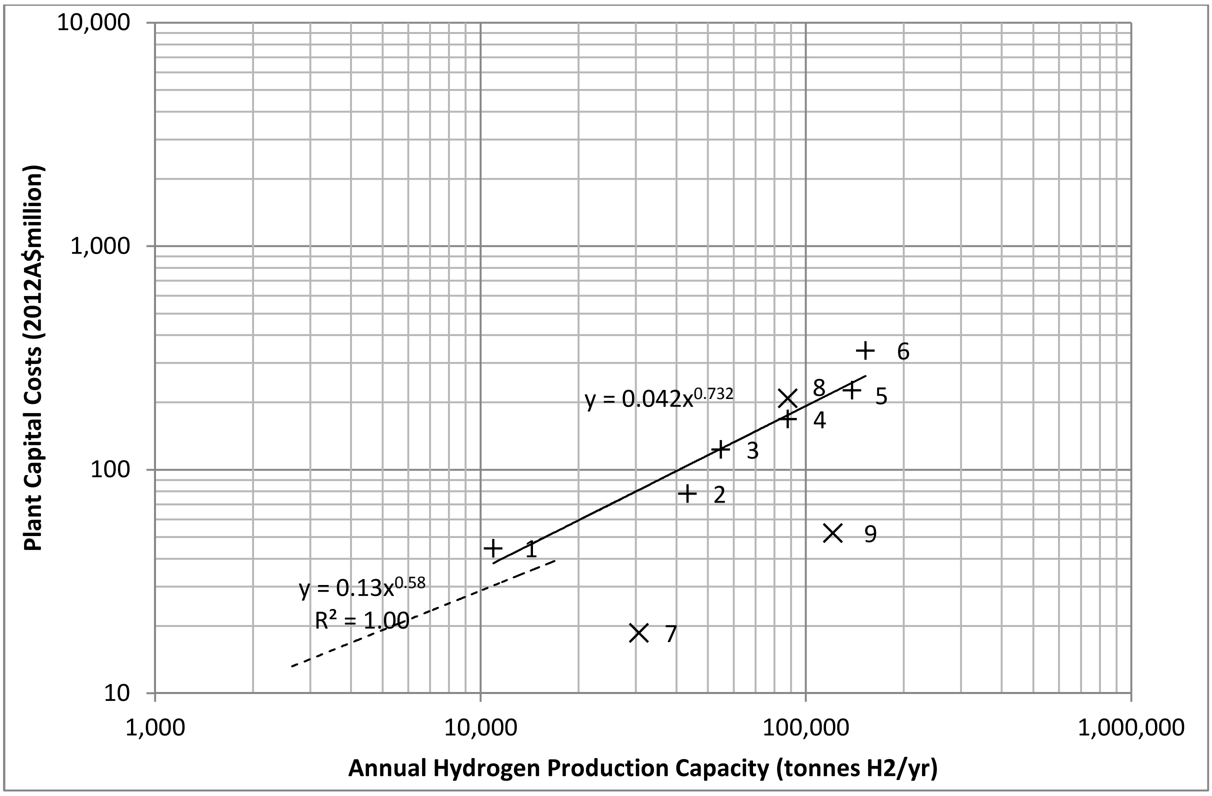


Figure 4.28: Steam reforming hydrogen plant costs in 2012 Australian dollars against production capacity in t H_2/yr.

Note: The dotted line shows the capital investment cost curve of steam methane reforming plants found in Gary et al. (2007). The literature plant costs shown are (1) Sinclair (1996), (2) Molburg & Doctor (2003), (3) Simbeck & Chang (2002), (d) Gray & Tomlinson (2001), (5) Rutkowski (2012) and (6) Klett et al. (2002). The solid line shows the curve of best fit between plants 1-6. The actual plant costs shown are (7) Koch-Glitsch (Uhde) (8) Carson (Air Products and Chemicals) (9) Neste Oil Porvoo Refinery (Uhde)

4.5.2.2.3. Operating cost

Table 4.64 and Table 4.65 show the operating cost models for the natural gas and CSG case respectively without export steam revenue. Costs are expressed in 2012 Australian dollars.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the steam reforming process, there are three process zones, which are the pre-treatment, reformer and furnace as one zone, and the shift and PSA as one zone. An additional operator is required for the control room. Hence, four process operators are required. Rutkowski (2012) provided information regarding the costs of catalysts and sorbents, which were \$2.1 million/yr or approximately \$18/t H_2. For this analysis, an equal amount of \$18/t H_2 was allocated for catalysts and sorbents.

Table 4.64: Operating cost model for baseline steam methane reforming plant using natural gas (Costs are expressed in 2012A$)

Plant capacity	380 t/day				
Plant availability	85%				
Annual actual production	118,000 t/yr				
Fixed capital investment	284 $ million				
Capital exponent,ψ (I=αQψ)	0.732				
Cost year	2012 AUD$				
Operating costs				**Annual cost ($ million)**	**Cost per tonne H_2 ($/t H_2)**
Raw materials		Unit usage (/t H_2)	Unit cost ($/unit)		
Natural gas fuel/feedstock	t	3.21	179	67.68	573.56
Utilities		Unit usage (/t H_2)	Unit cost ($/unit)		
Electricity	MWh	0.569	70.0	4.70	39.83
Cooling water	m3	295	0.0770	2.68	22.73
Demineralised water	t	25.30	1.50	4.48	37.96
Catalysts and sorbents				2.12	18.00
Total variable costs				**81.66**	**692.07**
Byproducts		Unit usage (/t H_2)	Unit cost ($/unit)		
Byproduct steam	t	14.2	25.5	-42.75	-362.33
Total byproduct costs				**-42.75**	**-362.33**
Operating labour		No.	Salary ($/yr)		8
Operators/shift		4			
Shift teams		5			
Total shift operators		20	87,000	1.74	14.75
Total operating labour costs				**1.74**	**14.75**
Payroll overheads		40	% total operating labour cost	0.70	5.90
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.37	3.10
Maintenance labour		1		2.84	24.06
Maintenance materials		1		2.84	24.06
Consumables store			10	0.24	2.06
Plant overheads			100	2.44	20.64
Laboratory			10	0.24	2.06
Insurance		1		2.84	24.06
Property taxes		1		2.84	24.06
Total fixed costs				**17.08**	**144.75**
Total manufacturing costs				**55.99**	**474.50**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	2.60	22.07
Marketing costs		5	Total production cost	3.26	27.59
Research and development costs		5	Total production cost	3.26	27.59
General expenses				**9.11**	**77.24**
Total product cost				**65.11**	**551.74**

Table 4.65: Operating cost model for baseline steam methane reforming plant using CSG (Costs are expressed in 2012A$)

Plant capacity	380	t/day			
Plant availability	85%				
Annual actual production	118,000	t/yr			
Fixed capital investment	284	$ million			
Capital exponent,ψ (I=αQψ)	0.732				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per tonne H_2 ($/t H_2)**
Raw materials		Unit usage (/t H_2)	Unit cost ($/unit)		
Coal seam gas fuel/feedstock	t	3.21	138	52.36	443.71
Utilities		Unit usage (/t H_2)	Unit cost ($/unit)		
Electricity	MWh	0.569	70.0	4.70	39.83
Cooling water	m3	295	0.0770	2.68	22.73
Demineralised water	t	25.30	1.50	4.48	37.96
Catalysts and sorbents				2.12	18.00
Total variable costs				**66.34**	**562.22**
Byproducts		Unit usage (/t H_2)	Unit cost ($/unit)		
Byproduct steam	t	14.2	25.5	-42.75	-362.33
Total byproduct costs				**-42.75**	**-362.33**
Operating labour		No.	Salary ($/yr)		
Operators/shift		4			
Shift teams		5			
Total shift operators		20	87,000	1.74	14.75
Total operating labour costs				**1.74**	**14.75**
Payroll overheads		40	% total operating labour cost	0.70	5.90
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.37	3.10
Maintenance labour		1		2.84	24.06
Maintenance materials		1		2.84	24.06
Consumables store			10	0.24	2.06
Plant overheads			100	2.44	20.64
Laboratory			10	0.24	2.06
Insurance		1		2.84	24.06
Property taxes		1		2.84	24.06
Total fixed costs				**17.08**	**144.75**
Total manufacturing costs				**40.67**	**344.65**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	1.89	16.03
Marketing costs		5	Total production cost	2.36	20.04
Research and development costs		5	Total production cost	2.36	20.04
General expenses				**6.62**	**56.11**
Total product cost				**47.29**	**400.75**

The total operating cost for hydrogen production from natural gas and CSG are summarised in Table 4.66. Costs were reported per t H_2 and per GJ H_2.

Table 4.66: Total operating costs for the baseline SMR hydrogen plants using natural gas (NG) and CSG feedstock (Costs are expressed in 2012A$)

Capacity (t/day)		380			
Output (t/year)		117,895			
Annualised capital costs (A$/t H_2)		255			
Export steam revenue @ $25.5/t		Excluded		Included	
Feedstock type		NG	CSG	NG	CSG
Cash operating costs	Variable costs (A$/t H_2)	692	562	692	562
	Fixed costs (A$/t H_2)	145	145	145	145
	Other costs (A$/t H_2)	136	115	77.2	56.1
	Total (A$/t H_2)	973	822	552	401
Total operating costs (A$/t H_2)		1,230	1,080	807	656
Total operating costs (A$/GJ H_2)		8.64	7.58	5.68	4.62

4.5.2.3. COAL GASIFICATION

Gasification can be used with a variety of feedstocks including refinery wastes, biomass and municipal solid waste. According to Häussinger et al. (2012a), the highest yield is achieved if the pulverised coal is gasified with oxygen at high temperatures. This is done in the entrained-bed gasification reactor, which is commercialised in the Koppers-Totzek and the Texaco process. The overall reactions involving partial oxidation and gasification in steam will follow Equation 4.22 and Equation 4.23.

$$C_aH_b + \frac{a}{2}O_2 \leftrightarrow aCO + \frac{b}{2}H_2 \qquad \text{(Equation 4.22)}$$

$$C_aH_b + aH_2O \leftrightarrow aCO + \left(a + \frac{b}{2}\right)H_2 \qquad \text{(Equation 4.23)}$$

Dufour et al. (2011) outlined the complexity of the gasification of coal with steam with the following reaction pathways:

$$C + O_2 \rightarrow CO_2 \qquad \Delta H^\circ_{298} = -406 kJ/mol \qquad \text{(Equation 4.24)}$$

$$C + \frac{1}{2}O_2 \rightarrow CO \qquad \Delta H^\circ_{298} = -123 kJ/mol \qquad \text{(Equation 4.25)}$$

$$C + CO_2 \leftrightarrow 2CO \qquad \Delta H^\circ_{298} = +160 kJ/mol \qquad \text{(Equation 4.26)}$$

$$C + H_2O \rightarrow CO + H_2 \qquad \Delta H^\circ_{298} = +119 kJ/mol \qquad \text{(Equation 4.27)}$$

$$C + 2H_2 \leftrightarrow CH_4 \qquad \Delta H^\circ_{298} = -87.4 kJ/mol \qquad \text{(Equation 4.28)}$$

$$CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \Delta H^\circ_{298} = -41 kJ/mol \qquad \text{(Equation 4.20)}$$

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O \qquad \Delta H^\circ_{298} = -206 kJ/mol \qquad \text{(Equation 4.29)}$$

The overall gasification reaction is exothermic. Gasification temperatures higher than 1300°C results in a chemical equilibrium leading to a synthesis gas containing mainly hydrogen and carbon monoxide, with trace elements of methane and other hydrocarbons. High pressures reduce the yield of hydrogen, but improve the economics by producing high pressure hydrogen. Bechtel (2003) provided a design for a coal to hydrogen plant that used Global Energy’s two stage gasifier which employs full slurry quench to control the outlet temperature and to maximise hydrogen and CO production while minimising the methane make. Soot and ash particles, together with water-soluble components, are removed with the water quench. Particulates are removed from the syngas using a hot cyclone to remove 90% of the particulates followed by an advanced dry char filtration system. No particulate emissions were reported in the literature.

The next stage of the process is acid gas removal and shift reaction. There are two possible configurations: the “sweet” shift process where the acid gas from the syngas is removed prior to the shift reactor, while in the “sour” shift process, the acid gas removal is performed after the shift process. The “sweet” shift process is usually chosen to prevent sulphur poisoning of the catalyst in the shift reactor, especially the one used at the lowest temperature. According to Häussinger et al. (2012a), the development of sulphur-tolerant shift catalysts make “sour” shift processes possible and enables the shift reaction to take place without prior removal of sulphur. The sulphur compounds, hydrogen sulphide, carbonyl sulphide, and carbon dioxide can be removed in a single stage Rectisol wash. Rutkowski (2008) employed a "sour" shift process where an amine unit removes the acid gas (H_2S, CO_2, etc.) after the shift reaction.

Pure oxygen will require an air separation unit (ASU) which will increase the production cost of hydrogen from coal, but it provides significant advantages such as:

- avoiding the need to remove nitrogen from the product stream
- smaller volumes of gas flowing through the reactors
- higher concentration of CO_2 in the product stream from the shift reactor for easier separation

The process flow diagram of hydrogen production through coal gasification is shown in Figure 4.29. The design follows the principles from Bechtel (2003) and employs a "sour" shift process to remove acid gases prior to shift, followed by a PSA unit to separate hydrogen from the stream after shift.

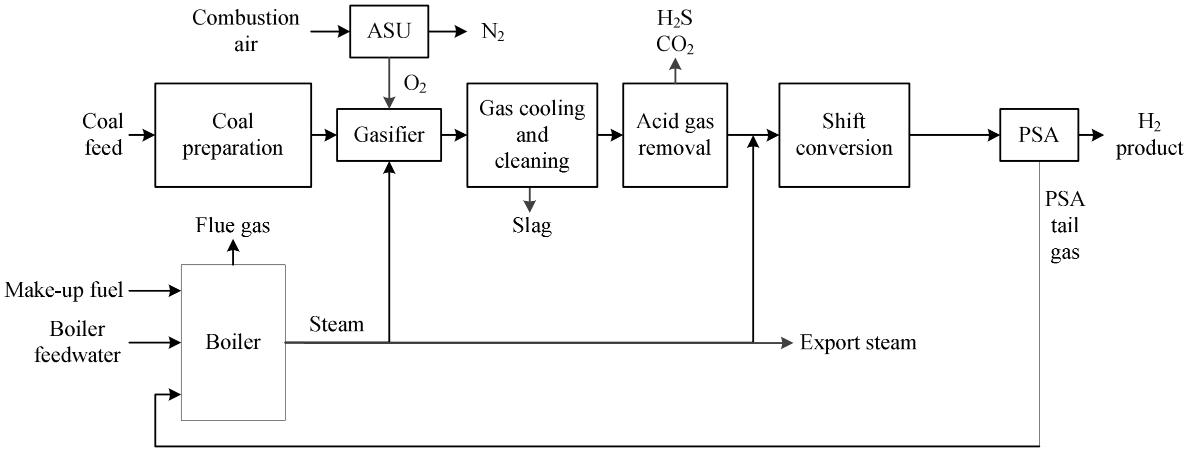


Figure 4.29: Hydrogen production via the coal gasification route

4.5.2.3.1. Material flows

The material flows for the coal gasification hydrogen plant is summarised in Table 4.67. The coal to hydrogen plant by Rutkowski (2008) was taken to be the baseline case, so the coal consumption, process water, wastewater, emissions and ash data were adopted from here. The NO_x emissions were adopted from Bechtel (2003) and cooling water and wastewater values were adopted from Leonard et al. (2007). All designs from the literature reported an electricity generation component using a steam turbine. In order to maintain consistency with the steam reformer design which exports steam, the steam turbine component is removed. The export steam figure in Table 4.67 is adapted from Buchanan et al. (2003) and adjusted to match the steam parameters used in this analysis. Full details of this process are covered in Appendix A.36. No CH_4, N_2O, VOC, and PM_{10} emission data have been reported for coal gasification hydrogen plants. Due to the lack of information for these data, these emissions to air were calculated using the emission factors for IGCC plants reported by NETL (2010).

The Australian black coal has a higher ash content than the Pittsburgh No.8 coal used in Rutkowski (2008), i.e. 21.2 wt% as compared to 9.9 wt% (see Chapter 0 for Australian coal composition and Appendix A.27 for Pittsburgh No.8 composition). The Australian black coal also has a lower hydrogen content than the Pittsburgh No.8 coal used in Rutkowski (2008), but this was assumed to have negligible effect on the material data given that hydrogen is produced from either steam or coal in a complex gasification reaction. Modification of the environmental data to reflect Australian data is necessary. This is performed in Appendix A.37.

Several coal-to-hydrogen studies and their reported material flows are included in Appendix A.38.

Table 4.67: Material flow data for baseline coal gasification hydrogen plant

Inventory data	**Units**	**Hydrogen plant**	**Electricity material flows** [a]	**Total**	**Category**
Input					
Black coal	t/t H_2	8.51	1.26	9.77	Feedstock
Cooling water makeup	t/t H_2	11.7	6.58	18.3	Freshwater Withdrawal
Demineralised water	t/t H_2	32.2	3.46E-01	32.5	Freshwater Withdrawal
Output					
Export steam	t/t H_2	16.8	0	16.8	Byproduct
Cooling water blowdown	t/t H_2	1.83	6.92E-01	2.52	Saline Water Generation
Steam blowdown	t/t H_2	1.53	3.46E-01	1.88	Saline Water Generation
CO_2	t/t H_2	20.60	2.71	23.3	Global Warming Potential
CH_4	t/t H_2	7.42E-05	4.39E-05	1.18E-04	Global Warming Potential
N_2O	t/t H_2	8.55E-08	1.98E-05	1.99E-05	Global Warming Potential
VOC	t/t H_2	5.25E-07	2.30E-08	5.48E-07	Photochemical Oxidation Potential
CO	t/t H_2	8.86E-04	3.15E-04	1.20E-03	Photochemical Oxidation Potential
NO_x	t/t H_2	5.75E-03	6.16E-03	1.19E-02	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t H_2	7.99E-02	1.63E-08	7.99E-02	Acidification Potential
PM_{10}	t/t H_2	7.50E-04	4.42E-04	1.19E-03	Particulate Matter Formation
Ash	t/t H_2	1.57E+00	2.67E-01	1.84	Solid Waste Generation

[a] Electricity assumed to be generated using PCST power station (see Table 4.36)

4.5.2.3.2. Capital cost

Figure 4.30 shows coal gasification hydrogen plant capital costs from various literature plotted against their capacities. The data for these plants are found in Appendix A.39. It is shown that the capacity range of coal gasification hydrogen plants is narrower than steam reforming plants. Similar to the SMR hydrogen plant case, these plant capital costs are representative of bare erected costs. A curve of best fit was plotted through the data points as given by Equation 4.30.

$$I = 1.36 \times 10^{5} Q^{0.73} \qquad \text{(Equation 4.30)}$$

where I = Plant capital cost in 2012A$

Q = Plant production capacity in t/yr

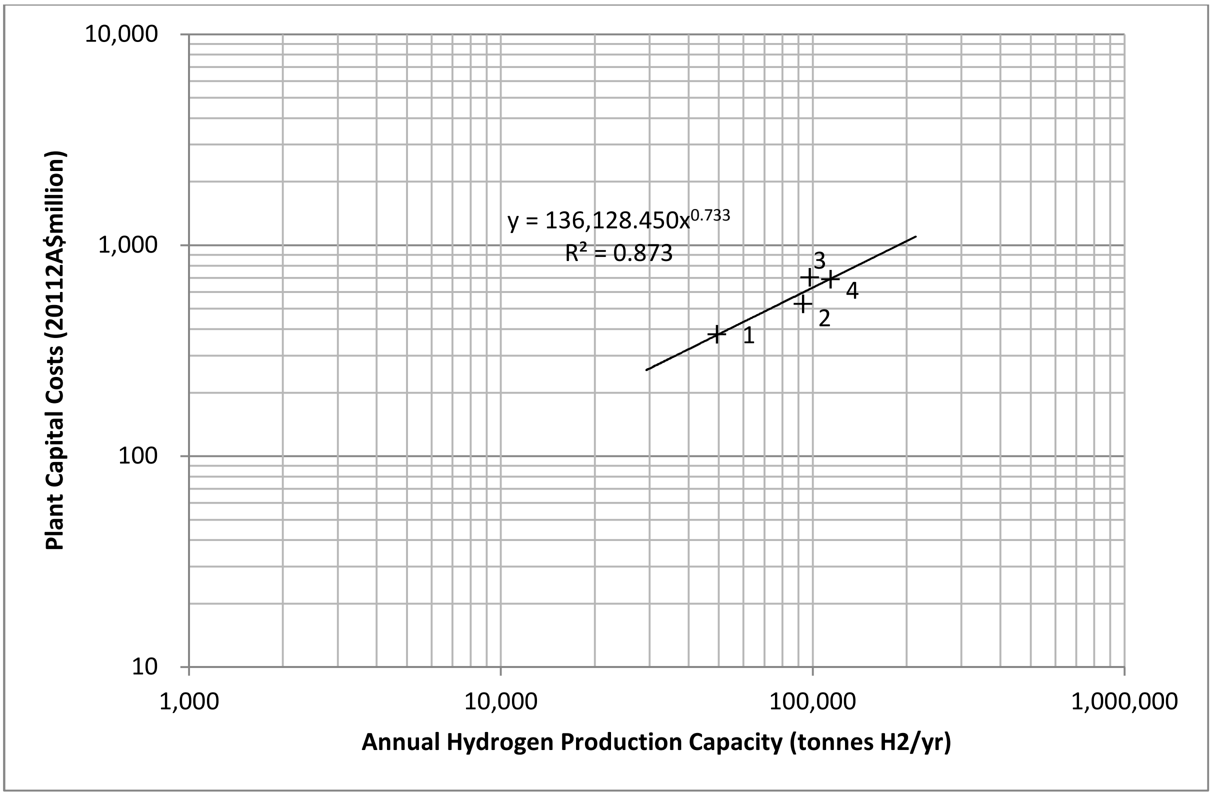


Figure 4.30: Coal gasification hydrogen plant costs in 2012 Australian dollars against production capacity in t H_2/yr.

Note: The plants costs found in literature are (1) Simbeck & Chang (2002), (2) Rutkowski (2008), (3) Gray & Tomlinson (2001) and (4) Klett et al. (2002).

Point (2) on Figure 4.30 corresponded to the capital cost as reported by Rutkowski (2008) was chosen as the baseline capital cost for a coal gasification hydrogen plant in this study. Rutkowski (2008) reported the baseline uninstalled capital cost of a 284 t/day coal gasification hydrogen plant to be US$ 256 million in 2005 U.S. dollars. Included in this total are the costs for coal handling preparation and feed system, feedwater system, gasifier and accessories, ASU, hydrogen separation and gas clean-up system, heat recovery steam generator (HRSG) system, ash handling system, instrumentation, buildings and structures. Rutkowski (2008) applied specific installation cost factors for each cost item, resulting in a baseline installed cost of $313 million in 2005 U.S. dollars (2012A$ 527 million). As the steam turbine component is removed, the capital costs for the steam turbine (2005US$ 15.8

million) and cooling water system (2005US$ 6.36 million) are taken out from the direct capital costs. This then gives a baseline installed cost of 2005US$ 291 million (2012A$ 490 million).

In order for this plant to be compared with the SMR hydrogen plant, the capacity was adjusted to 380 t/day to match that of the SMR hydrogen plant. This gives an installed cost of 2012A$ 607 million. Taking into account engineering and construction management (assumed to be 25% of direct capital cost), the total capital cost of the coal to H_2 plant was found to be $757 million in 2012 Australian dollars.

4.5.2.3.3. Operating cost

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the coal gasification process, there are seven process zones, which are the coal preparation, ASU, gasifier, syngas cooling and cleaning, shift and PSA as one unit, acid gas removal and steam boiler. An additional operator is required for the control room. Hence, eight process operators are required.

Rutkowski (2008) reported a total of 2005$ 2.4 million/yr ($25.92/t H_2) that was allocated to other variable operating costs, which included catalysts and sorbents. In addition, a total of 2005 US$ 101,000/yr ($1.08/t H_2) was allocated to waste treatment costs and 2005 US$894,000/yr ($9.59/t H_2) was allocated to solid waste disposal costs. The solid waste disposal cost is adjusted to account for the higher ash production using Australian coal. For this analysis, it was assumed that $26/t H_2 in 2012 Australian dollars is allocated for other costs such as catalysts and sorbents, $1.10/t H_2 is allocated for waste treatment costs, and $21/t H_2 for solid waste disposal costs.

Table 4.68 shows the operating cost model for the baseline coal gasification hydrogen plant including waste treatment and disposal costs and revenue from export steam.

Table 4.69 summarises the total operating cost for the coal gasification hydrogen plant. The costs for the options for inclusion of waste treatment and disposal costs and inclusion of revenue from export steam are given. The waste treatment and disposal costs do not significantly affect the hydrogen cost as they make up only 3 - 4% of the total operating costs. Although the coal gasification hydrogen plant produces more export steam than the steam reforming H_2 plant, the electricity costs are more than six times higher, thus the cash operating costs are higher for the coal gasification H_2 plant.

Table 4.68: Operating cost model for baseline coal gasification hydrogen plant (Costs are expressed in 2012A$)

Plant capacity	380	t/day			
Plant availability	85%				
Annual actual production	118,000	t/yr			
Fixed capital investment	757	$ million			
Capital exponent,ψ (I=αQψ)	0.733				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per tonne H_2 ($/t H_2)**
Raw materials		Unit usage (/t H_2)	Unit cost ($/unit)		
Black coal fuel/feedstock	t	8.51	33.1	33.27	281.97
Utilities		Unit usage (/t H_2)	Unit cost ($/unit)		
Electricity	MWh	3.462366503	85.2	34.80	294.95
Cooling water	m3	609	0.0770	5.54	46.92
Demineralised water	t	32.2	1.50	5.69	48.25
Waste treatment				0.13	1.10
Solid waste disposal				2.48	21.00
Other				3.07	26.00
Total variable costs				**84.98**	**720.20**
Byproducts		Unit usage (/t H_2)	Unit cost ($/unit)		
Byproduct steam	t	16.81	25.5	-50.58	-428.62
Total byproduct costs				**-50.58**	**-428.62**
Operating labour		No.	Salary ($/yr)		
Operators/shift		8			
Shift teams		5			
Total shift operators		40	87,000	3.48	29.49
Total operating labour costs				**3.48**	**29.49**
Payroll overheads		40	% total operating labour cost	1.39	11.80
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.73	6.19
Maintenance labour		1		7.57	64.16
Maintenance materials		1		7.57	64.16
Consumables store			10	0.49	4.13
Plant overheads			100	4.87	41.29
Laboratory			10	0.49	4.13
Insurance		1		7.57	64.16
Property taxes		1		7.57	64.16
Total fixed costs				**41.73**	**353.65**
Total manufacturing costs				**76.14**	**645.22**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	3.54	30.01
Marketing costs		5	Total production cost	4.43	37.51
Research and development costs		5	Total production cost	4.43	37.51
General expenses				**12.39**	**105.04**
Total product cost				**88.53**	**750.26**

Table 4.69: Total operating cost of the coal gasification hydrogen plant (Costs are expressed in 2012A$)

Capacity (t/day)		380			
Output (t/year)		117,895			
Annualised capital costs (A$/t H_2)		681			
Waste treatment and disposal costs		Excluded		Included	
Export steam revenue @ $25.5/t		Excluded	Included	Excluded	Included
Cash operating costs	Variable costs ($/t H_2)	672	672	720	720
	Fixed costs ($/t H_2)	354	354	354	354
	Other costs ($/t H_2)	167	97.2	175	105
	Total ($/t H_2)	1,190	694	1,250	750
Total operating costs ($/t H_2)		1,870	1,380	1,930	1,430
Total operating costs ($/GJ H_2)		13.2	9.67	13.6	10.0

4.5.2.4. SUBSTITUTION IMPACTS FOR HYDROGEN PRODUCTION

In the event of a natural gas scarcity, hydrogen produced from steam reforming of natural gas is either substituted with hydrogen produced via black coal gasification or substituted with CSG as a fuel for the steam reforming process.

Table 4.70 summarises the substitution impacts for hydrogen production. For the operating costs, the revenue from steam export and the wastewater treatment and disposal costs were included. Substitution of natural gas with black coal in hydrogen production will cause an increase in most environmental categories. Decreases were reported for the photochemical oxidation potential and associated water withdrawal categories, similar to the grid electricity generation case where natural gas is substituted for black coal. Natural gas extraction and processing reported higher values of photochemical oxidation emissions and associated water production than for black coal. As for the economic impact indicators, substitution of natural gas with black coal will cause a decrease in operating costs, but this is negated by a higher value annualised capital costs. Full details of the calculations of the substitution indicators are shown in Appendix A.40.

Table 4.70: Substitution impact indicators for hydrogen production in Australia

Option	Hydrogen	
Feedstock	NG→BlC	NG→CSG
Technology	SMR→CG	SMR
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	+ 7.84E-09	- 1.14E-10
Acidification Potential (ADP)	+ 1.56E-08	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 1.65E-09	- 3.93E-09
Particulate Matter Formation (PMF)	+ 3.63E-10	- 9.29E-11
Freshwater Withdrawal (FWW)	+ 9.23E-11	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 1.44E-08
Saline Water Generation (CWG)	+ 1.17E-11	- 7.17E-13
Solid Waste Generation (SWG)	+ 1.80E-07	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+ 212.0	-
Cash operating costs	+ 61.7	- 46.9
Total operating costs	+ 273.0	- 46.9

Legend: '+' sign denotes increase in impacts, '-' sign denotes decrease in impacts, NG=Natural Gas, BlC=Black Coal, CSG=Coal Seam Gas, SMR=Steam Methane Reforming, CG=Coal Gasification
Note: Environmental impact indicators include upstream and downstream impacts.

4.5.3. AMMONIA

4.5.3.1. INTRODUCTION

The percentage breakdowns of global ammonia usage are shown in Figure 4.31. About 80% of ammonia usage is mainly in the manufacture of fertiliser, while the remainder is for the manufacture of other chemicals and for industrial use. In fact, every nitrogen atom in industrially produced chemical compounds comes directly or indirectly from ammonia (Appl 2012a).

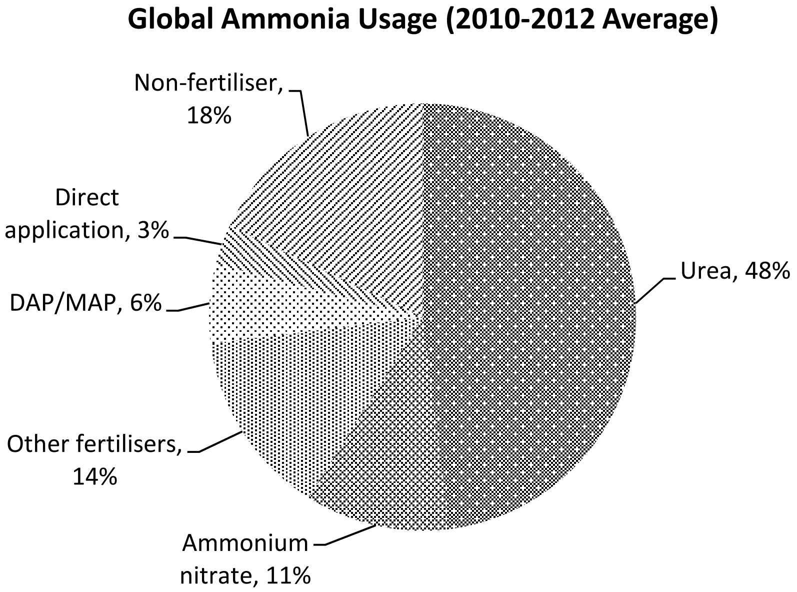


Figure 4.31: Global ammonia usage (PotashCorp 2013)

Ammonia capacity in Australia was estimated to be 1.7 million tonnes per year in 2008 (WYLD Group et al. 2008). Ammonia plants are located in Brisbane (Gibson Island), Newcastle (Kooragang Island), Western Australia (Kwinana and Karratha), Queensland (Moranbah and Phosphate Hill), and in Yarwun, Gladstone (EPA 2001). Many of these ammonia plants are not standalone plants, but are integrated into a wider process (e.g. manufacture of urea, ammonium nitrate and sodium cyanide). At a glance, ammonia can be seen as a precursor to more chemicals than other derivatives in Figure 4.24 (see Chapter 4.5.1).

Fertiliser Australia (2012) explained that ammonia is the basis for all major, manufactured nitrogen fertilisers in Australia. These fertilisers include urea, ammonia sulphate, ammonium nitrate, ammonium phosphate and anhydrous ammonia, which is ammonia in liquefied gas form. Urea is manufactured by reacting ammonia with carbon dioxide formed in the production of hydrogen in the first step of the ammonia manufacturing process. Ammonium sulphate is produced as a by-product from a number of manufacturing processes of which nickel refining is the most significant source in Australia.

Several examples of ammonia usage was provided by Linde (2013) and Appl (2012a) in Table 4.71. Two applications of ammonia which is important to the Australian context are the manufacture of explosives, which is used in the mining industry, and the manufacture of sodium cyanide, which is used by the gold mining industry to extract gold from its ore.

Table 4.71: Applications of ammonia in industry

Appl (2012a)	Linde (2013)
• Production of fibres (e.g. polyamides, urea-formaldehyde-phenol resins, melamine-based resins, polyurethanes and polyacronitrile • Manufacture of explosives • Production of hydrazines, amines, amides and nitriles • Manufacture dyes and pharmaceuticals • Manufacture inorganic compounds (e.g. nitric acid, sodium nitrate, sodium cyanide, ammonium chloride, ammonium bicarbonate) • Remove SO_2 and NO_x from flue gases of fossil fuel power plants • Used as a solvent • Nitriding of steel	• Neutralise acid constituents of crude oil during the refining process • Purification of flue gas and water in fossil fuel power plants • Extraction of copper, nickel and molybdenum from their ores • Create a reducing atmosphere of hydrogen and nitrogen for metal heat treatment • Processing agent in the manufacture of pharmaceuticals • Substitute for calcium in the pulping of wood • Used as a refrigerant gas • Stabilisation of raw rubber latex during transportation and storage • Electronic and semiconductor applications

4.5.3.2. NATURAL GAS PATHWAY

About 85% of world ammonia production comes from steam reforming of natural gas or other light hydrocarbons (EFMA 2000). To produce ammonia, a pure mixture of nitrogen and hydrogen in a stoichiometric ratio of 1:3 is required.

One commercial route is based on the Uhde design as shown in Figure 4.32. The process involves pre-treatment, two stages of reforming, high and low shift, acid gas removal, methanation, compression (not shown) and ammonia synthesis. Appl (2012b) and EFMA (2000) covered the process steps of the Uhde method in detail.

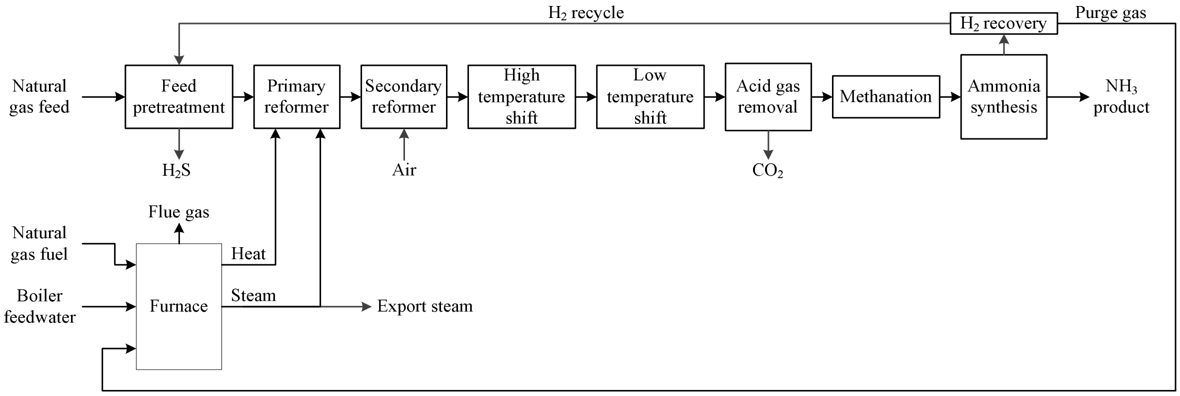


Figure 4.32: Ammonia production from natural gas via the Uhde process

The feed gas is preheated in the primary reformer convection section and pre-treated to remove sulphur and sulphur compounds to avoid poisoning the sensitive catalysts used in the process. The sulphur compounds are hydrogenated to H_2S using a cobalt-molybdenum catalyst and absorbed on pelletised zinc oxide. The reactions are shown below in Equation 4.31 and Equation 4.32 below. The hydrogen is usually recycled from the synthesis section.

$$R-SH+H_2 \leftrightarrow H_2S+RH \qquad (\text{Equation 4.31})$$

$$H_2S+ZnO \leftrightarrow ZnS+H_2O \qquad (\text{Equation 4.32})$$

To achieve the required stoichiometric hydrogen/nitrogen ratio for ammonia synthesis, the reforming section is split into two sections. The primary reformer contains nickel containing reforming catalyst in tubes that are indirectly heated where 65% conversion occurs. Heat for the primary reforming process is supplied by burning natural gas in the burners of the radiant box containing the tubes. The composition of the gas leaving the primary reformer is given by close approach to the chemical equilibria shown in Equation 4.19 and Equation 4.20. The gas then enters the secondary reformer, which is a refractory-lined vessel filled with nickel catalyst. Process air, which acts as the source of nitrogen for ammonia synthesis, is fed into the secondary reformer. Some of the gas is combusted with air to raise the temperature to about 1200°C prior to entering the secondary reformer to increase conversion of the endothermic reforming reaction. The syngas exits the secondary reformer at around 1000°C and residual methane content of 0.5% or lower is attained.

$$CH_4+H_2O \xrightarrow{heat} CO+3H_2 \qquad \Delta H^{\circ}_{298}=+206kJ/mol \qquad (\text{Equation 4.19})$$

$$CO+H_2O \leftrightarrow CO_2+H_2 \qquad \Delta H^{\circ}_{298}=-41kJ/mol \qquad (\text{Equation 4.20})$$

The gas from the secondary reformer is cooled to between 320 and 350°C before entering the high temperature shift reactor, containing an iron-chromium catalyst. The temperature will increase by 50-70°C and the residual CO_2 content will reach around 3 percent. The gas is cooled to 210°C for the low temperature shift, which is carried out on a copper-zinc-alumina catalyst. This lowers the carbon monoxide concentration to 0.1-0.3 vol%. A steam surplus is necessary for thermodynamic reasons and to suppress the creation of undesirable by-products, particularly carbon deposition. The shift reaction is shown in Equation 4.20 above.

Further purification is required to remove carbon dioxide and carbon monoxide which are poisons for the ammonia synthesis catalyst. Methanation is used to reduce the concentrations of carbon oxides to levels below 10ppm. The reactions outlined in Equation 4.33 and Equation 4.34 are carried out at a pressure of 25-35 bar and temperature 250 to 350°C in the presence of nickel catalyst.

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O \qquad \Delta H^{\circ}_{298} = -206\, kJ/mol \qquad \text{(Equation 4.33)}$$

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \qquad \Delta H^{\circ}_{298} = -165\, kJ/mol \qquad \text{(Equation 4.34)}$$

The gas is compressed to 100-250 bar and fed into the ammonia synthesis loop which is shown in Figure 4.33. Equation 4.31 shows the main elements of the ammonia synthesis loop: Compressors, reactors, cooling units to condense the ammonia product and recover heat, separation units to separate ammonia from unreacted gas, purge gas removal equipment, and recirculation equipment to move the unreacted gas back to the reactor. The ammonia synthesis loop uses centrifugal compressors for synthesis gas compression. In the reactors, the Haber-Bosch reaction takes place at temperatures 350 - 550°C in the presence of an iron catalyst. Equation 4.35 describes the exothermic reaction that occurs in the convertor. Each pass through the catalyst will only result in partial conversion (25 - 35%). Ammonia is separated from the unreacted gas by condensation and the unreacted gas is supplemented with fresh synthesis gas before it is returned to the convertor. The concentration of inert gases such as argon and methane is maintained by withdrawing a small amount of purge gas, which is fed into the furnace.

$$N_2 + 3H_2 \leftrightarrow 2NH_3 \qquad \Delta H^{\circ}_{298} = -92.44\, kJ/mol \qquad \text{(Equation 4.35)}$$

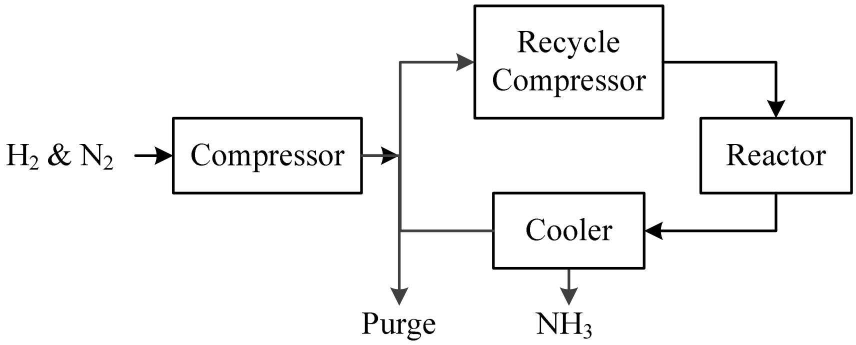


Figure 4.33: Process flow diagram of ammonia synthesis loop

The second route is called the Linde Ammonia Concept (LAC) and is shown in Figure 4.34. The main differences between the LAC and the Uhde design is that it utilises an air separation unit to produce a pure nitrogen stream from air and it separates impurities from the H_2 using a PSA. The secondary reformer and low temperature shift reactors are not required. A nitrogen wash is performed on the H_2 stream produced from an arrangement that closely resembles the hydrogen plant design from Section 4.5.2.2.

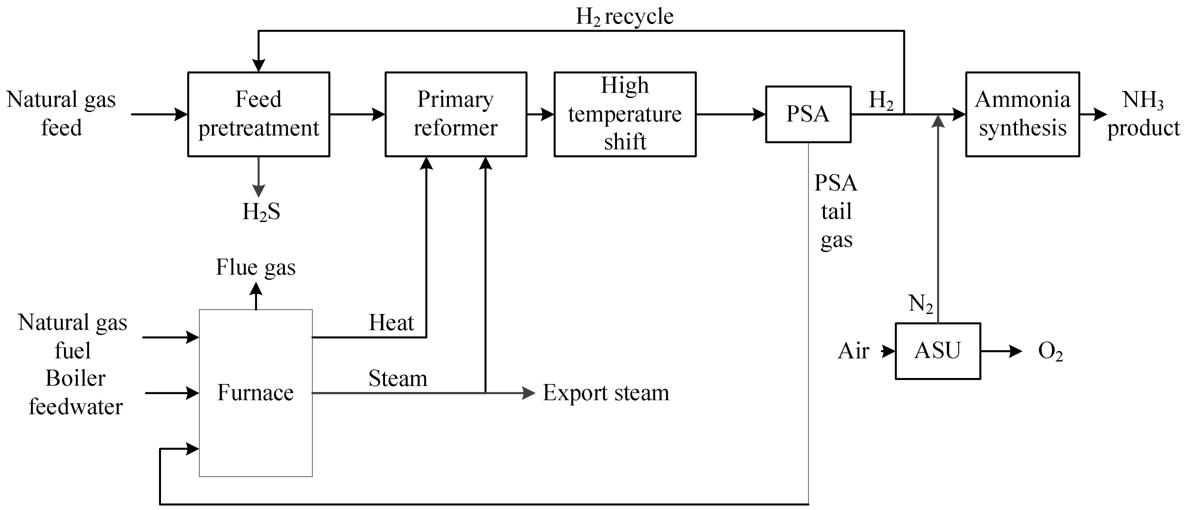


Figure 4.34: Ammonia production from natural gas via the Linde process

The LAC is chosen for this analysis as it shares many similar equipment with the steam reforming process in Chapter 4.5.2.2, such as the PSA. This then allows us to model the environmental impacts of the NH_3 plant using the material flows of a H_2 plant together with additional units (e.g. ASU and NH_3 synthesis unit.

4.5.3.2.1. Material flows

Material flow data for NH_3 production have been published by the European Fertilizer Manufacturers Association (EFMA), the Australian National Pollutant Inventory (NPI) and the Australian Environmental Protection Authority (EPA) (see Appendix A.41). The EFMA data represents the Best Available Technique (BAT) for NH_3 production from light hydrocarbons (e.g. natural gas) using the conventional Uhde method and from partial oxidation of heavy hydrocarbons. Material flows for two existing NH_3 plants in Australia, the Yara Pilbara plant and the Burrup plant, are included in Appendix A.41. Both plants reported lower NO_x and SO_2 emissions than the BAT, thus demonstrating that NH_3 plants in Australia perform at par or better than the BAT.

For this analysis, the material flows of the NH_3 plant are estimated by combining that of a conventional steam reforming H_2 plant with environmental data for an ASU and a NH_3 synthesis unit. The H_2 plant material flow data is obtained from Table 4.63 in Section 4.5.2.2.1 and is adjusted according to Equation 4.36.

$$\text{Material flows}(NH_3) = \text{Material flows}(H_2) \times \frac{1\,\text{t}\,NH_3}{0.18\,\text{t}\,H_2} \qquad (\text{ Equation 4.36 })$$

The power and cooling requirements for the ASU (see Appendix A.42) and the NH_3 synthesis loop (see Appendix A.43) were adopted from Morgan (2013). The electricity requirement for the ASU unit alone was nearly identical to the whole H_2 plant. However, the highest electricity requirement was from the compressor prior to the NH_3 synthesis loop due to the work required to bring the H_2 and N_2 feed up to 150 bar.

Table 4.72 summarises the combined environmental data that make up the material flows of a LAC NH_3 plant.

Table 4.72: Material flow data for ammonia production via LAC steam methane reforming

Inventory data	Units	Hydrogen plant	ASU	NH_3 synthesis process	Electricity material flows [a]	Total	Category
Input							
Natural gas feedstock	t/t NH_3	5.60E-02	0	0	0	5.60E-02	Feedstock
Natural gas fuel	t/t NH_3	5.11E-01	0	0	1.36E-02	5.25E-01	Fuel
Black coal	t/t NH_3	0	0	0	2.11E-01	2.11E-01	Fuel
Cooling water makeup	t/t NH_3	1.00	5.81E-02	8.06E-01	1.19	3.05	Freshwater Withdrawal
Demineralised water	t/t NH_3	4.47	0	0	6.62E-02	4.54	Freshwater Withdrawal
Output							
Excess steam	t/t NH_3	2.51	0	0	0		
Cooling water blowdown	t/t NH_3	1.56E-01	9.07E-03	1.26E-01	1.29E-01	4.20E-01	Saline Water Generation
Steam blowdown	t/t NH_3	0.213	0	0	6.62E-02	2.79E-01	Saline Water Generation
CO_2	t/t NH_3	1.55	0	0	4.91E-01	2.04	Global Warming Potential
CH_4	t/t NH_3	1.37E-05	0	0	1.07E-05	2.44E-05	Global Warming Potential
N_2O	t/t NH_3	2.78E-07	0	0	4.29E-07	7.08E-07	Global Warming Potential
VOC	t/t NH_3	6.67E-06	0	0	3.40E-06	1.01E-05	Photochemical Oxidation Potential
CO	t/t NH_3	1.02E-04	0	0	1.09E-03	1.19E-03	Photochemical Oxidation Potential
NO_x	t/t NH_3	1.21E-04	0	0	7.33E-05	1.94E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t NH_3	1.34E-06	0	0	3.32E-07	1.67E-06	Acidification Potential
PM_{10}	t/t NH_3	8.96E-06	0	0	7.61E-05	8.51E-05	Particulate Matter Formation

[a] Electricity assumed to be generated using Australian reference grid electricity fuel mix (see Appendix A.20)

4.5.3.2.2. Capital cost

Appl (2012a) published the capital investment cost of a 2000 t/day NH_3 plant using steam reforming of natural gas to be $250 million in 2004 U.S. dollars ($421 in 2012 Australian dollars). This cost included inside battery limits and a 45,000 t ammonia tank with refrigeration. Costs related to off-site were excluded. No detail was given regarding the design of NH_3 plant (e.g. Uhde or LAC).

The capital cost of the steam reforming NH_3 plant can be estimated by calculating the capital costs of the H_2 plant, ASU and NH_3 synthesis plant individually.

Capital costs for the H_2 plant were adapted from Section 4.5.2.2.2 and the size was adjusted to meet the H_2 requirements of the NH_3 plant using the ratio of 0.18 t H_2/t NH_3. For a 2000 t/day NH_3 plant, a 360 t/day H_2 plant was required.

Costs for the ASU and NH_3 synthesis plant were calculated and reported by Morgan (2013). Using a ratio of 0.82 t N_2/t NH_3, the N_2 feedstock required for a 2000 t/day NH_3 production was found to be 1647 t/day. The capital costs of each component are summarised in Table 4.73 and the costs are reported in 2012 Australian dollars. Details on the adjustment of capital costs are located in Appendix A.44. The calculated direct plant cost is similar to the capital investment cost reported by Appl (2012a).

Table 4.73: Capital cost of a 2000 t/day LAC concept ammonia plant (Costs are expressed in 2012A$)

Plant component	Capital cost
Hydrogen plant	$ 219 million
ASU	$ 31.2 million
Ammonia synthesis plant	$ 103 million
Direct plant cost	**$ 353 million**
Engineering and construction management [a]	$ 88.3 million
Total plant cost	**$ 441 million**

[a] Assumed to be25% of direct plant cost.

4.5.3.2.3. Operating cost

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the LAC process, there are three process zones that are similar to the steam reforming process, which are the pre-treatment, reformer and furnace as one zone, and the shift and PSA as one zone. On top of these, there are two additional zones, which are the ASU and the ammonia synthesis unit. An additional operator is required for the control room. Hence, six process operators are required in total.

The rest of the parameters remained the same as that from the steam reforming hydrogen plant. These are adjusted to reflect the costs per t ammonia product. Table 4.74 and Table 4.75 show the operating cost models for ammonia production from natural gas and CSG without the revenue from steam export. Costs are expressed in 2012 Australian dollars.

Table 4.74: Operating cost model for a steam methane reforming ammonia plant using natural gas feedstock (Costs are expressed in 2012A$)

Plant capacity	2,000	t/day
Plant availability	85%	
Annual actual production	620,500	t/yr
Fixed capital investment	442	$ million
Capital exponent,ψ (I=αQψ)	0.7	
Cost year	2012	AUD$

Operating costs				**Annual cost ($ million)**	**Cost per tonne NH_3 ($/t NH_3)**
Raw materials		Unit usage (/t NH_3)	Unit cost ($/unit)		
Natural gas fuel/feedstock	t	0.567	179	62.80	101.22
Utilities		Unit usage (/t NH_3)	Unit cost ($/unit)		
Electricity	MWh	0.831	70.00	36.09	58.17
Cooling water	m3	97.1	0.08	4.64	7.48
Demineralised water	t	4.47	1.50	4.16	6.70
Catalysts and sorbents				1.97	3.18
Total variable costs				**109.66**	**176.73**
Byproducts		Unit usage (/t NH_3)	Unit cost ($/unit)		
Byproduct steam	t	2.51	25.50	- 39.68	- 63.94
Total byproduct costs				**- 39.68**	**- 63.94**
Operating labour		No.	Salary ($/yr)		
Operators/shift		6			
Shift teams		5			
Total shift operators		30	87,000	2.61	4.21
Total operating labour costs				**2.61**	**4.21**
Payroll overheads		40	% total operating labour cost	**1.04**	1.68
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.55	0.88
Maintenance labour		1		4.42	7.12
Maintenance materials		1		4.42	7.12
Consumables store			10	0.37	0.59
Plant overheads			100	3.65	5.89
Laboratory			10	0.37	0.59
Insurance		1		4.42	7.12
Property taxes		1		4.42	7.12
Total fixed costs				**26.25**	**42.30**
Total manufacturing costs				**96.24**	**155.09**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	4.48	7.21
Marketing costs		5	Total production cost	5.60	9.02
Research and development costs		5	Total production cost	5.60	9.02
General expenses				**15.67**	**25.25**
Total product cost				**111.90**	**180.34**

Table 4.75: Operating cost model for a steam methane reforming ammonia plant using CSG feedstock (Costs are expressed in 2012A$)

Plant capacity	2,000	t/day			
Plant availability	85%				
Annual actual production	620,500	t/yr			
Fixed capital investment	442	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	AUD$			
Operating costs				**Annual cost ($ million)**	**Cost per tonne NH_3 ($/t NH_3)**
Raw materials		Unit usage (/t NH_3)	Unit cost ($/unit)		
Coal seam gas fuel/feedstock	t	0.567	124	43.73	70.47
Utilities		Unit usage (/t NH_3)	Unit cost ($/unit)		
Electricity	MWh	0.831	70.00	36.09	58.17
Cooling water	m3	97.1	0.08	4.64	7.48
Demineralised water	t	4.47	1.50	4.16	6.70
Catalyst and sorbents				1.97	3.18
Total variable costs				**90.59**	**145.99**
Byproducts		Unit usage (/t NH_3)	Unit cost ($/unit)		
Byproduct steam	t	2.51	25.50	-39.68	-63.94
Total byproduct costs				**-39.68**	**-63.94**
Operating labour		No.	Salary ($/yr)		
Operators/shift		6			
Shift teams		5			
Total shift operators		30	87,000	2.61	4.21
Total operating labour costs				**2.61**	**4.21**
Payroll overheads		40	% total operating labour cost	**1.04**	1.68
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.55	0.88
Maintenance labour		1		4.42	7.12
Maintenance materials		1		4.42	7.12
Consumables store			10	0.37	0.59
Plant overheads			100	3.65	5.89
Laboratory			10	0.37	0.59
Insurance		1		4.42	7.12
Property taxes		1		4.42	7.12
Total fixed costs				**26.25**	**42.30**
Total manufacturing costs				**77.16**	**124.35**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	3.59	5.78
Marketing costs		5	Total production cost	4.49	7.23
Research and development costs		5	Total production cost	4.49	7.23
General expenses				**12.56**	**20.24**
Total product cost				**89.72**	**144.59**

The total operating cost for ammonia production from natural gas and CSG is summarised in Table 4.76.

Table 4.76: Total operating costs for steam reforming ammonia plants using natural gas (NG) and CSG feedstock (Costs are expressed in 2012A$)

Capacity (t/day)		2000			
Output (t/year)		620,500			
Annualised capital costs (A$/t NH_3)		75.5			
Export steam revenue @ $25.5/t		Excluded		Excluded	
Feedstock		NG	CSG	NG	CSG
Cash operating costs	Variable costs ($/t NH_3)	177	146	177	146
	Fixed costs ($/t NH_3)	42.3	42.3	42.3	42.3
	Other costs ($/t NH_3)	35.6	30.7	25.3	25.3
	Total ($/t NH_3)	255	219	180	145
Total operating costs ($/t NH_3)		330	294	256	220

4.5.3.3. COAL GASIFICATION

For heavier feedstocks such as black coal, ammonia is produced using the partial oxidation gasification route. The various reactions involved in coal gasification can be found in Section 4.5.2.3. This section will only cover the key reactions. The upstream hydrogen production section is identical to the coal to hydrogen plant in Figure 4.29. Appl (2012b) and EFMA (2000) covered the process steps of the conventional method in detail.

Hydrocarbons or coal will undergo incomplete combustion in an atmosphere with insufficient oxygen as shown in Equation 4.22 and Equation 4.25.

$$C_aH_b + \frac{a}{2}O_2 \leftrightarrow aCO + \frac{b}{2}H_2 \qquad \text{(Equation 4.22)}$$

$$C + \frac{1}{2}O_2 \rightarrow CO \qquad \Delta H^\circ_{298} = -123 kJ/mol \qquad \text{(Equation 4.25)}$$

Steam is added so that the following reactions occur in parallel to produce hydrogen.

$$C_aH_b + aH_2O \leftrightarrow aCO + \left(a + \frac{b}{2}\right)H_2 \qquad \text{(Equation 4.23)}$$

$$C + H_2O \rightarrow CO + H_2 \qquad \Delta H^\circ_{298} = +119 kJ/mol \qquad \text{(Equation 4.37)}$$

The overall reaction is exothermic so no external heat supply is required. Currently, the Koppers-Totzek, Texaco and Lurgi gasifiers have been used in ammonia plants (Appl 2012b). The raw synthesis gas from partial oxidation of heavy hydrocarbons and coal may contain high amounts of sulphur compounds (mainly H_2S with smaller quantities of COS) and higher CO content than natural gas and other lighter hydrocarbons. Similar to the H_2 plant, the sulphur compounds can either be removed before the shift conversion separate from CO_2 which will be removed after the shift, or removed after the shift together with the CO_2. Figure 4.35 shows a “sour” shift reaction configuration where acid gases are removed prior to the shift. Normally, for partial oxidation processes, only a high temperature shift conversion is used, resulting in a gas with 3-5 vol% carbon monoxide content. Liquid nitrogen washing is a method to remove methane and other hydrocarbons by condensing them, which is free from all impurities but also provides nitrogen for the ammonia synthesis process. The air separation unit then plays a crucial role in providing oxygen for the gasifier and providing nitrogen for the liquid nitrogen wash and as feedstock for ammonia production. The compression and ammonia synthesis stages are virtually identical to that in the steam reforming process.

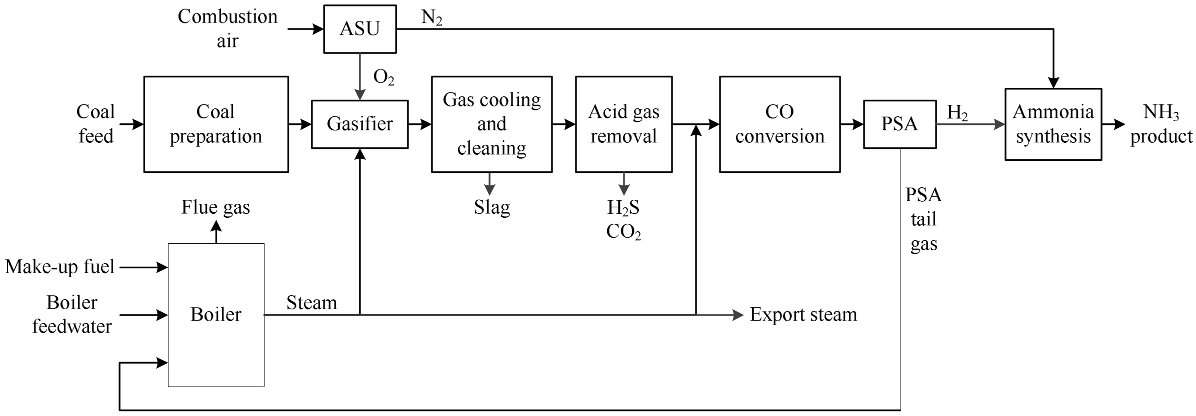


Figure 4.35: Ammonia production via the coal gasification route

4.5.3.3.1. Material flows

There are very few published material flow data for ammonia production from coal. The only data that can be found is from EFMA (2000), which covered emissions for the BAT ammonia production through partial oxidation. The partial oxidation route is virtually identical to the coal to hydrogen plant in Section 4.5.2.3 with the only modifications made being the addition of the ammonia synthesis process. The coal to hydrogen plant already has an ASU built into the design that supplies sufficient nitrogen for the ammonia process. Rutkowski (2008) reported an ASU with a nitrogen production capacity of 23.4 t/t H_2 for its hydrogen plant, which was more than enough than the stoichiometric 4.7 t/t H_2 required for an ammonia plant. The hydrogen material flow data from Section 4.5.2.3.1 were adjusted according to Equation 4.39 to reflect the material flow data of an ammonia plant. The material flow data is shown in Table 4.77.

Table 4.77: Material flow data for ammonia production via partial oxidation of coal

Inventory data	Units	Hydrogen plant	NH_3 synthesis process	Electricity material flows [a]	Total	Category
Input						
Black coal	t/t NH_3	1.50	0	4.55E-01	1.96	Fuel
Cooling water makeup	t/t NH_3	2.06	8.06E-01	2.38E+00	5.25	Freshwater Withdrawal
Process water	t/t NH_3	5.68	0	1.25E-01	5.81	Freshwater Withdrawal
Output						
Cooling water blowdown	t/t NH_3	3.23E-01	1.26E-01	2.51E-01	6.99E-01	Saline Water Generation
Steam blowdown	t/t NH_3	2.70E-01	0	1.25E-01	3.95E-01	Saline Water Generation
CO_2	t/t NH_3	3.63	0	2.51E-01	3.88	Global Warming Potential
CH_4	t/t NH_3	1.31E-05	0	1.25E-01	1.25E-01	Global Warming Potential
N_2O	t/t NH_3	1.51E-08	0	7.17E-06	7.19E-06	Global Warming Potential
VOC	t/t NH_3	9.26E-08	0	8.32E-09	1.01E-07	Photochemical Oxidation Potential
CO	t/t NH_3	1.56E-04	0	1.14E-04	2.70E-04	Photochemical Oxidation Potential
NO_x	t/t NH_3	1.01E-03	0	2.23E-03	3.24E-03	Acidification Potential, Photochemical Oxidation
SO_2	t/t NH_3	7.99E-02	0	5.91E-09	7.99E-02	Acidification Potential
PM_{10}	t/t NH_3	1.32E-04	0	1.60E-04	2.92E-04	Particulate Matter Formation
Ash	t/t NH_3	1.57E+00	0	9.64E-02	1.67	Solid Waste Generation

[a] Electricity assumed to be emissions from PCST power station (see Table 4.36)

4.5.3.3.2. Capital cost

Appl (2012a) published the capital investment cost of a 2000 t/day ammonia plant using partial oxidation of coal to be $650 million in 2004 U.S. dollars ($864 in 2012 Australian dollars). This cost was derived from the capital cost of the steam reforming plant using relative investment indices of 1.0 for natural gas and 2.5 for coal (Appl 2012b).

The capital cost of the partial oxidation NH_3 plant can be estimated by calculating the capital costs of the H_2 plant and NH_3 synthesis plant. Capital costs for the hydrogen plant were adapted from Chapter 4.5.2.3.2 and the size was adjusted to a capacity of 360 t/day to meet the hydrogen requirements of the ammonia plant. Costs for the ammonia synthesis plant were taken from Chapter 4.5.3.2.2 for a 2000 t/day ammonia plant. The capital costs of each component are summarised in Table 4.78 and the costs are reported in 2012 Australian dollars. Details on the adjustment of capital costs are located in Appendix A.45. Engineering and construction management costs were assumed to be 25% of the direct plant cost.

Table 4.78: Capital cost of a 2000t/day coal to ammonia plant (Costs are expressed in 2012A$)

Plant component	Capital cost
Hydrogen plant	$ 583 million
Ammonia synthesis plant	$ 103 million
Direct plant cost	**$ 686 million**
Engineering and construction management [a]	$ 171 million
Total plant cost	**$ 857 million**

[a] Assumed to be25% of direct plant cost.

4.5.3.3.3. Operating cost

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the coal gasification process, there are seven process zones that are similar to the coal to hydrogen process, which are the coal preparation, ASU, gasifier, syngas cooling and cleaning, acid gas removal, shift and PSA as one zone and steam boiler. On top of these, there is one additional zone, which is the ammonia synthesis unit. An additional operator is required for the control room. Hence, nine process operators are required in total.

The rest of the parameters remained the same as that from the coal to hydrogen plant. These are adjusted to reflect the costs per t ammonia product. The operating cost model for ammonia production from coal is shown in Table 4.79.

Table 4.79: Operating cost model for a partial oxidation ammonia plant using black coal feedstock (Costs are expressed in 2012A$)

Plant capacity	2,000 t/day				
Plant availability	85%				
Annual actual production	620,500 t/yr				
Fixed capital investment	858 $ million				
Capital exponent, ψ ($I=\alpha Q\psi$)	0.7				
Cost year	2012 AUD$				
Operating costs				**Annual cost ($ million)**	**Cost per tonne NH_3 ($/t NH_3)**
Raw materials		Unit usage (/t NH_3)	Unit cost ($/unit)		
Black coal fuel/feedstock	t	1.50	33.1	30.88	49.76
Utilities		Unit usage (/t NH_3)	Unit cost ($/unit)		
Electricity	MWh	1.25	85.2	66.21	106.71
Cooling water	m3	149	0.08	7.14	11.51
Demineralised water	t	5.68	1.50	5.28	8.52
Waste treatment				0.12	0.19
Solid waste disposal				2.30	3.71
Other				2.85	4.59
Total variable costs				**114.78**	**184.98**
Byproducts		Unit usage (/t NH_3)	Unit cost ($/unit)		
Byproduct steam	t	2.97	25.50	-46.93	-75.64
Total byproduct costs				**-46.93**	**-75.64**
Operating labour		No.	Salary ($/yr)		
Operators/shift		9			
Shift teams		5			
Total shift operators		45	87,000	3.92	6.31
Total operating labour costs				**3.92**	**6.31**
Payroll overheads		40	% total operating labour cost	**1.57**	2.52
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.82	1.32
Maintenance labour		1		8.58	13.82
Maintenance materials		1		8.58	13.82
Consumables store			10	0.55	0.88
Plant overheads			100	5.48	8.83
Laboratory			10	0.55	0.88
Insurance		1		8.58	13.82
Property taxes		1		8.58	13.82
Total fixed costs				**47.18**	**76.04**
Total manufacturing costs				**115.03**	**185.38**
Non-manufacturing costs		(%)	Factor		
Administrative costs		4	Total production cost	5.35	**8.62**
Marketing costs		5	Total production cost	6.69	**10.78**
Research and development costs		5	Total production cost	6.69	**10.78**
General expenses				**18.73**	**30.18**
Total product cost				**133.75**	**215.56**

Table 4.80 summarises the total operating cost for the coal to ammonia plant. The waste treatment and disposal costs do not significantly affect the hydrogen cost as they make up less than 2% of the total operating costs.

Table 4.80: Total operating cost of a partial oxidation ammonia plant using black coal feedstock (Costs are expressed in 2012A$)

Capacity (t/day)		2000	
Output (t/year)		620,500	
Annualised capital costs (A$/t NH_3)		147	
Export steam revenue @ $25.5/t		Excluded	Included
Cash operating costs	Variable costs (A$/t NH_3)	185	185
	Fixed costs (A$/t NH_3)	76.0	76.0
	Other costs (A$/t NH_3)	42.5	30.2
	Total (A$/t NH_3)	304	216
Total operating costs (A$/t NH_3)		450	362

4.5.3.4. SUBSTITUTION IMPACTS FOR AMMONIA PRODUCTION

In the event of a natural gas scarcity, NH_3 produced from a LAC NH_3 plant is either substituted with NH_3 produced via black coal gasification or substituted with CSG as a fuel for the LAC NH_3 plant. The revenue from steam export and the wastewater treatment and disposal costs were included in the operating cost.

Substitution of natural gas with black coal will result in an increase in most environmental impact categories and in all economic impact categories as shown in Table 4.81. As the environmental impacts for ammonia were derived from the hydrogen case, the impacts for both cases share a similar trend. Decreases were reported for photochemical oxidation potential and associated water withdrawal categories because these were reported in greater quantities in natural gas extraction and processing than for black coal.

Full details of the calculations of the substitution indicators are shown in Appendix A.46.

Table 4.81: Substitution impact indicators for ammonia production in Australia

Option	Ammonia	
Feedstock	NG→BlC	NG→CSG
Technology	LAC→CG	LAC
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	+ 7.90E-09	- 1.14E-10
Acidification Potential (ADP)	+ 8.23E-08	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 1.52E-09	- 3.93E-09
Particulate Matter Formation (PMF)	+ 3.86E-10	- 9.29E-11
Freshwater Withdrawal (FWW)	+ 7.32E-11	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 1.44E-08
Saline Water Generation (CWG)	+ 7.08E-12	- 7.17E-13
Solid Waste Generation (SWG)	+ 2.16E-07	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+ 253.0	-
Cash operating costs	+ 60.7	- 61.6
Total operating costs	+ 313.0	- 61.6

Legend: '+' sign denotes increase in impacts, '-' sign denotes decrease in impacts, NG=Natural Gas, BlC=Black Coal, CSG=Coal Seam Gas, SMR=Steam Methane Reforming, CG=Coal Gasification
Note: Environmental impact indicators include upstream and downstream impacts.

4.6. NON-FERROUS METALS PROCESSING

4.6.1. OVERVIEW

Natural gas is used in many applications in the metals manufacturing industry to provide heat, power and steam. According to the 2013 Australian energy statistics (BREE 2013a), the iron and steel manufacturing industry consumed 28.1 PJ of natural gas, while the non-ferrous metals manufacturing industry consumed 153.7 PJ of natural gas. Metals that are categorised as non-ferrous include aluminium, copper, silver, lead, zinc, and gold.

This chapter will focus primarily on the alumina subsector in the non-ferrous metals processing sector as it is one of the major consumers of natural gas in Australia. Manufacturing Australia (2013b) considers the alumina subsector to be among the subsectors at risk during a natural gas shortage or natural gas price rise. This chapter also focuses on the nickel subsector, which is an example of natural gas being used to produce chemicals onsite such as H_2S and NH_3, as well as to generate heat, power and steam.

4.6.2. ALUMINA PRODUCTION

4.6.2.1. INTRODUCTION

Aluminium is sourced from bauxite ore, which contain economically recoverable quantities of the aluminium minerals gibbsite ($\gamma - Al(OH)_3$), boehmite ($\gamma - AlO(OH)$), and diaspore ($\alpha - AlO(OH)$). Gibbsite is the predominant aluminium mineral found in Western Australia, while some boehmite occurs in all but Western Australia deposits (Hudson et al. 2000). The processing of boehmite and diaspore require higher temperatures and alkali concentrations than gibbsite, making gibbsite a more economically attractive source of aluminium than the former two (Hudson et al. 2000).

Bauxite ore from the mine contains not only aluminium oxide (Al_2O_3), but other impurities including silica, iron oxide and titanium dioxide. The bauxite ore must first be purified in an alumina refinery to remove these impurities. The alumina product from the refinery is then smelted into aluminium metal using the Halls-Héroult process as shown in Equation 4.38.

$$2Al_2O_3 + 3C \rightarrow 4Al + 3CO_2 \qquad (\text{ Equation 4.38 })$$

IAI (2008) stated that bauxite mining “requires only a small amount of energy compared to refining of bauxite and electrolytic reduction of alumina” and quoted that only 3% of energy in bauxite mining and transport was attributed to natural gas. The smelting process is the most energy-intensive step due to the large consumption of electricity as shown in Table 4.82, but the alumina refining step consumes more thermal fuel than the other steps. This analysis will focus on the alumina refining section, as a natural gas shortage will significantly affect the process with high thermal energy consumption. There are limited substitutes for natural gas in this area than for electricity, which can be met with a variety of energy sources including renewable energy.

Table 4.82: Energy consumption of aluminium production (per t aluminium metal produced) (Sanders 2000, IAI 2008)

Operation	Thermal (GJ)	Electric (GJ)	Total (GJ)
Bauxite mining	0.2 – 2.5 [a]	<0.2 [a]	0.4 – 2.7
Alumina refining	30	1.7	31.7
Aluminium smelting	19 [b]	54.0	73.0
Aluminium product manufacture	19	6.6	25.6

[a] Based on 5.3 t bauxite per t aluminium metal produced (IAI 2007)

[b] Includes anode forming, anode baking, and the calorific value of the anodes

There are six alumina refineries currently operating in Australia: four in Western Australia (Kwinana, Pinjarra, Wagerup, and Worsley) and two in Queensland (Yarwun and Queensland Alumina Ltd). There was a seventh alumina refinery in Gove, Northern Territory which is shutting down at the time of writing in 2014, partly because it had no pipeline supply of natural gas.

4.6.2.2. THE BAYER PROCESS

The alumina refinery produces alumina or aluminium oxide from bauxite using the Bayer process. The process is described in detail by IAI (2007) and in Ullmann's Encyclopaedia of Industrial Chemistry (Hudson et al. 2000). A typical representation of the main process steps in the Bayer process (shown in bold) and relevant material flows are shown in Figure 4.36.

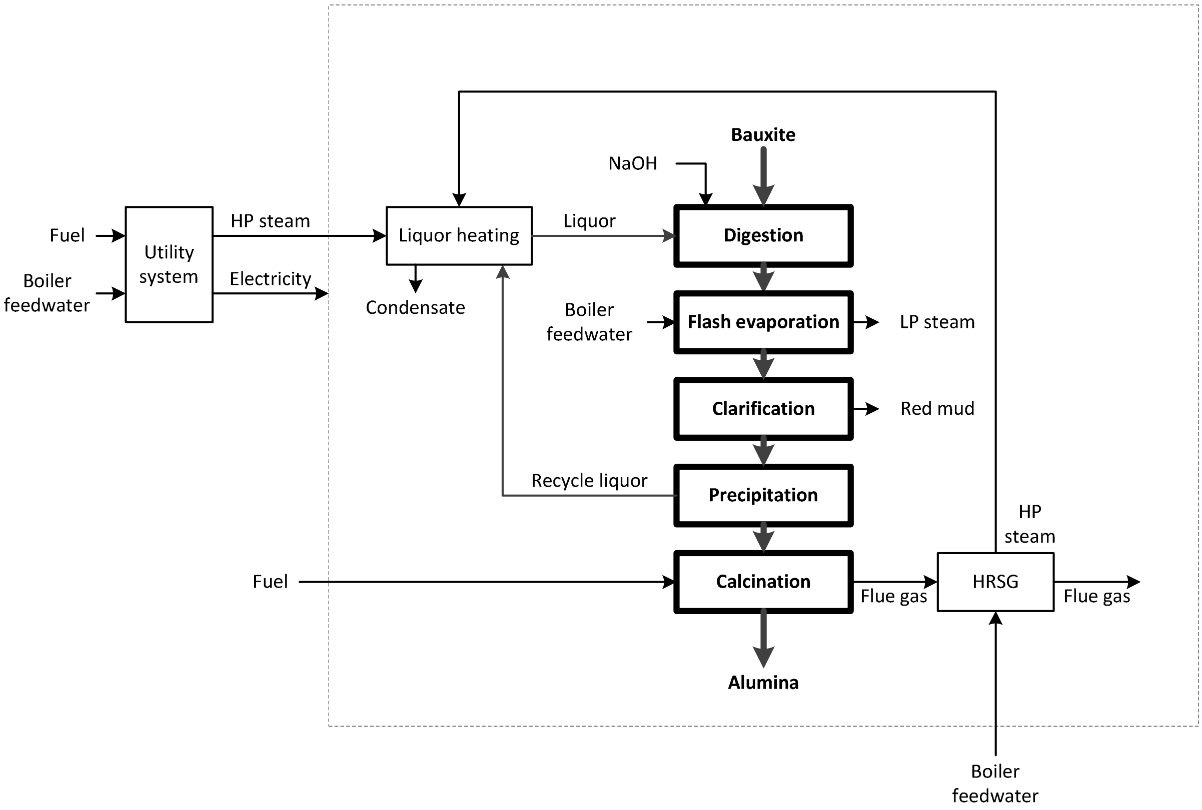


Figure 4.36: Process flow diagram of the Bayer process (shown in bold) and supporting processes and material flows

Bauxite is first ground and blended with sodium hydroxide ($NaOH$) solution. The slurry is heated and pumped to the digesters. Sodium aluminate is formed in Equation 4.39, leaving behind most of the silicon, iron, titanium and calcium oxides as insoluble components in the solid waste residue, also called red mud.

$$Al(OH)_3 + NaOH \rightarrow NaAl(OH)_4 \qquad \text{(Equation 4.39)}$$

The hot slurry is usually cooled by flash evaporation, producing steam at 100°C that is used to heat up the slurry going into the digester. The slurry then goes through a series of clarification steps to separate the solid residue from the liquor and remove impurities such as oxides of silicon and iron from the solution. Table 4.83 details the chemical constituents of Weipa bauxite residues or red mud produced by Queensland Alumina Limited (QAL). The handling and disposal of red mud is excluded from this analysis, as the focus of the analysis is only on the utility system. Substitution of fuel will have no effect on the amount on concentration of red mud produced by alumina refining.

Table 4.83: XRF analysis of red mud solid sample fractions (Picaro et al. 2002)

Chemical constituent	**%**
Fe_2O_3	36.1
Al_2O_3	22.8
SiO_2	17.0
Na_2O	7.2
TiO_2	6.7
CaO	2.2
ZnO_2	0.4
MgO	0.1
Others	7.4

The sodium aluminate is seeded with fine aluminium hydroxide ($Al(OH)_3$) crystals in precipitators to crystallise and precipitate aluminium hydroxide as shown in Equation 4.40.

$$NaAl(OH)_4 \rightarrow Al(OH)_3 + NaOH \qquad \text{(Equation 4.40)}$$

After precipitation, the slurry is sent to classification where the product is separated according to crystal sizes. The finer crystals are recycled to the precipitation process as seed, providing nucleation sites for precipitation to occur. Spent liquor from the precipitation stage is recycled back to the digesters. The coarse product is washed to remove excess NaOH and is sent to the calciners.

The crystals are heated in the calcination stage to remove mechanically and chemically bound water from the particle surfaces, leaving alumina or aluminium oxide (Al_2O_3). The calcination reaction is shown in Equation 4.41.

$$2Al(OH)_3 \rightarrow Al_2O_3 + 3H_2O \qquad \text{(Equation 4.41)}$$

4.6.2.1. ALUMINA REFINERY UTILITY REQUIREMENTS

In the Bayer process, both the digestion stage and the calcination stage require heating. The digestion stage is performed at elevated temperatures between 110 – 260°C. The specific temperature is determined by the type of bauxite ore. The digestion heat is assumed to be provided by high pressure steam at 315°C and 10,000 kPa. The calcination stage is performed in either a rotary or a fluidised bed kilns at around 1100°C. The fluidised bed or stationary kiln has lower capital, maintenance, fuel and labour costs than the rotary kiln (Hudson et al. 2000). The heating in the calcination stage is done by passing hot gas passing through the alumina. The high calcination temperature and the limitation on impurities in the final alumina product add a constraint on the type of heating fuel used. Hudson et al. (2000) stated that the fuel must be "free of impurities that can contaminate the alumina". Natural gas is the ideal choice for the fuel, as it has undergone upstream processing to remove impurities such as sulphur and it produces minimal particulates during combustion. The alumina refinery used in this study is based on the Pinjarra refinery, which is one of the largest and cost efficient alumina refineries in the world. The refinery has a production capacity of 4.2 million t alumina/yr, which is equivalent to 480 t/hr. Electricity and steam requirements were adapted from LCA data reported by Griffing & Overcash (2010). The calcination energy requirement is based on a stationary kiln. The derivation of these values is found in Appendix A.47.

The utility requirements of the alumina refinery are summarised in Table 4.84. The electricity requirement is 1.5 times the reported figure in Table 4.84. In Griffing & Overcash (2010), the majority of the electricity requirement is attributed to the crystalliser mixers, which consume 0.56 MWh/t alumina. The remaining electricity is used in the conveyors, pumps, crushers, digestor mixer, classifier, drum filters and vacuum.

Table 4.84: Alumina refinery utility requirements

Material flows	Value	Units
Alumina production rate	480	t/hr
Electricity requirement	374	MW
	0.78	MWh/t alumina
HP steam requirement @ 311°C, 10,000 kPa	1,530	t/hr
	3.18	t/t alumina
Calcination energy requirement	1,488	GJ/hr
	3.1	GJ/t alumina

4.6.2.2. NATURAL GAS/CSG COGENERATION SYSTEM

Figure 4.37 shows the natural gas cogeneration plant that meets the steam and electricity demands of a typical alumina refinery. The cogeneration plant consists of a gas turbine to produce electricity with a heat recovery steam generator (HRSG) to produce steam from the hot flue gas exiting the gas turbine. By fully meeting the steam demands, the combined heat and power utility configuration will produce excess electricity which is exported to the grid. Natural gas is used as the calciner fuel.

4.6.2.2.1. Material flows

The steam requirement of the alumina refinery is partially met by the steam recovered from the hot flue gas exiting the calciner. The calciner was assumed to remove free and bounded water in the alumina at 85% efficiency. The water mixes with the hot gas and enters a heat recovery steam generator (HRSG) which produces the maximum amount of steam at 85% efficiency. A HYSYS model of the natural gas-fired calciner can be found in Appendix A.48.

The remaining steam demand is met by the cogeneration plant, assuming an 85% energy recovery for steam generation in the HRSG. The amount of electricity produced from natural gas in the cogeneration unit is 0.1 MWh/GJ or 0.36 GJ electricity per GJ natural gas, which is equivalent to a net electrical efficiency of 36% HHV. The electricity produced will meet the electricity requirement of the alumina refinery and the remainder is exported to the grid. A HYSYS model of the cogeneration system is located in Appendix A.49.

Table 4.85 summarises the material flows for the natural gas/CSG utility system in the alumina refinery. The workings for Table 4.85 can be found in Appendix A.50.

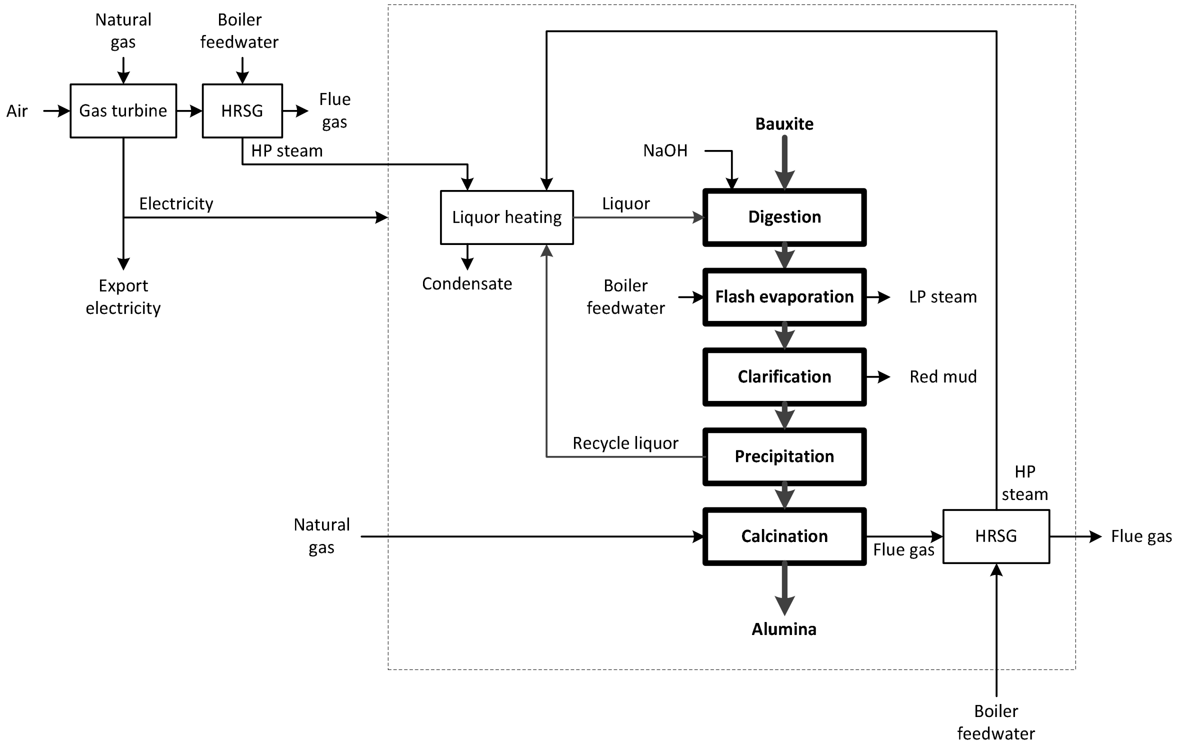


Figure 4.37: Natural gas utility system for an alumina refinery.
Note: The dotted box represents the boundary of the alumina refinery. Any units within the boundary is outside the scope of this study.

Table 4.85: Material flows for a natural gas/CSG utility system in an alumina refinery

Material flows	Value	Units
Gas turbine/HRSG		
Natural gas to gas turbine @ 51.34 GJ/t NG HHV	111	t/hr
	0.232	t/t alumina
Electricity generated	522	MW
	1.09	MWh/t alumina
HP steam generated	952	t/hr
	1.99	t/t alumina
Calciner		
Natural gas to calciners @ 51.34 GJ/t NG HHV	34	t/hr
	0.0710	t/t alumina
HP steam generated	574	t/hr
	1.20	t/t alumina
Feedstock requirement		
Total natural gas @ 51.34 GJ/t NG HHV	145	t/day
	0.303	t/t alumina
Electricity export		
Total electricity exported (MWh)	125	MW
	0.26	MWh/t alumina

The material flows for the cogeneration section is based on a CCGT power plant, but with the steam turbine component removed. This will lower the net output of the plant while maintaining the same fuel consumption, thus lowering the efficiency of the plant. The cogeneration plant itself requires minimal cooling water, similar to an OCGT plant. The cogeneration plant in this study is sized specifically to meet the steam requirements of the alumina refinery. Energy is used to generate steam and all of the energy is consumed by the alumina plant, thus the need for cooling water in the cogeneration plant is eliminated. The alumina refinery itself was reported to have a cooling water requirement of 5,228 MJ/t alumina (Griffing & Overcash 2010), which requires 113.7 t cooling water/t alumina based on a specific heat capacity of 4.18 kJ/kg.°C and a cooling water range of 11°C. However, this is outside the boundary of the utility system and is therefore not considered. Steam blowdown was assumed to be 5% of total steam flow. A summary of the material flow data for the alumina plant natural gas/CSG utility system is shown in Table 4.86.

Table 4.86: Material flow data for an alumina refinery natural gas/CSG utility system

Inventory data	Units	Combined heat and power	Calciner (natural gas as fuel)	Electricity material flows [a]	Total	Category
Input						
Natural gas	t/t alumina	2.32E-01	7.10E-02	-4.24E-03	2.99E-01	Fuel/Feedstock
Black coal	t/t alumina	0	0	-6.60E-02	-6.60E-02	
Cooling water makeup	t/t alumina	0	0	-3.71E-01	-3.71E-01	Freshwater Withdrawal
Boiler feedwater makeup	t/t alumina	9.93E-02	5.92E-02	-2.07E-02	1.38E-01	Freshwater Withdrawal
Output						
Cooling water blowdown	t/t alumina	0	0	-4.03E-02	-4.03E-02	Saline Water Generation
Steam blowdown	t/t alumina	9.93E-02	5.92E-02	-2.07E-02	1.38E-01	Saline Water Generation
CO_2	t/t alumina	6.15E-01	2.20E-01	-1.53E-01	6.82E-01	Global Warming Potential
CH_4	t/t alumina	5.71E-05	2.04E-05	-3.34E-06	7.42E-05	Global Warming Potential
N_2O	t/t alumina	1.17E-06	4.15E-07	-1.34E-07	1.45E-06	Global Warming Potential
VOC	t/t alumina	7.28E-06	9.95E-06	-1.06E-06	1.62E-05	Photochemical Oxidation Potential
CO	t/t alumina	3.49E-04	1.52E-04	-3.39E-04	1.62E-04	Photochemical Oxidation Potential
NO_x	t/t alumina	8.68E-04	5.77E-05	-2.29E-05	9.03E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t alumina	5.67E-06	1.99E-06	-1.04E-07	7.56E-06	Acidification Potential
PM_{10}	t/t alumina	3.37E-05	1.34E-05	-2.38E-05	2.32E-05	Particulate Matter Formation
Ash	t/t alumina	0	0	-1.40E-02	-1.40E-02	Solid Waste Generation Potential

[a] Electricity assumed to be generated using Australian reference grid electricity fuel mix (see Appendix A.20)

4.6.2.2.2. Capital cost

The capital cost of the natural gas/CSG utility system was assumed to be similar to a CCGT power plant. Bedilion et al. (2009) published the cost breakdown of a net 711 MW CCGT power station in Australia which consisted of two gas turbines and a steam turbine. The efficiency of the CCGT plant is 49.5% HHV. The procedure to adapt the capital cost for a cogeneration unit with a single gas turbine and no steam turbines is described in detail in Appendix A.51.

Table 4.87 summarises the adjusted capital cost breakdown of the natural gas/CSG utility system.

Table 4.87: Equipment cost breakdown for the alumina refinery cogeneration plant (Costs are expressed in 2012A$)

Equipment items	**Cost (2012A$million)**
Feedwater & miscellaneous systems	33.5
Combustion turbine & accessories	225.2
HRSG, ducting and stack	114.6
Steam turbine generator (including accessories)	-
Cooling water system	-
Accessory electric plant	78.4
Instrumentation & controls	29.3
Improvements to site	26.3
Buildings and structures	27.8
Direct plant cost	**535.0**
Engineering and project management [a]	133.7
Total plant cost	**668.7**

[a] Assumed to be25% of direct plant cost.

4.6.2.2.3. Operating cost

Table 4.88 and Table 4.89 show the operating cost model for the utility system using natural gas and CSG in a 480 t/hr alumina plant with the inclusion of the revenue generated from export electricity.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the natural gas utility system, there are two process zones, which are the gas turbine and the steam generation system. An additional operator is required for the control room. Hence, three process operators are required in total.

Table 4.88: Operating cost model for a natural gas based utility system in an alumina refinery (Costs are expressed in 2012A$)

Plant capacity	11,500	t alumina/day
Plant availability	85%	
Annual actual production	3,570,000	t alumina/yr
Fixed capital investment	669	$ million
Capital exponent,ψ (I=αQψ)	0.7	
Cost year	2012	Australian dollars (A$)

Operating costs					**Annual cost ($ million)**	**Cost per tonne ($/t alumina)**
Raw materials		Unit usage (/t alumina)	Unit cost ($/unit)			
Natural gas fuel	t	0.303	179		193.45	54.19
Utilities		Unit usage (/t alumina)	Unit cost ($/unit)			
Cooling water	m3	0	0.0770		-	-
Demineralised water	t	0.159	1.50		0.85	0.24
Total variable costs					**194.31**	**54.43**
Byproducts		Unit usage (/t alumina)	Unit cost ($/unit)			
Export electricity	MWh	0.260	70.00		-64.9	-18.18
Total byproduct costs					**-64.9**	**-18.18**
Operating labour		No.	Salary ($/yr)			
Operators/shift		3				
Shift teams		5				
Total shift operators		15		82,000	1.23	0.34
Total operating labour costs					**1.23**	**0.34**
Payroll overheads		40	% total operating labour cost		0.49	0.14
		% fixed capital	**% operating labour + payroll overheads**			
Supervision			15		0.26	0.07
Maintenance labour		1			6.69	1.87
Maintenance materials		1			6.69	1.87
Consumables store			10		0.17	0.05
Plant overheads			100		1.72	0.48
Laboratory			10		0.17	0.05
Insurance		1			6.69	1.87
Property taxes		1			6.69	1.87
Total fixed costs					**30.80**	**8.63**
Total manufacturing costs					**160.21**	**44.88**
Non-manufacturing costs		(%)	Factor			
Administrative costs		2	Total production cost		4.74	1.33
Marketing costs		2	Total production cost		4.74	1.33
Research and development costs		1	Total production cost		2.37	0.66
General expenses					**11.85**	**3.32**
Total product cost					**172.05**	**48.19**

Table 4.89: Operating cost model for a CSG based utility system in an alumina refinery (Costs are expressed in 2012A$)

Plant capacity	11,500	t alumina/day	
Plant availability	85%		
Annual actual production	3,570,000	t alumina/yr	
Fixed capital investment	669	$ million	(for utility system only)
Capital exponent,ψ (I=αQψ)	0.7		
Cost year	2012	Australian dollars (A$)	

Operating costs				**Annual cost ($ million)**	**Cost per tonne ($/t alumina)**
Raw materials		Unit usage (/t alumina)	Unit cost ($/unit)		
Coal seam gas fuel	t	0.303	138	149.63	41.91
Utilities		Unit usage (/t alumina)	Unit cost ($/unit)		
Cooling water	m3	0	0.0770	-	-
Demineralised water	t	0.159	1.50	0.85	0.24
Total variable costs				**150.49**	**42.15**
Byproducts		Unit usage (/t alumina)	Unit cost ($/unit)		
Export electricity	MWh	0.260	70.00	-64.9	-18.18
Total byproduct costs				**-64.9**	**-18.18**
Operating labour		No.	Salary ($/yr)		
Operators/shift		3			
Shift teams		5			
Total shift operators		15	82,000	1.23	0.34
Total operating labour costs				**1.23**	**0.34**
Payroll overheads		40	% total operating labour cost	0.49	0.14
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.26	0.07
Maintenance labour		1		6.69	1.87
Maintenance materials		1		6.69	1.87
Consumables store			10	0.17	0.05
Plant overheads			100	1.72	0.48
Laboratory			10	0.17	0.05
Insurance		1		6.69	1.87
Property taxes		1		6.69	1.87
Total fixed costs				**30.80**	**8.63**
Total manufacturing costs				**116.39**	**32.60**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	3.82	1.07
Marketing costs		2	Total production cost	3.82	1.07
Research and development costs		1	Total production cost	1.91	0.53
General expenses				**9.54**	**2.67**
Total product cost				**125.93**	**35.27**

Table 4.90 summarises the total operating cost for the operation of the natural gas/CSG utility system in the alumina refinery, which is inclusive of annualised capital costs and cash operating costs. The export electricity is able to offset between 20 to 24% of the total operating cost. Thus, exporting the excess electricity to the grid makes the natural gas/CSG fuelled utility system more economically attractive.

Table 4.90: Total operating costs for natural gas/CSG utility systems in a 4,400 t/day alumina refinery (Costs are expressed in 2012A$)

Capacity (t/day alumina)		4,400			
Output (t/year alumina)		1,365,100			
Annualised capital costs (A$/t alumina)		19.9			
Export electricity revenue @ $70/MWh		Excluded		Included	
Feedstock type		NG	CSG	NG	CSG
Cash operating costs	Variable costs (A$/t alumina)	54.4	42.2	36.3	24.0
	Fixed costs (A$/t alumina)	8.63	8.63	8.63	8.63
	Other costs (A$/t alumina)	3.32	2.67	3.32	2.67
	Total (A$/t alumina)	66.4	53.5	48.2	35.3
Total operating costs (A$/t alumina)		86.2	73.3	68.1	55.1

4.6.2.3. BLACK COAL UTILITY SYSTEM

A centralized utility system produces electricity, steam and synthesis gas fuel for the calciner as shown in Figure 4.38. This option is based on an IGCC power station which was designed to fully meet the alumina refinery's steam demand. HP steam is generated using recovered heat from both the gas turbine flue gas and the calciner flue gas. In producing the required amount of heat, the steam turbine generates more power than is required by the alumina refinery, and the excess power is exported to the grid. The gasifier was sized to produce sufficient syngas fuel to meet the combined requirements for both the gas turbine power output and for the calciner fuel demand.

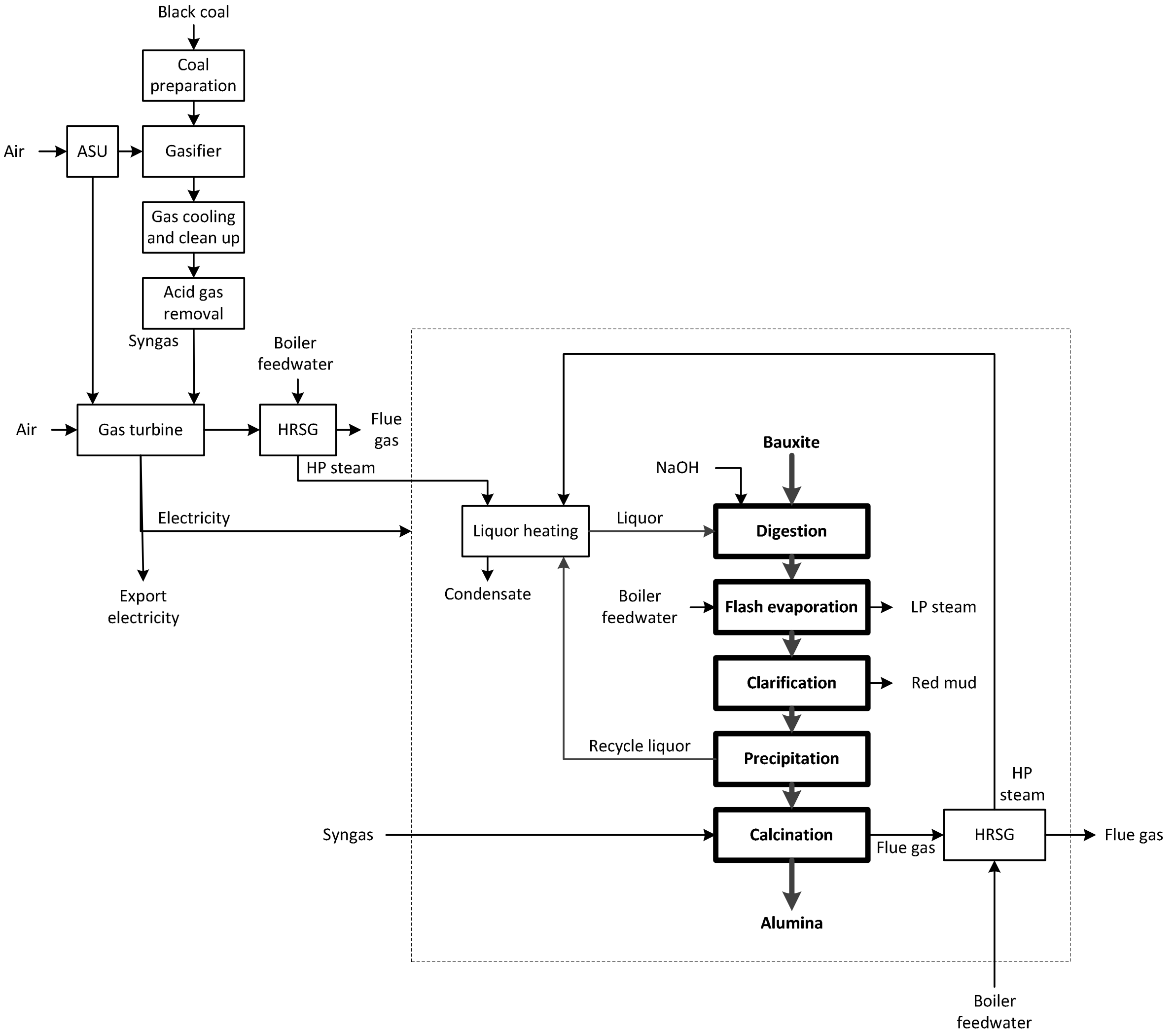


Figure 4.38: Integrated black coal utility system for an alumina refinery.
Note: The dotted box represents the boundary of the alumina refinery. Any units within the boundary is outside the scope of this study.

4.6.2.3.1. Material flows

The material flow data for the utility plant were calculated based on an IGCC plant from NETL (2010a). The steam turbine component is removed, causing the net electrical efficiency to drop as the fuel consumption is kept constant.

HYSYS models are created for the black coal-based utility system (see Appendix A.52) and the syngas-fired calciner (see Appendix A.53). This provides steam generation and electricity generation data. The full calculations are found in Appendix A.54. The summary of the material flows can be found in Table 4.91.

Table 4.91: Material flows for the integrated black coal utility system in alumina refinery

Material flows	Value	Units
Gasifier		
Coal to gasifier @ 24.4 GJ/t NG HHV	427	t/hr
	0.89	t/t alumina
Syngas produced	741	t/hr
	1.55	t/t alumina
Electricity for auxiliary equipment	191	MW
	0.40	MWh/t alumina
Gas turbine/HRSG		
Syngas to gas turbine	581	t/hr
	1.21	t/t alumina
Electricity generated	704	MW
	1.47	MWh/t alumina
HP steam generated	1,150	t/hr
	2.39	t/t alumina
Calciner		
Syngas to calciner	160	t/hr
	0.33	t/t alumina
HP steam generated	381	t/hr
	0.795	t/t alumina
Electricity		
Electricity exported	139	MW
	0.29	MWh/t alumina

Emission data were based on IGCC data in Table 4.38 and were adjusted due to the change in the net electrical efficiency. The emissions from calciners fuelled by syngas were assumed to be similar to the emissions from the gas turbine running on syngas.

The cooling water requirement of the alumina refinery is identical to the natural gas case. Steam blowdown was assumed to be 5% of total steam flow.

The material flows are summarised in Table 4.92.

Table 4.92: Material flow data of an alumina refinery integrated black coal utility system

Inventory data	Units	IGCC	Electricity emissions [a]	Total	Category
Input					
Black coal	t/t alumina	8.90E-01	-1.06E-01	7.84E-01	Fuel/Feedstock
Cooling water makeup	t/t alumina	0	-5.52E-01	-5.52E-01	Freshwater Withdrawal
Demineralised water	t/t alumina	1.59E-01	-2.91E-02	1.30E-01	Freshwater Withdrawal
Output					
Cooling water blowdown	t/t alumina	0	-5.81E-02	-5.81E-02	Saline Water Generation
Steam blowdown	t/t alumina	1.59E-01	-2.91E-02	1.30E-01	Saline Water Generation
CO_2	t/t alumina	1.86E+00	-2.27E-01	1.63E+00	Global Warming Potential
CH_4	t/t alumina	7.76E-06	-3.69E-06	4.07E-06	Global Warming Potential
N_2O	t/t alumina	8.94E-09	-1.66E-06	-1.66E-06	Global Warming Potential
VOC	t/t alumina	5.49E-08	-1.93E-09	5.29E-08	Photochemical Oxidation Potential
CO	t/t alumina	9.82E-07	-2.64E-05	-2.55E-05	Photochemical Oxidation Potential
NO_x	t/t alumina	6.01E-04	-5.18E-04	8.33E-05	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t alumina	2.41E-05	-1.37E-09	2.41E-05	Acidification Potential
PM_{10}	t/t alumina	7.84E-05	-3.71E-05	4.13E-05	Particulate Matter Formation
Ash	t/t alumina	1.74E-01	-2.24E-02	1.51E-01	Solid Waste Generation

[a] Electicity assumed to be generated from PCST power station (see Table 4.36)

4.6.2.3.2. Capital cost

The capital costs of the cogeneration section, shown in Table 4.93, were calculated based on an IGCC power plant adopted from Bedilion et al. (2009) with the steam turbine component removed. The procedure to calculate the black coal-based utility system for the alumina refinery is covered in detail in Appendix A.55.

Table 4.93: Equipment cost breakdown for a black coal-based alumina refinery utility system (Costs are expressed in 2012A$)

Equipment items	**Cost (2012A$million)**
Coal and fluxant/sorbent handling	123.9
Coal and fluxant/sorbent preparation & feed	516.8
Feedwater & miscellaneous systems	56.5
Gasifier, ASU & accessories	1,642.0
Gas cleanup & piping/flue gas cleanup	236.0
Combustion turbine & accessories	244.3
HRSG, ducting and stack	188.2
Steam turbine generator (including accessories)	-
Cooling water system	-
Ash/spent sorbent handling	159.8
Accessory electric plant	190.4
Instrumentation & controls	56.7
Improvements to site	56.4
Buildings and structures	56.2
Direct plant cost	**3,527.0**
Engineering and project management [a]	881.7
Total plant cost	**4,408.7**

[a] Assumed to be 25% of direct plant cost.

4.6.2.3.3. Operating cost

Table 4.94 shows the operating cost model for the black coal utility system in a 4,400 t/day alumina plant with the inclusion of the revenue generated from export electricity.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the coal utility system, there are seven process zones, which are the coal preparation, ASU, gasifier, syngas cooling and cleaning, acid gas removal, gas turbine and steam generation system. An additional operator is required for the control room. Hence, eight process operators are required in total.

Table 4.94: Operating cost model for a black coal based utility system in an alumina refinery (Costs are expressed in 2012A$)

Plant capacity	11,500	t alumina/day			
Plant availability	85%				
Annual actual production	3,570,000	t alumina/yr			
Fixed capital investment	4,409	$ million			
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	Australian dollars (A$)			
Operating costs				**Annual cost ($ million)**	**Cost per tonne ($/t alumina)**
Raw materials		Unit usage (/t alumina)	Unit cost ($/unit)		
Black coal fuel	t	0.890	33.10	105.25	29.48
Utilities		Unit usage (/t alumina)	Unit cost ($/unit)		
Cooling water	m3	0	0.08	-	-
Demineralised water	t	0.159	1.50	0.85	0.24
Total variable costs				**106.10**	**29.72**
Byproducts		Unit usage (/t alumina)	Unit cost ($/unit)		
Export electricity	MWh	0.291	70.00	-72.65	-20.35
Total byproduct costs				**-72.65**	**-20.35**
Operating labour		No.	Salary ($/yr)		
Operators/shift		8			
Shift teams		5			
Total shift operators		40	82000	3.28	0.92
Total operating labour costs				**3.28**	**0.92**
Payroll overheads		40	% total operating labour cost	1.31	0.37
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.69	0.19
Maintenance labour		1		44.09	12.35
Maintenance materials		1		44.09	12.35
Consumables store			10	0.46	0.13
Plant overheads			100	4.59	1.29
Laboratory			10	0.46	0.13
Insurance		1		44.09	12.35
Property taxes		1		44.09	12.35
Total fixed costs				**187.14**	**52.42**
Total manufacturing costs				**220.59**	**61.79**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	6.17	1.73
Marketing costs		2	Total production cost	6.17	1.73
Research and development costs		1	Total production cost	3.09	0.86
General expenses				**15.43**	**4.32**
Total product cost				**236.02**	**66.11**

Table 4.95 summarises the total operating cost for the black coal utility system in the alumina refinery, which consists of annualised capital costs and cash operating costs.

Table 4.95: Total operating costs for black coal utility systems in a 4,400 t/day alumina refinery (Costs are expressed in 2012A$)

Capacity (t/day alumina)		4,400	
Output (t/year alumina)		3,570,000	
Annualised capital costs (A$/t alumina)		131	
Export electricity revenue @ $70/MWh		Excluded	Included
Cash operating costs	Variable costs (A$/t alumina)	29.7	9.37
	Fixed costs (A$/t alumina)	52.4	52.4
	Other costs (A$/t alumina)	4.32	4.32
	Total (A$/t alumina)	86.5	66.1
Total operating costs (A$/t alumina)		217	197

4.6.2.4. SUBSTITUTION IMPACTS FOR ALUMINA REFINERY UTILITY SYSTEM

Table 4.96 summarises the environmental and economic impacts that result from the substitution of a natural gas utility system in an alumina refinery with a black coal or a CSG utility system. For the operating costs of all feedstock cases, the revenue from electricity export was included.

For alumina refining, the environmental impacts due to the offset of emissions by the export of electricity have been taken into account for the natural gas, black coal and CSG cases. The substitution impact indicators for natural gas with black coal in Table 4.96 were shown to have negative values for most of the environmental impact categories. This was due to the effect of the offset of emissions by export electricity and that the black coal case recorded a higher electricity export figure than the natural gas case. Regardless, the greenhouse gas emissions, particulates and solid waste generation for the black coal case were significantly high enough to produce positive substitution impact indicators. For economic impacts, the significant increase in total operating costs is also largely due to the high capital costs of gasification systems, resulting in a large increase in annualised capital costs.

Full details of the calculations of the substitution indicators are shown in Appendix A.56.

Table 4.96: Substitution impact indicators for alumina refinery utility systems in Australia

Option	Alumina refinery utility system	
Feedstock	NG→BlC	NG→CSG
Technology	Cogen→IGCC	Cogen
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	+ 5.62E-09	- 1.14E-10
Acidification Potential (ADP)	- 1.44E-09	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 3.46E-09	- 3.93E-09
Particulate Matter Formation (PMF)	+ 2.88E-11	- 9.29E-11
Freshwater Withdrawal (FWW)	- 7.20E-12	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 1.44E-08
Saline Water Generation (CWG)	- 1.72E-12	- 7.17E-13
Solid Waste Generation (SWG)	+ 1.80E-07	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+ 438.0	-
Cash operating costs	+ 59.9	- 43.2
Total operating costs	+ 498.0	- 43.2

Legend: '+' sign denotes increase in impacts, '-' sign denotes decrease in impacts, NG=Natural Gas, BlC=Black Coal, CSG=Coal Seam Gas, Cogen=Cogeneration, IGCC=Integrated Gasification and Combined Cycle

Note: Environmental impact indicators include upstream and downstream impacts.

4.6.3. NICKEL PRODUCTION

4.6.3.1. INTRODUCTION

Nickel exists in nature as sulphide ores or laterite ores, each possessing different mineral compositions as shown in Table 4.97. Laterite ores can be categorised as saprolite ores (>1.7% Ni) or limonite ores (<1.5% Ni). Nickel can be recovered from sulphide ores through a single route that involves flash furnace smelting and Sherritt-Gordon refining. Nickel is recovered from saprolite ores through a pyro-metallurgical smelting route while limonite ores require a hydro-metallurgical route (ammonia leach or acid pressure leaching and electrowinning).

This analysis will focus on sulphide ores. Nickel from sulphide deposits is easier and cheaper to mine, while the production of nickel from oxide ores consumes two to three times as much energy as the processing of sulphide ores (Kerfoot 2000). Hence, it is economically attractive to extract nickel from sulphide ores in preference to laterite ores.

Table 4.97: Composition of different nickel-bearing ores (Kerfoot 2000)

Element	Sulphide ore (%)	Laterite (oxide) ore	
		Limonite ore (<1.5% Ni) (%)	Saprolite ore (>1.7% Ni) (%)
Ni	0.2 – 4	0.8 – 1.5	1.8 – 3
Fe	10 – 30	40 – 50	10 – 25
S	5 – 20	-	-
Cu	0.2 – 2	-	-
Co	-	0.1 – 02	0.02 – 0.1
Cr_2O_3	-	2 – 5	1 – 2
MgO	-	0.5 – 5	15 – 35

4.6.3.2. NICKEL PROCESSING IN AUSTRALIA

Nickel mining and processing predominantly occurs in Western Australia. The major sulphide nickel mines are owned by BHP Billiton’s Nickel West operations which include the Mt. Keith mine and concentrator, Leinster mine and concentrator, Kambalda concentrator, Kalgoorlie nickel smelter and Kwinana refinery. The Kargoorlie smelter uses the Outotec-type flash smelting shown in Figure 4.39.

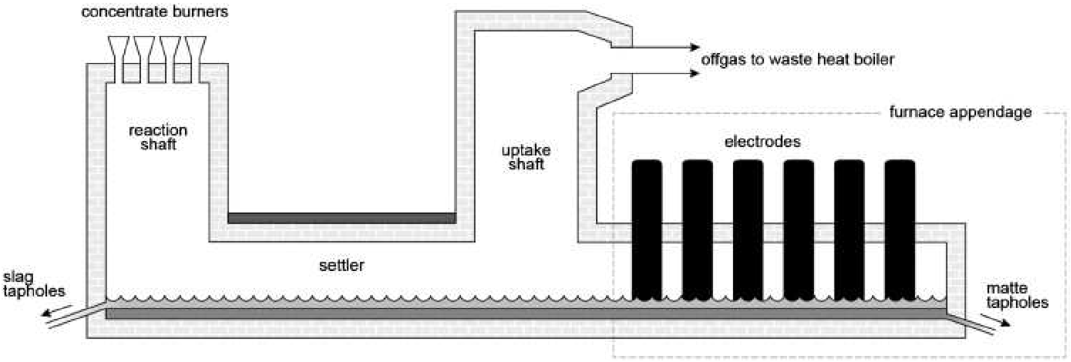


Figure 4.39:Outotec-type flash furnace with electrically heated appendage used in Kargoorlie, Australia (CM Solutions (Pty) Ltd n.d.)

Crundwell et al. (2011) explains the flash smelting process in detail. Flash smelting combines the roasting and melting processes together, resulting in less electricity and fuel consumption due to the energy generated by the roasting reactions shown in Equation 4.42 and Equation 4.43.

$$Ni_{4.5}Fe_{4.5}S_8(s)+5.75O_2(g)\xrightarrow{1300°C}4.5NiS(l)+4.5FeO(l)+3.5SO_2(g) \quad \Delta H_R=-1200\,kJ/mol\,Ni_{4.5}Fe_{4.5}S_8 \qquad (\text{Equation 4.42})$$

$$Fe_8S_9(s)+13O_2(g)\xrightarrow{1300°C}8FeO(l)+9SO_2(g) \quad \Delta H_R=-2500\,kJ/mol\,Fe_8S_9 \qquad (\text{Equation 4.43})$$

Flash smelting avoids the production of weak sulphur dioxide gas, and continuous blowing of oxygen is required for the process. The process produces a molten sulphide matte rich in nickel, a molten slag lean in nickel and hot, and dust laden gas containing SO_2. It is the dominant method of smelting nickel sulphide, despite the large loss of nickel and other metals to slag. According to Crundwell et al. (2011), the Kargoorlie smelter is able to process 1.2 million tonnes of nickel concentrate with 15% Ni and produce 100,000 t nickel matte/yr with 47% Ni. The process also consumes 1 t O_2, 0.01 m^3 fuel oil and 0.04 MWh electrical input for every t Ni matte produced. Due to the exothermic smelting reaction, no natural gas fuel is required for continuous operation.

The nickel matte is then transported to the Kwinana refinery where the Sherritt-Gordon process is used to produce nickel metal as shown in Figure 4.40. Apart from nickel, by-products such as copper sulphide, nickel/cobalt sulphide and ammonium sulphate are produced together from the process. These are transported to other plants for further processing to obtain copper and cobalt metals.

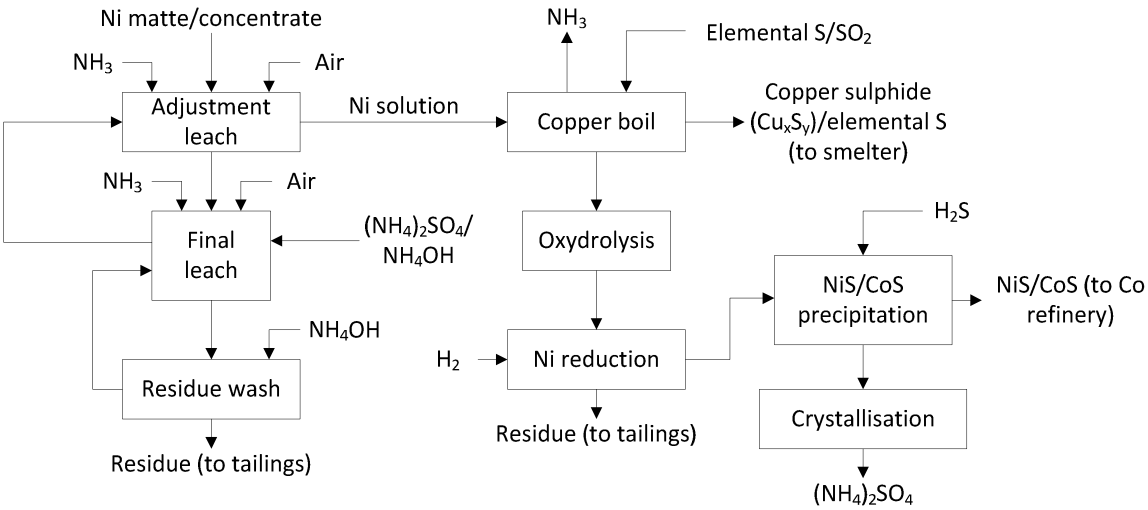


Figure 4.40: Flowsheet diagram of the general Sherritt ammonia pressure leach process (Kerfoot 2000)

The Sherritt-Gordon process utilises the following chemicals which are derived from natural gas:

- H_2S is used for precipitation of residual nickel and cobalt from process liquor.
- NH_3 used in nickel matte leaching and copper boiling.
- H_2 used to recover the nickel from the matte by chemical reduction

DEC (2011) provided details regarding the Sherritt-Gordon process in the Kwinana refinery. The matte is first ground in ball mills, and then it goes through three stages of leaching where it is reacted with air and ammonia at 85°C and 900 kPa. Matte feed is recycled by enriching it and then directing it back to the first stage leach to repeat the process and minimise waste. In the copper boil stage, pure sulphur is added to create a chemical reaction to allow removal of copper as copper sulphide. Ammonia vapour is recovered and recycled, and sulphuric acid is injected in conjunction with steam to remove any ammonia still present. Water is also evaporated leaving a liquid nickel concentrate or liquor. H_2S is used for the precipitation of residual nickel and cobalt from process liquor. In the oxydrolysis stage, the liquor is purified at 245°C and 4000 kPa to remove any residual sulphur. The nickel reduction stage is where hydrogen is introduced at 200°C and 2800 kPa to separate nickel particles. The nickel particles gradually become larger and are left to settle and be removed. Hydrogen sulphide is added to the remaining process liquor to precipitate residual nickel and cobalt.

According to the DEC (2011), the nickel refinery produced its own H_2S and H_2 gas onsite. H_2S was produced in an exothermic reaction of molten elemental sulphur and hydrogen gas in a reactor vessel at 450°C and 650 kPa(g) according to the exothermic chemical reaction shown in Equation 4.44.

$$S(l)+H_2(g)\rightarrow H_2S(g) \qquad (\text{Equation 4.44})$$

H_2 was produced using steam reforming technology, where natural gas and steam react in a gas-fired steam reforming furnace at an elevated temperature of 850°C and pressure of 2700 kPa over an activated catalyst. The on-site hydrogen was supplied to the nickel reduction autoclaves, nickel sintering furnaces and the H_2S plant.

Natural gas was used onsite to generate steam for the nickel refining process. No natural gas usage to generate power was reported. Ammonia was not generated onsite, as the Kwinana Nickel refinery is able to take advantage of the industrial synergies in the Kwinana Industrial Park by sourcing the ammonia from the nearby Westfarmers CSBP Ltd ammonia plant.

Using this information, we can construct a model of the utility system suitable for a nickel refinery needs. It must be able to produce steam, electricity and the chemicals H_2S, NH_3 and H_2.

4.6.3.3. NICKEL REFINERY UTILITY REQUIREMENTS

Norgate and Rankin (2000) from CSIRO Australia published LCI data for nickel production from the mining stage to the refinery stage. The processes covered were beneficiation, flash furnace smelting and Sherritt-Gordon refining of nickel from sulphide ores. Table 4.98 shows that natural gas is only consumed in the refinery stage for the entire production stage. Fossil fuels are not significant inputs in the mining and concentrator stage, and the smelter stage becomes self-sufficient due to the exothermic oxidizing reactions of iron and sulphur in the concentrate feed.

Table 4.98: LCI for nickel production from sulphide ores (Norgate & Rankin 2000)

Process	Inventory	Values	Units
Mine	Diesel fuel	0.002	t/t ore
	Electricity	0.013	MWh/t ore
Concentrator	Electricity	0.035	MWh/t ore
Smelter	Oil	0.06	t/t concentrate
	Coal	0.065	t/t concentrate
	Oxygen	0.148	t/t concentrate
	Electricity	0 [a]	MWh/t concentrate
Refinery	Ammonia	0.637	t/t Ni
	Hydrogen	0.070	t/t Ni
	Natural gas	0.370 [b]	t/t Ni
	Electricity	2.9	MWh/t Ni

[a] Smelter assumed to be self-sufficient in power

[b] Includes consumption for steam generation

DEC (2011) provided throughput rates of selected processes from the Kwinana Nickel Refinery, which are summarised in Table 4.99. Ammonia and electricity consumption were not reported in the literature. The hydrogen usage was consistent with that from Table 4.98, while the natural gas usage for the Kwinana Nickel Refinery was higher than that reported in Table 4.98.

Table 4.99: Nominated throughput rates of processes in the Kwinana Nickel Refinery

Material flows	Values	Units
Nickel (t)	205.5	t/day
Copper sulphide (t)	32.9	t/day
	0.16	t/t nickel
Nickel/cobalt sulphide (t)	13.7	t/day
	0.07	t/t nickel
H_2 (t)	12-16	t/day
	0.06-0.08	t/t nickel
H_2S (t)	4.4	t/day
	0.02	t/t nickel
Natural gas fuel (t)	120	t/day
	0.58	t/t nickel

For the nickel refinery analysis, a capacity was 75,000 t nickel/yr or 8.56 t nickel/hr was chosen (DEC 2011). The values for H_2, NH_3 and electricity requirements were adopted from the LCI data in Table 4.98. The high pressure (HP) steam properties were assumed to be the same as in Section 4.6.2 for the alumina refinery. It was assumed that the nickel refinery will generate its own ammonia onsite, hence requiring additional hydrogen from the hydrogen plant. Table 4.100 summarises the material requirements for the nickel refinery. Materials such as sulphur requirement for H_2S production and H_2 required for NH_3 production are calculated using material balances which are covered more in detail in Appendix A.57.

Table 4.100: Nickel refinery utility and chemical requirements

Material flows	Value	Units
Nickel production rate (t)	8.56	t/hr
Electricity requirement (MWh)	24.8	MW
	2.90	t/t nickel
HP steam requirement @ 315°C and 10,000 kPa (t)	126	t/hr
	14.7	t/t nickel
H_2 requirement (t)	1.58	t/hr
	0.185	t/t nickel
H_2 for H_2S and plant balance (t)	0.625	t/hr
	0.0730	t/t nickel
H_2 for NH_3 (t)	0.958	t/hr
	0.112	t/t nickel
H_2S requirement (t)	0.183	t/hr
	0.021	t/t nickel
Sulphur requirement (t)	0.172	t/hr
	0.0201	t/t nickel
NH_3 requirement (t)	5.46	t/hr
	0.64	t/t nickel

4.6.3.4. NATURAL GAS UTILITY SYSTEM FOR NICKEL REFINERY

The natural gas utility system provides power, steam and chemicals for the nickel plant. It is a combination of a natural gas-based cogeneration plant from Chapter 4.6.2.2, a SMR plant from Chapter 4.5.2.2, a H_2S plant and a NH_3 synthesis unit. A flowsheet of the combined system is shown in Figure 4.41.

The H_2 plant is required to supply H_2 for the nickel refinery, the H_2S plant and the NH_3 plant. The H_2S plant converts H_2 and elemental sulphur into H_2S. The ASU takes in air and separates N_2 from O_2. The N_2 is reacted with H_2 to produce NH_3. The PSA tail gas from the hydrogen plant is combusted in a boiler to produce additional steam to meet the nickel refinery steam demand. A cogeneration system similar to the one found in the alumina refinery utility case is sized to meet the remaining steam requirements and produce excess power than is required by the nickel refinery.

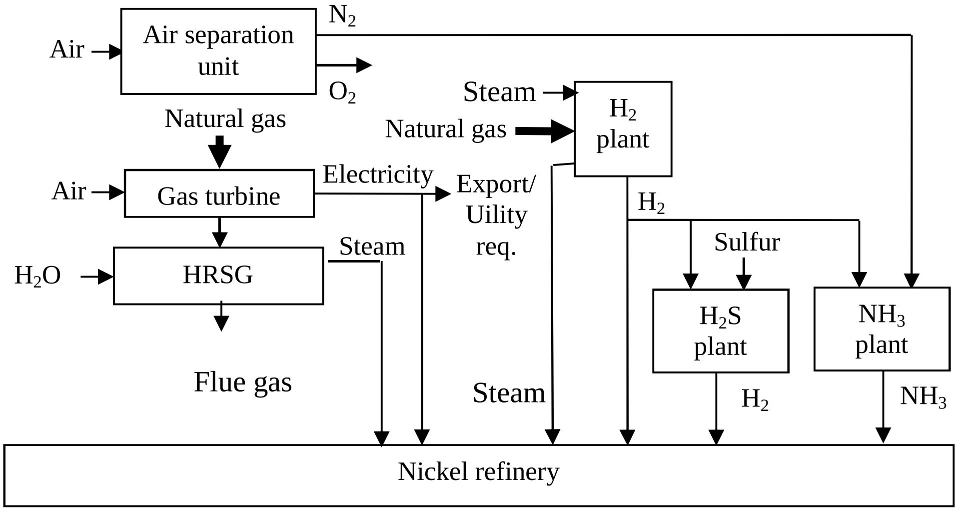


Figure 4.41: Natural gas usage to meet utility demand of nickel refinery

4.6.3.4.1. Material flows

The procedure to calculate the requirements for a natural gas-based utility system for the nickel refinery is covered in detail in Appendix A.58. Table 4.101 summarises the material flows for natural gas, electricity, steam and chemicals in the natural gas/CSG utility and chemicals system for a 205 t/day nickel refinery.

Table 4.101: Material flows for utilities and chemicals system in a 205 t/day nickel refinery

Material flows	Values	Units
Gas turbine/HRSG		
Natural gas to gas turbine @ 51.34 GJ/t NG HHV (t)	13.9	t NG/hr
	1.63	t NG/t nickel
Electricity generated (MWh)	65.2	MW
	7.62	MWh/t nickel
HP steam generated @ 315°C and 10,000 kPa (t)	119	t steam/hr
	13.9	t steam/t nickel
Hydrogen plant		
Natural gas feed and fuel @ 51.34 GJ/t NG HHV (t)	5.10	t/hr
	0.595	t/t nickel
Hydrogen produced (t)	1.59	t/hr
	0.185	t/t nickel
HP steam generated @ 315°C and 10,000 kPa (t)	6.64	t/hr
	0.775	t/t nickel
Electricity consumed	0.903	MW
	0.105	MWh/t nickel
Natural gas usage		
Total natural gas usage @ 51.34 GJ/t NG HHV (t)	19.0	t/hr
	2.22	t/t nickel
Other electricity usage		
Electricity consumed by ASU and NH_3 synthesis loop (MWh)	3.50	MW
	0.409	MWh/t nickel
Electricity export		
Electricity exported (MWh)	32.6	MW
	3.81	MWh/t nickel

Table 4.102 summarises the material flow inputs and emissions for a nickel refinery utility and chemicals system.

Table 4.102: Material flow data for the natural gas/CSG utility system in a nickel refinery

Inventory data	Units	Combined heat and power	H_2 plant	ASU and NH_3 synthesis loop	Electricity material flows [a]	Total	Category
Input							
Natural gas	t/t nickel	1.63	5.95E-01	0	-6.35E-02	2.16	Fuel/Feedstock
Black coal		0	0	0	-9.52E-01	-9.52E-01	Fuel
Cooling water	t/t nickel	0	1.54	5.50E-01	-5.92E+00	-3.83	Freshwater Withdrawal
Demineralised water	t/t nickel	1.35	2.40	0	-3.30E-01	3.42	Freshwater Withdrawal
Output							
Cooling water blowdown	t/t nickel	0	2.41E-01	8.60E-02	-6.41E-01	-3.14E-01	Saline Water Generation
Steam blowdown	t/t nickel	1.35	3.87E-02	0	-3.30E-01	1.06	Saline Water Generation
CO_2	t/t nickel	4.31	1.63	0	-2.22E+00	3.72	Global Warming Potential
CH_4	t/t nickel	4.00E-04	1.44E-05	0	-4.88E-05	3.66E-04	Global Warming Potential
N_2O	t/t nickel	8.19E-06	2.92E-07	0	-3.06E-05	-2.21E-05	Global Warming Potential
VOC	t/t nickel	5.10E-05	7.00E-06	0	-1.53E-05	4.27E-05	Photochemical Oxidation Potential
CO	t/t nickel	2.45E-03	1.07E-04	0	-4.90E-03	-2.35E-03	Photochemical Oxidation Potential
NO_x	t/t nickel	6.08E-03	1.27E-04	0	-3.34E-04	5.88E-03	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t nickel	2.14E-05	1.40E-06	0	-7.74E-03	-7.72E-03	Acidification Potential
PM_{10}	t/t nickel	2.36E-04	9.42E-06	0	-3.44E-04	-9.83E-05	Particulate Formation
Ash	t/t nickel	0	0	0	-2.02E-01	-2.02E-01	Solid Waste Generation Potential

[a] Electricity assumed to be generated using Australian reference grid electricity fuel mix (see Appendix A.20)

4.6.3.4.2. Capital cost

The capital cost of the natural gas-based utility system for the nickel refinery is calculated using CCGT plant cost data from Chapter 4.3.3.3.1, and plant cost data for both the SMR plant and the NH_3 synthesis unit from Chapter 4.5.3.2.2.

The CCGT plant capital cost was adapted from Bedilion et al. (2009). The literature also provided a breakdown of the capital costs of the CCGT plant which enables us to identify the equipment we wish to exclude from the final capital cost. The original CCGT plant had a dry cooling configuration and an efficiency of 49.5% HHV. Several adjustments are required to modify the plant for the nickel refinery, which is further detailed in Appendix A.59. Table 4.103 summarises the result of the adjustment process.

Table 4.103: Equipment cost breakdown for the nickel refinery cogeneration system (Costs are expressed in 2012A$)

Equipment items	**Cost (2012A$million)**
Feedwater & miscellaneous systems	6.9
Combustion turbine & accessories	46.5
HRSG, ducting and stack	23.7
Steam turbine generator (including accessories)	0.0
Cooling water system	0.0
Accessory electric plant	16.2
Instrumentation & controls	6.0
Improvements to site	5.4
Buildings and structures	5.7
Direct cost	**110.5**

The capital costs of the H_2 plant, ASU, NH_3 synthesis loop and H_2S plant are added to the direct cost of the cogeneration system. The cost of the H2S plant was assumed to be 10% of the direct plant cost. Table 4.104 shows the total capital cost of the utility system for the nickel refinery to be $175 million in 2011 Australian dollars. The calculations of the capital cost of the chemical components are covered in Appendix A.60.

Table 4.104: Capital cost components of the naturla gas/CSG chemical utility and chemicals system in a 205 t/day nickel refinery (Costs are expressed in 2012A$)

Plant component	Cost (2012A$million)
Cogeneration plant	110.0
Hydrogen plant	43.9
ASU	6.5
Ammonia synthesis plant	21.5
H_2S plant [a]	20.0
Direct plant cost	**202.0**
Engineering and project management [b]	50.5
Total plant cost	**253.0**

[a] Assumed to be 1/10 of direct plant cost

[b] Assumed to be 25% of direct plant cost

4.6.3.4.3. Operating cost

Table 4.105 and Table 4.106 show the operating cost model for the utility system using natural gas and CSG in a nickel refinery with the inclusion of the revenue generated from export electricity.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the natural gas utility system, there are eight process zones, which are the ASU, gas turbine, steam generation system, pre-treatment, reformer, shift and PSA as one zone, ammonia synthesis unit, and H_2S plant. An additional operator is required for the control room. Hence, nine process operators are required in total.

Table 4.105: Operating cost model for a natural gas based utility system in a nickel refinery (Costs are expressed in 2012A$)

Plant capacity	205	t nickel/day			
Plant availability	85%				
Annual actual production	63,800	t nickel/yr			
Fixed capital investment	253	$ million	(for utility system only)		
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	Australian dollars (A$)			
Operating costs				**Annual cost ($ million)**	**Cost per tonne ($/t nickel)**
Raw materials		Unit usage (/t nickel)	Unit cost ($/unit)		
Natural gas fuel/feedstock	t	2.22	179	25.33	397.00
Utilities		Unit usage (/t nickel)	Unit cost ($/unit)		
Cooling water	m3	83.4	0.0770	0.41	6.42
Demineralised water	t	6.04	1.50	0.58	9.06
Elemental sulphur	t	0.0201	117	0.00	2.35
Total variable costs				**26.32**	**414.82**
Byproducts		Unit usage (/t nickel)	Unit cost ($/unit)		
Export electricity	MWh	3.81	70.00	-17.01	-266.59
Export oxygen	t	0.01	170	-0.11	-1.69
Total byproduct costs				**-17.12**	**-268.29**
Operating labour		No.	Salary ($/yr)		
Operators/shift		9			
Shift teams		5			
Total shift operators		45	82,000	3.69	57.84
Total operating labour costs				**3.69**	**57.84**
Payroll overheads		40	% total operating labour cost	**1.48**	23.13
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.77	12.15
Maintenance labour		1		2.53	39.71
Maintenance materials		1		2.53	39.71
Consumables store			10	0.52	8.10
Plant overheads			100	5.17	80.97
Laboratory			10	0.52	8.10
Insurance		1		2.53	39.71
Property taxes		1		2.53	39.71
Total fixed costs				**22.27**	**349.10**
Total manufacturing costs				**31.47**	**495.64**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	1.03	16.20
Marketing costs		2	Total production cost	1.03	16.20
Research and development costs		2	Total production cost	1.03	16.20
General expenses				**3.10**	**48.61**
Total product cost				**34.57**	**544.25**

Table 4.106: Operating cost model for a CSG based utility system in an nickel refinery (Costs are expressed in 2012A$)

Plant capacity	205	t nickel/day			
Plant availability	85%				
Annual actual production	63,800	t nickel/yr			
Fixed capital investment	288	$ million	(for utility system only)		
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	Australian dollars (A$)			
Operating costs				**Annual cost ($ million)**	**Cost per tonne ($/t nickel)**
Raw materials		Unit usage (/t nickel)	Unit cost ($/unit)		
Coal seam gas fuel/feedstock	t	2.22	138	19.59	307.12
Utilities		Unit usage (/t nickel)	Unit cost ($/unit)		
Cooling water	m3	83.4	0.0770	0.41	6.42
Demineralised water	t	6.04	1.50	0.58	9.06
Elemental sulphur	t	0.0201	117	0.00	2.35
Total variable costs				**20.58**	**324.95**
Byproducts		Unit usage (/t nickel)	Unit cost ($/unit)		
Export electricity	MWh	3.81	70.00	-17.01	-266.59
Export oxygen	t	0.0100	170	-0.11	-1.69
Total byproduct costs				**-17.12**	**-268.29**
Operating labour		No.	Salary ($/yr)		
Operators/shift		9			
Shift teams		5			
Total shift operators		45	82,000	3.69	57.84
Total operating labour costs				**3.69**	**57.84**
Payroll overheads		40	% total operating labour cost	**1.48**	23.13
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.77	12.15
Maintenance labour		1		2.88	45.17
Maintenance materials		1		2.88	45.17
Consumables store			10	0.52	8.10
Plant overheads			100	5.17	80.97
Laboratory			10	0.52	8.10
Insurance		1		2.88	45.17
Property taxes		1		2.88	45.17
Total fixed costs				**23.67**	**370.96**
Total manufacturing costs				**27.13**	**427.62**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	0.94	14.76
Marketing costs		2	Total production cost	0.94	14.76
Research and development costs		2	Total production cost	0.94	14.76
General expenses				**2.82**	**44.27**
Total product cost				**29.96**	**471.89**

Table 4.107 summarises the total operating cost for the natural gas/CSG utility system for the nickel refinery, which is made up of annualised capital costs and cash operating costs. Electricity export to the grid will reduce the total operating cost by around 25% for natural gas and CSG.

Table 4.107: Total operating costs for natural gas/CSG utility systems in a 205 t/day nickel refinery (Costs are expressed in 2012A$)

Capacity (t/day nickel)		205			
Output (t/year nickel)		63,800			
Annualised capital costs (A$/t nickel)		422			
Export electricity @ $70/MWh and oxygen revenue @ $170/MWh		Excluded		Included	
Feedstock type		NG	CSG	NG	CSG
Cash operating costs	Variable costs (A$/t nickel)	415	325	147	56.7
	Fixed costs (A$/t nickel)	349	349	349	349
	Other costs (A$/t nickel)	48.6	42.9	48.6	42.9
	Total (A$/t nickel)	813	717	544	449
Total operating costs (A$/t nickel)		1,230	1,140	966	870

4.6.3.5. BLACK COAL UTILITY SYSTEM

An integrated IGCC and chemicals plant is required to supply the material requirements of the nickel refinery with black coal feedstock as shown in Figure 4.42. The steam turbine is excluded from the IGCC design as the steam will be used to meet the nickel refinery steam requirement. First, black coal is gasified to create syngas. A portion of the syngas will be fired in a gas turbine to generate power and flue gas heat is captured in a HRSG to produce the required steam. The remainder syngas undergoes shift reaction and acid gas removal to be converted into hydrogen, which can then be used to produce NH_3 and meet other hydrogen demands around the nickel plant for nickel reduction and H_2S generation. A sweet shift configuration is used as the H_2S can be extracted after the syngas clean-up stage and used to meet the nickel refinery H_2S requirement. PSA tail gas is also combusted in a boiler to produce additional steam which can partially meet the steam requirements. N_2 is taken from the existing ASU and fed into the ammonia synthesis unit to produce ammonia.

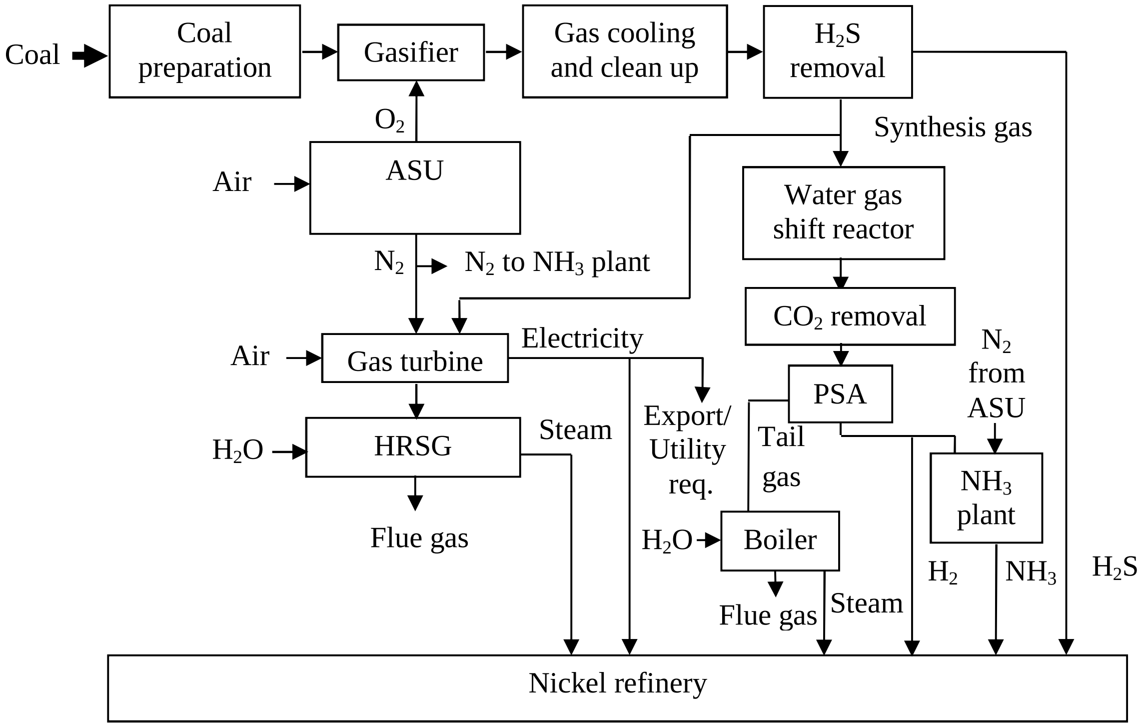


Figure 4.42: Black coal usage to meet utility demand of nickel refinery

4.6.3.5.1. Material flows

Table 4.108 summarises the material flows of a black coal utility and chemicals system in a 205 t/day nickel refinery on the basis of one t nickel metal produced from the refinery. The material flows of the black coal utility system is assumed to be based on a combination of IGCC material flow data from Table 4.38 and hydrogen material flow data from Table 4.77 in Section 4.5.2.3.1. The former is based on the amount of the amount of electricity generated from the gas turbine and the latter is based on the amount of hydrogen produced to meet the refinery demand.

Table 4.108: Plant performance for the black coal utility and chemicals system in a 205 t/day nickel refinery

Material flows	**Value**	**Units**
Gasifier		
Coal to gasifier @ 24.4 GJ/t coal HHV	50.0	t/hr
	5.84	t/t nickel
Syngas exiting gasifier	88.0	t/hr
	10.3	t/t nickel
Electricity consumed by auxiliary equipment	37.2	MW
	4.35	MWh/t nickel
Gas turbine/HRSG		
Syngas to gas turbine	63.1	t/hr
	7.37	t/t nickel
Gross electricity generated	96.9	MW
	11.3	MWh/t nickel
HP steam generated from flue gas @ 315°C and 10,000 kPa	123	t/hr
	14.4	t/t nickel
Hydrogen plant		
Syngas to hydrogen plant	25.0	t/hr
	2.92	t/t nickel
Electricity consumed	5.5	MW
	0.64	MWh/t nickel
Hydrogen produced	38	t/day
	0.19	t/t nickel
HP steam generated from offgas @ 315°C and 10,000 kPa	2.34	t/hr
	0.27	t/t nickel
Other electricity usage		
Electricity consumed by NH_3 synthesis loop	3.5	MW
	0.41	t/t nickel
Electricity		
Electricity exported	25.8	MW
	3.02	t/t nickel

One advantage of the black coal utility and chemicals system is that H_2S is produced as a by-product and separated from the syngas stream in the acid gas removal process, thus eliminating the need for the H_2S plant. The Australian reference coal used in this analysis has 0.6% sulphur content (see Chapter 4.1.4 for coal composition). Assuming all sulphur can be converted to H_2S, this will produce 0.027 t H_2S/t nickel, which exceeds the nickel refinery H_2S requirement in Table 4.100. A mass balance for the black coal nickel refinery utility system is located in Appendix A.61. HYSYS models for the gas turbine and HRSG section (Appendix A.62) and for the PSA off-gas boiler (Appendix A.63) are used to calculate the amount of steam recovered and power generated from black coal. Appendix A.64 outlines full details on calculating the values in Table 4.108.

Table 4.109 summarises the material inputs and emissions for a nickel refinery.

Table 4.109: Material flow data for the black coal utility and chemicals system in a nickel refinery

Inventory data	Units	IGCC	H_2 plant	NH_3 synthesis loop	Electricity material flows [a]	Total	Category
Input							
Black coal	t/t nickel	4.18	1.66	0	-1.10E+00	5.84	Fuel/Feedstock
Cooling water makeup	t/t nickel	0	2.17	5.13E-01	-5.73E+00	2.68	Freshwater Withdrawal
Demineralised water	t/t nickel	34.9	5.96	0	-3.02E-01	40.9	Freshwater Withdrawal
Output							
Cooling water blowdown	t/t nickel	0	2.84E-01	8.02E-02	-6.04E-01	3.64E-01	Contaminated Water Generation
Steam blowdown	t/t nickel	34.9	0	0	-3.02E-01	34.9	Contaminated Water Generation
CO_2	t/t nickel	9.79	3.87	0	-2.36E+00	13.7	Global Warming Potential
CH_4	t/t nickel	5.90E-05	1.38E-05	0	-3.83E-05	7.28E-05	Global Warming Potential
N_2O	t/t nickel	6.79E-08	1.58E-08	0	-1.73E-05	8.37E-08	Global Warming Potential
NMVOC	t/t nickel	4.17E-07	9.73E-08	0	-2.01E-08	5.14E-07	Photochemical Oxidation Potential
CO	t/t nickel	7.47E-06	1.64E-04	0	-2.75E-04	1.72E-04	Photochemical Oxidation Potential
NO_x	t/t nickel	4.57E-03	1.07E-03	0	-5.37E-03	5.64E-03	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/t nickel	3.62E-04	1.43E-04	0	-1.42E-08	5.05E-04	Acidification Potential
PM_{10}	t/t nickel	5.96E-04	1.39E-04	0	-3.85E-04	7.35E-04	Particulate Formation
Ash	t/t nickel	8.20E-01	2.92E-01	0	-2.32E-01	1.11	Particulate Formation

[a] Electricity assumed to be generated from PCST power station.

4.6.3.5.2. Capital cost

The capital cost of the black coal utility and chemicals system was approximated using the capital cost of an IGCC power station as reported by Bedilion et al. (2009) as a guideline. The IGCC power station was sized to handle the coal feedstock requirements for the utility system of a 205 t/day nickel refinery, which was 50 t/hr coal or 5.84 t/t nickel. The gas turbine and HRSG were sized to generate a gross electrical output of around 96.9 MW and it was assumed to have an electrical efficiency of 36%. The auxiliary duty for the gasifier and the duty for the ammonia synthesis loop were taken out from the total gross output. The cost associated with the steam turbine generator was identified and removed from the total capital cost of the plant. Cooling water equipment costs were removed as the digester acts as the heat sink for the high pressure steam. The capital costs were adjusted from 2009 Australian dollars to 2012 Australian dollars using Equation 4.5.

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad \text{(Equation 4.5)}$$

The capital cost breakdown for the black coal utility and chemicals system, excluding the costs of the chemical manufacture components, is shown in Table 4.110 to be $794 million in 2012 Australian dollars. Full details to calculate the capital cost of the black coal-based utility system for the nickel refinery is covered in Appendix A.65.

Table 4.110: Equipment cost breakdown for the 55 MW power generation component of the black coal utility and chemicals system (Costs are expressed in 2012A$)

Equipment items	**Cost (2012A$million)**
Coal and fluxant/sorbent handling	28.4
Coal and fluxant/sorbent preparation & feed	118.5
Feedwater & miscellaneous systems	13.0
Gasifier, ASU & accessories	376.6
Gas cleanup & piping/flue gas cleanup	54.1
Combustion turbine & accessories	52.3
HRSG, ducting and stack	31.9
Steam turbine generator (including accessories)	-
Cooling water system	-
Ash/spent sorbent handling	36.6
Accessory electric plant	43.7
Instrumentation & controls	13.0
Improvements to site	12.9
Buildings and structures	12.9
Direct cost	**794.0**

The components associated with hydrogen and ammonia productions were then added to the capital cost above. The capital costs for the hydrogen separation and clean-up equipment and the ammonia synthesis loop were adopted from Rutkowski (2008) and Morgan (2013) respectively. These costs are relatively minor when compared to the overall capital cost for the entire system. This brings the total capital cost for the black coal utility system up to around $1.03 billion in 2012 Australian dollars as shown in Table 4.111. Full details to calculate the chemical components are located in Appendix A.66.

Table 4.111: Capital cost of the hydrogen and ammonia components of the black coal utility and chemicals system in a 205 t/day nickel refinery (Costs are expressed in 2012 A$)

Plant component	**Capital cost (2012A$million)**
Power generation	794.0
Hydrogen separation and purification	23.1
Ammonia synthesis plant	21.6
Direct plant cost	**839.0**
Engineering and project management	210.0
Total plant cost	**1,050.0**

Note: H_2S separation is a component of hydrogen separation and purification.

4.6.3.5.3. Operating costs

The operating cost model for the black coal utility in a nickel refinery is shown in Table 4.112 with the export electricity credits included.

The number of operators is estimated based on the number of process zones. Each process zone is allocated one operator. For the coal utility system, there are seven process zones, which are the coal preparation, ASU, gasifier, syngas cooling and cleaning, acid gas removal, gas turbine, steam generation system, shift and PSA as one zone and the ammonia synthesis unit. An additional operator is required for the control room. Hence, ten process operators are required in total.

Table 4.112: Operating cost model for the black coal based utility system in a nickel refinery (Costs are expressed in 2012A$)

Plant capacity	205	t nickel/day			
Plant availability	85%				
Annual actual production	63,800	t nickel/yr			
Fixed capital investment	1,048	$ million	(for utility system only)		
Capital exponent,ψ (I=αQψ)	0.7				
Cost year	2012	Australian dollars (A$)			
Operating costs				**Annual cost ($ million)**	**Cost per tonne ($/t nickel)**
Raw materials		Unit usage (/t nickel)	Unit cost ($/unit)		
Black coal fuel/feedstock	t	5.84	33.1	12.35	193.52
Utilities		Unit usage (/t nickel)	Unit cost ($/unit)		
Cooling water	m3	140	0.0770	0.69	10.76
Demineralised water	t	40.82	1.50	3.91	61.23
Total variable costs				**16.94**	**265.51**
Byproducts		Unit usage (/t nickel)	Unit cost ($/unit)		
Export electricity	MWh	3.02	70.00	-13.48	-211.28
Total byproduct costs				**-13.48**	**-211.28**
Operating labour		No.	Salary ($/yr)		
Operators/shift		10			
Shift teams		5			
Total shift operators		50	82,000	4.10	64.26
Total operating labour costs				**4.10**	**64.26**
Payroll overheads		40	% total operating labour cost	**1.64**	25.71
		% fixed capital	**% operating labour + payroll overheads**		
Supervision			15	0.86	13.50
Maintenance labour		1		10.48	164.32
Maintenance materials		1		10.48	164.32
Consumables store			10	0.57	9.00
Plant overheads			100	5.74	89.97
Laboratory			10	0.57	9.00
Insurance		1		10.48	164.32
Property taxes		1		10.48	164.32
Total fixed costs				**55.42**	**868.73**
Total manufacturing costs				**58.89**	**922.96**
Non-manufacturing costs		(%)	Factor		
Administrative costs		2	Total production cost	1.54	24.13
Marketing costs		2	Total production cost	1.54	24.13
Research and development costs		2	Total production cost	1.54	24.13
General expenses				**4.62**	**72.40**
Total product cost				**63.50**	**995.36**

Table 4.113 summarises the total operating cost for the black coal utility system, which is the sum of the annualised capital costs and cash operating costs.

Table 4.113: Total operating costs for black coal utility systems in a 205 t/day nickel refinery (Costs are expressed in 2012A$)

Capacity (t/day nickel)		205	
Output (t/year nickel)		63,800	
Annualised capital costs (A$/t nickel)		1,745	
Export electricity revenue @ $70/MWh		Excluded	Included
Cash operating costs	Variable costs (A$/t nickel)	266	54.2
	Fixed costs (A$/t nickel)	869	869
	Other costs (A$/t nickel)	72.4	72.4
	Total (A$/t nickel)	1,210	995
Total operating costs (A$/t nickel)		2,950	2,740

4.6.3.6. SUBSTITUTION IMPACTS FOR NICKEL REFINERY UTILITY SYSTEM

Table 4.114 summarises the environmental and economic impacts that result from the substitution of a natural gas utility system in a nickel refinery with a black coal or a CSG utility system. For the operating costs of all feedstock cases, the revenue from electricity export was included.

Similar to the alumina refining case, the environmental impacts due to the offset of emissions by the export of electricity have been taken into account for the natural gas, black coal and CSG cases. However, the nickel refining case reported more positive substitution impact indicators for environmental impacts than the alumina refining case. Substitution with black coal resulted not only in an increase in greenhouse gas emissions, particulates and solid waste generation as with the alumina refining case, but also in the freshwater withdrawal and saline water generation. This indicates that the black coal-based nickel refinery consumes significantly more water than the natural gas-based refinery.

Similar to substitution in the alumina refinery utility systems, the annualised capital costs make up the majority of the increase in operating costs for substitution in nickel refinery utility systems. This increase was observed to be larger than that for substitution in alumina refinery utility systems due to the larger capital cost per tonne of product.

Full details of the calculations of the substitution indicators are shown in Appendix A.67.

Table 4.114: Substitution impact indicators for nickel refinery utility systems in Australia

Option	Nickel refinery utility system	
Feedstock	NG→BlC	NG→CSG
Technology	Cogen+SMR→IGCC	Cogen+SMR
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	+ 6.06E-09	- 1.14E-10
Acidification Potential (ADP)	- 1.26E-09	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 2.87E-09	- 3.93E-09
Particulate Matter Formation (PMF)	+ 2.02E-10	- 9.29E-11
Freshwater Withdrawal (FWW)	+ 1.95E-10	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 1.44E-08
Saline Water Generation (CWG)	+ 2.39E-10	- 7.17E-13
Solid Waste Generation (SWG)	+ 1.79E-07	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+ 785.0	-
Cash operating costs	+ 298.0	- 43.1
Total operating costs	+ 1,080.0	- 43.1

Legend: ‘+’ sign denotes increase in impacts, ‘-‘ sign denotes decrease in impacts, NG=Natural Gas, BlC=Black Coal, CSG=Coal Seam Gas, Cogen=Cogeneration, SMR=Steam Methane Reforming, IGCC=Integrated Gasification and Combined Cycle

Note: Environmental impact indicators include upstream and downstream impacts.

4.7. RESIDENTIAL HEATING

4.7.1. GAS HEATING IN AUSTRALIA

Heating is one of the largest single energy users in the Australian residential sector and accounts for 38% of total residential energy consumption in 2007 (EES 2008). According to Table 4.115, natural gas has the largest share of residential heating energy supply in 2007, followed by wood, electricity and LPG. The share of natural gas usage in residential heating is projected to increase in the following years as shown in Figure 4.43.

Table 4.115: Breakdown of energy for major end uses in Australia, units in PJ, 2007 (EES 2008)

	Mains gas	Electricity	Wood	LPG	Total
Space heating	81.3	13.4	51.3	3.6	149.6
Cooking	8.5	9.3	0	1.8	19.6
Water heating	44.7	43.1	0	2.9	90.7
Appliances	2.4[a]	122.5	0	0	124.9
Space cooling	0	11.9	0	0	11.9
Total	136.9	200.2	51.3	8.3	396.7

[a] Used mainly for heating of swimming pools and spas.

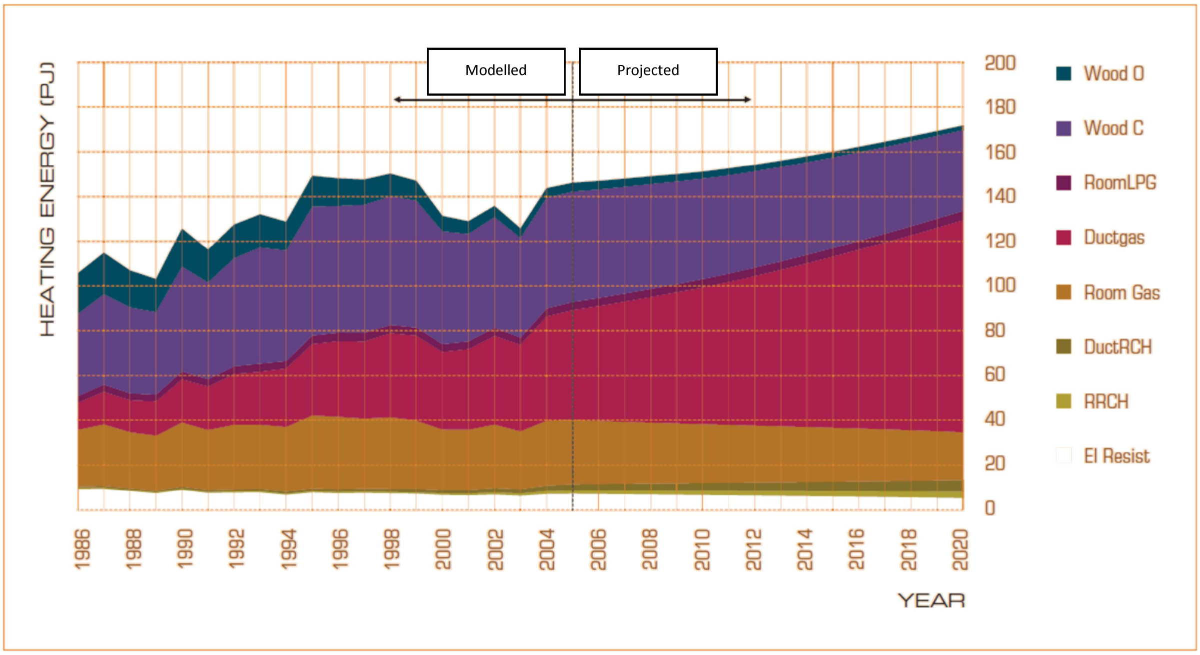


Figure 4.43: Trends in residential heating energy by fuel type in Australia, 1986 - 2020 (EES 2008)

Legend: Wood O = wood – open combustion; Wood C = wood – closed combustion; RoomLPG = LPG gas non-ducted (room heater); Ductgas = mains gas ducted; Room Gas = mains gas non-ducted (room heater); DuctRCH = air-conditioning reverse-cycle ducted; RCCH = air-conditioning reverse-cycle non-ducted; El Resist = electric resistive

2008 statistics in Table 4.116 show that Victoria has the largest number of households with ducted gas heating installed out of all the states in Australia, followed by New South Wales and the Australian Capital Territory. These states mentioned are located in cooler climates than the other states. Despite having a lower population than New South Wales, Victoria has an overall larger heating energy consumption due to the higher heating load from the cooler climate. Victoria has an extensive and well-established natural gas pipeline distribution network; hence natural gas is prevalent in many Victorian homes. Victorian households also generally demand higher standards of heating, particularly in terms of the extent of space heating in their households (i.e. whole house rather than room only heating). EES (2008) and EnergyConsult (2011) both report a significant trend shifting from room heating to central ducted space heating (mainly in Victoria) which has a higher zoning level and lower efficiency, hence higher energy consumption per household. Table 4.115 shows the share of residential heating from ducted gas systems increasing up to the year 2020. For this analysis, this chapter will focus mainly on the impacts of a natural gas shortage in residential homes with central ducted gas heating.

Table 4.116: Statistical data for gas ducted heating in Australia by state, 2008 (EnergyConsult 2011)

	NSW/ACT	NT	QLD	SA	TAS	VIC	WA
Number of households with ducted gas main heating	133,134 [a]	n/a	4,324	24,793	20	801,600	29,810
Total annual energy consumption by natural gas and LPG ducted heaters (GJ/yr) [b]	8,854	0	0	971	5	48,777	256
Average annual energy consumption by natural gas and LPG ducted heaters per household (GJ/yr) [b,c]	66.5	0	0	39.2	250	60.8	8.6
Average annual operating hours of gas ducted heaters per household (hr/yr)	576 [b]	n/a	130	316	1,200	588	250

Legend: n/a = not available

[a] Calculated by adding the number of households with ducted gas heating in NSW (80,931) and ACT (52,203)

[b] LPG heaters represent only 2% of the total stock of gas ducted heaters in Australia and are assumed to have a negligible contribution to the overall heating energy consumption

[c] Weighted according to an estimated share of two-third ACT and one-third NSW

[d] Calculated by dividing total annual energy consumption by number of households with ducted gas heating

4.7.2. DUCTED GAS HEATING

Natural gas is a primary energy source that can be burnt to produce direct heating with minimal contribution to local pollution, with minimal gas distribution losses and a rapid start-up time. This makes natural gas an energy efficient heating fuel for residential houses. Natural gas usage requires a connection to an existing natural gas pipeline network. Natural gas heating systems are preferable in colder climates as they are able to provide a consistent heating performance.

There are a variety of heating options using natural gas. Direct heat from combustion of natural gas can be used to heat up an area or a single area in space heaters, or circulated around multiple zones or a whole house through central ducted heating systems. There are two types of gas space heaters: Flueless and flued. Flueless heaters release the heat, water vapour and other gases including carbon monoxide and nitrogen oxides produced from gas combustion into the living space, hence adequate ventilation is required to reduce occupant exposure. Flued heaters release the combustion by-products external to the living space. Ducted gas heating systems fall under the flued category. Unbalanced flued space heaters and flueless space heaters draw air for combustion from the living room space, reducing the pressure inside and drawing in outside air. Balanced flued space heaters, on the other hand, take combustion air from outside.

Another heating method is through hydronic heating, where natural gas is combusted in boilers to heat water, which is then circulated around the house through radiation or convection. Hydronic systems usually have high capital costs and significant time lags during start-up and shutdown, but have the additional benefit of potentially providing domestic hot water. Hydronic heating systems are more suitable for cold climates requiring constant heating, such as the alpine regions of Victoria.

In Australia, ducted gas heating systems have become the dominant heating option for households, especially in Victoria. In ducted gas systems, air is heated by a gas furnace (generally to 50°C to 60°C, sometimes to 80°C) and is transferred to nominated rooms through insulated flexible ducts and discharged through air outlets (supply air registers). Colder air is drawn back to the return air grille and passed through a filter to collect dust before being returned to the furnace. A central heating system can be configured to heat either the whole house or certain rooms or zones. Furnaces are located either indoors or outdoors. A 5-star internal gas ducted system consists of the following main components:

- Cabinet insulated with aluminium foil and insulation material
- Heat exchanger (possibly accompanied by a secondary condensing heat exchanger
- Main blower
- Gas control valves and burners (single stage or dual stage for high and low fire and variable control)
- Spark ignition (also available in solid state)
- Control board to control temperatures, gas, air purge, and the main blower with inputs for add-on air conditioning
- Accessories such as humidifier, zoning and electrostatic air filters

Gas ducted heating furnaces in Australia are tested and assigned a gas energy rating label as detailed in the Australian Standard AS4556, with a scale indicating efficiency from 1 to 6. Natural draught combustion process heaters are of standard efficiency (1 to 2 star rating). Fan assisted combustion process heaters are of mid-efficiency range (3 to 4 star rating) and are traditionally designed to extract only sensible heat from the combustion gases generated by their burner/heat exchanger systems. The fuel conversion efficiencies do not go higher than 85 percent. The addition of a condensing heater or secondary heat exchanger is able to recover the energy contained in the heated exhaust gases, which is normally lost to the atmosphere when discharged through the flue. This raises the overall heat exchanger thermal efficiency to around 90 to 95 percent (5 to 6 star rating). However, warm air losses from ductwork, thermal losses through duct walls and drawing in of colder external air to the house through leakage will lower the efficiency of a gas ducted system.

4.7.2.1. MATERIAL FLOWS

There are two main energy consumption sources in the natural gas/CSG ducted gas system: the gas furnace and the electric fan component.

The fuel usage and emissions to air for the gas furnace were modelled after a gas boiler system using material flow data from Table 4.59 in Section 4.4.3.1. The emissions were reported using a basis of per t gas combusted. To adjust the emissions to a basis of per GJ heating provided, the efficiency of the gas ducted system is required. According to Palmer (2008), a 5-star gas ducted system has an efficiency of 90%. With 10% ductwork losses, the efficiency reduces to 81%.

As for the electric fan component, Palmer (2008) reported that a 20 kW gas ducted heating system will consume 0.4 kW of electricity when operating at 100% efficiency (i.e. providing 20 kW heating to the house). For every 1 GJ of heating, this is equivalent to 5.6 kWh of electricity consumed. This electricity was assumed to be generated from a CCGT power station, which were adopted from Table 4.29.

The adjusted material flow data for the natural gas/CSG ducted system is shown in Table 4.117.

Table 4.117: Material flow data for ducted gas heating in residential homes using natural gas

Inventory data	Units	Natural gas combustion (furnace)	Electricity (fan) [a]	Total	Category
Input					
Natural gas	t/GJ heating	2.40E-02	8.50E-05	2.41E-02	Fuel
Black coal	t/GJ heating	0	1.28E-03		
Cooling water makeup	t/GJ heating	0	7.92E-03	7.92E-03	Freshwater Withdrawal
Boiler feedwater makeup	t/GJ heating	0	4.42E-04	4.42E-04	Freshwater Withdrawal
Output					
Cooling water blowdown	t/GJ heating	0	6.67E-04	6.67E-04	Process Contaminated Water
Steam blowdown	t/GJ heating	0	4.44E-04	4.44E-04	Process Contaminated Water
CO_2	t/GJ heating	7.44E-02	1.86E-03	7.63E-02	Global Warming Potential
CH_4	t/GJ heating	6.92E-06	1.73E-07	7.09E-06	Global Warming Potential
N_2O	t/GJ heating	1.41E-07	3.54E-09	1.45E-07	Global Warming Potential
VOC	t/GJ heating	3.37E-06	2.22E-08	3.39E-06	Photochemical Oxidation Potential
CO	t/GJ heating	5.15E-05	1.06E-06	5.26E-05	Photochemical Oxidation Potential
NO_x	t/GJ heating	1.95E-05	2.63E-06	2.21E-05	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/GJ heating	6.75E-07	9.25E-09	6.84E-07	Acidification Potential

[a] Electricity is assumed to originate from a natural gas combined cycle gas turbine power station.

4.7.2.2. CAPITAL COST

To calculate the capital cost of a natural gas ducted heating system, the size of the gas ducting system in units of kilowatts (kW) for an average household is required. According to EnergyConsult (2011), 801,600 households in Victoria had ducted gas heating in 2008. In the same year, 48,777 TJ/yr of energy was consumed for residential heating. This equated to 60.8 GJ/yr or 16.9 MWh/yr for an average household. The average household in Victoria used gas ducted heaters for an average of 588 hours per year in 2008, which gave the heater size of approximately 29 kW for a single household. These calculations were performing with the assumption that each and every household uses a heating system with the same energy star rating. In reality, there are households with 2, 3, 4 or 5 star heaters, each with different fuel consumptions. Palmer (2008) approximates the capital cost of a 5 star ducted gas heating system to be $200/kW in 2008 Australian dollars including installation, which is equivalent to around $272/kW in 2012 Australian dollars. A 29 kW ducted gas heating system would then have a capital cost of $7,888 per unit.

4.7.2.3. OPERATING COSTS

The cost of natural gas paid by residential customers included not only the extraction and purification costs, i.e. the transfer cost of natural gas, but also network costs, retail costs and costs associated with the carbon price. In all states except Victoria, the price of retail services for both electricity and gas is set by the government. In Victoria, the price is unregulated and is determined by the retailers. Any increase in the costs to provide retailer services can be transferred down to the customer as an increase in the price the customer pays for their electricity and gas. Table 4.118 summarises the breakdown of a typical electricity and gas bill for a residential customer. Data for gas is limited, as only New South Wales regulates gas prices for small customers. Pipeline charges are the most significant component of the gas retail price, while wholesale energy costs and retailer operating costs are slightly higher for gas than for electricity. The retail price of gas includes allowance for the carbon price which was introduced in July 2012.

Table 4.118: Indicative composition of residential electricity and gas bills of a typical household, units in % (AER 2013)

Jurisdiction	Network costs	Wholesale energy costs	Retail costs	Carbon costs	Green costs
Electricity					
Queensland	52	21	15	9	3
New South Wales	51	23	10	7	8
Victoria	36	n/a	n/a	8	4
South Australia	55	21	13	4	8
Tasmania	57	27	9	3	4
ACT	43	26	11	12	8
Gas					
New South Wales	48	28	19	5	0

Legend: n/a = not available

Note: The breakdown of wholesale energy and retail costs for electricity in Victoria were not provided.

Typically, a gas bill will be divided into two components: a fixed supply charge and a usage charge. The fixed supply charge includes some of the costs of pipeline and retail operations. The usage charge is based on the amount of gas used by the customer and generally includes the cost of gas extraction and purification, the bulk of the transmission and distribution costs, retail costs and the costs associated with the carbon price.

The total operating cost for the ducted gas system is a combination of annualised capital cost of the heating system and the cost of natural gas fuel supply. The annualised capital cost was calculated using an average life of gas ducted heaters of 15 years and a discount rate of 7% (Palmer 2008, EnergyConsult 2011). Both the life span and the discount rate of ducted heating systems were lower than the default values assumed for larger standalone plants.

To calculate the cost of gas paid by retail customers, the price and usage of gas is required. The gas price was estimated to be a factor of 3.57 over the transfer price and accounts for extraction and purification, distribution, retail and carbon costs. For natural gas, the corresponding retail price was calculated to be $12.5/GJ or 1.25 c/MJ; for CSG, this was $9.61/GJ or 0.96 c/MJ.

As for gas usage, Victoria reported a heating energy consumption per household of 60.8 GJ/yr. Assuming the ducted gas heating system for each and every household has a 5 star rating and an efficiency of 81%; this gives a natural gas consumption of 75 GJ/yr.

The cost components for gas heating using natural gas and CSG are shown in Table 4.119. For this analysis, cleaning and maintenance costs for the ducted gas system were considered minor and not included.

Table 4.119: Total operating costs for residential ducted gas heating systems in an average household in Victoria, showing the natural gas case and the CSG case (Costs are expressed in 2012A$)

Parameters	**NG**	**CSG**	**Units**
Annualised capital costs			
Ducted gas heating capacity @ 81% efficiency	29		kW
Capital cost of ducted gas heating system (incl. ductwork and installation)	7,280		A$
Annualised capital cost	800		A$/yr
	13.1		$\$/\text{GJ}_{\text{heat}}$
Cash operating costs			
Average annual heating energy required	60.9		$\text{GJ}_{\text{heat/}}$yr
Furnace fuel energy usage	75.1		GJ/yr
	1.23		$\text{GJ}/\text{GJ}_{\text{heat}}$
Gas fuel cost	12.5	9.61	A$/GJ
Furnace operation cost	934	722	A$/yr
	15.3	11.9	$\text{A\$}/\text{GJ}_{\text{heat}}$
Grid electricity cost [a]	179	179	A$/MWh
Electric fan energy usage	0.1		MWh/yr
	0.002		$\text{MWh}/\text{GJ}_{\text{heat}}$
Electric fan operation cost	16.9	16.9	A$/yr
	0.28	0.28	$\text{A\$}/\text{GJ}_{\text{heat}}$
Total operating cost	1,750	1,540	A$/yr
	28.5	25.0	$\text{A\$}/\text{GJ}_{\text{heat}}$

[a] Assume $70/MWh for baseline grid electricity, multiplied by a factor of 2.56 (see Chapter 4.7.3.3)

4.7.3. DUCTED AIR CONDITIONING

Where gas is not available, electricity can be used to run heating appliances in residential homes. Electric resistance heaters, such as bar radiators, fan heaters, convection heaters, oil filled bar heaters, convective panels and radiant heat panels, convert electricity into heat at an efficiency of 100%. However, the use of electricity results in high running costs and has a high greenhouse emission profile.

Reverse cycle air conditioning offers an advantage over electric resistance heaters due their higher efficiencies reaching 380%. The high coefficient-of-performance (COP) of reverse cycle heat pumps makes the running cost comparable with natural gas in moderate winter climates. Unlike gas, these systems can also provide cooling in summer and the difference in prices for models with and without a cooling option is relatively small. On the other hand, heat pumps operate with reduced performance at low outdoor temperatures, and are generally unsuitable with cold climates. This increases energy consumption and reduces heating performance when it is most needed.

Similar to natural gas systems, reverse cycle heat pumps can be configured to run as space heaters to heat up a room or area, or run as a central ducted unit to heat multiple zones or the whole house. Wall mounted split units blow warm air from a single high position on a wall and may cause stratification. Reverse cycle ducted systems will produce lower levels of stratification by improving the distribution of the air, combined with regular air changes due to the constant running fan drawing air back to a return air grille.

In this analysis, a natural gas shortage will require substitution of the natural gas ducted heating system with a ducted air conditioning system. The ductwork remains intact, hence only the heater requires changing.

For this analysis, the COP was also assumed to be constant throughout the year and the effect of the outside temperature on the efficiency of the ducted air conditioning system is ignored.

4.7.3.1. MATERIAL FLOWS

Within the system boundary of the residential house, electric heat pumps do not release emissions as gas heating systems do. All emissions to air and related environmental impacts occur outside the system boundary, e.g. at the mine or the power station. Palmer (2008) reports a reverse cycle split system to have a COP of 3.8 or an efficiency of 380%. For a ducted air conditioning with 10% ductwork losses, the efficiency reduces to 342%. This means that for every GJ of heating, approximately 81 kWh of electricity is required. The material data for the generation of electricity required for 1 GJ of the ducted air conditioning system is shown in Table 4.120. To represent the whole of Australia, the electricity used for residential heating was assumed to be generated from black coal using pulverised coal steam turbine technology. To simplify the analysis, this was assumed to apply for Victoria and South Australia as well, both of which mainly use brown coal instead of black coal for power generation.

Similar to the ducted gas case, the ducted air conditioning system requires an electric fan component as well. It was assumed that for every 1 GJ of heating, 5.6 kWh of electricity is consumed. This electricity was assumed to be generated from a PCST power station, which were adopted from Table 4.36 in Section 4.3.4.2.1.

Table 4.120: Material flow data for the generation of 1 GJ heating from reverse cycle heat pumps

Inventory data	Units	Reverse cycle heat pump	Electric fan	Total	Category
Input					
Black coal	t/GJ heating	2.66E-02	1.82E-03	2.85E-02	Fuel
Cooling water makeup	t/GJ heating	1.54E-01	1.06E-02	1.65E-01	Freshwater Withdrawal
Boiler feedwater makeup	t/GJ heating	8.12E-03	5.56E-04	8.68E-03	Freshwater Withdrawal
Output					
Cooling water blowdown	t/GJ heating	1.62E-02	1.11E-03	1.73E-02	Process Contaminated Water
Steam blowdown	t/GJ heating	8.12E-03	5.56E-04	8.68E-03	Process Contaminated Water
CO_2	t/GJ heating	5.74E-02	3.92E-03	6.13E-02	Global Warming Potential
CH_4	t/GJ heating	9.29E-07	6.36E-08	9.93E-07	Global Warming Potential
N_2O	t/GJ heating	4.20E-07	2.87E-08	4.48E-07	Global Warming Potential
VOC	t/GJ heating	7.99E-07	5.47E-08	8.54E-07	Photochemical Oxidation Potential
CO	t/GJ heating	6.67E-06	4.56E-07	7.13E-06	Photochemical Oxidation Potential
NO_x	t/GJ heating	1.31E-04	8.93E-06	1.39E-04	Acidification Potential, Photochemical Oxidation Potential
SO_2	t/GJ heating	2.16E-04	1.48E-05	2.31E-04	Acidification Potential
PM	t/GJ heating	9.35E-06	6.40E-07	9.99E-06	Particulate Matter Formation
Ash	t/GJ heating	5.65E-03	3.86E-04	6.04E-03	Solid Waste Generation

Note: Electricity is assumed to originate from a black coal fired pulverised coal steam turbine power station

4.7.3.2. CAPITAL COST

The ducted air conditioning systems need to be sized to match that of the natural gas case. Palmer (2008) approximated the capital cost of a 5 star reverse cycle split system to be \$320/kW in 2008 Australian dollars including installation, which was equivalent to around \$405/kW in 2012 Australian dollars. A 29 kW ducted gas heating system in Victoria would then have a capital cost of \$11,700 per unit.

4.7.3.3. OPERATING COSTS

The cost of electricity paid by residential customers included the generation costs, network costs, retail costs, carbon costs and green costs. The breakdown of electricity prices for Queensland, New South Wales, Victoria, South Australia, Tasmania and ACT were summarised in Table 4.118 in Chapter 4.7.2.3. Victoria reported lower network costs as compared to the other states. The breakdown of wholesale energy and retail costs in Victoria, which were 52% of the total electricity bill, were not provided. The other states reported a ratio of wholesale energy costs to retail costs between 1.4 and 3. Assuming this ratio to be 3 for Victoria, the wholesale energy costs was estimated to be 39% of the total electricity bill while the retail costs were 13%. Using an electricity generation cost of \$85/MWh (i.e. the cost of electricity generated from black coal as calculated in Section 4.3.4.3.2), the price of electricity paid by retail customers was calculated to be 2.56 times the generation cost, giving a retail electricity price of \$281/MWh or 2.41 c/kWh. The total operating cost for the ducted gas system is a combination of annualised capital cost of the heating system and the cost of natural gas fuel supply. The electricity case assumes a life span of 15 years and 7% discount rate for the annualised capital cost. This is summarised in Table 4.121. Victoria reported a heating energy consumption per household of 60.8 GJ/yr. Assuming the ducted air conditioning system for each and every household has a 5 star rating and a COP of 3.42 (including 10% ductwork losses); this gives an electricity consumption of 4.94 MWh/yr for the reverse heat pumps. In addition, 0.1 MWh/yr is required to run the electric fans for the ducted system, making a total of 5 MWh/yr.

Table 4.121: Total operating costs for residential ducted air conditioning systems in an average household (Costs are expressed in 2012A$)

Parameters	**Value**	**Units**
Annualised capital cost		
Ducted air conditioning capacity @ COP = 3.42	29	kW
Capital cost of ducted gas heating system	11,700	A$
Annualised capital cost	1,120	A$/yr
	18.4	A$/GJ$_{heat}$
Cash operating cost		
Average annual heating energy required	60.8	GJ$_{heat}$/yr
Electricity price [a]	281	A$/MWh
Reverse heat pump energy usage	4.94	MWh/yr
	0.0813	MWh/GJ$_{heat}$
Reverse heat pump operation cost	1,390	A$/yr
	22.8	A$/GJ$_{heat}$
Electric fan energy usage	0.1	A$/yr
	0.002	A$/GJ$_{heat}$
Electric fan operation cost	26.4	A$/yr
	0.43	A$/GJ$_{heat}$
Total operating cost	2,540	A$/yr
	41.3	A$/GJ$_{heat}$

[a] Obtained from Section 4.3.4.3.2, multiplied by a factor of 2.56 (see Chapter 4.7.3.3)

4.7.4. RESIDENTIAL HEATING SUBSTITUTION INDICATOR

As Victoria consists of more than 80% of households with ducted gas heaters and has a share of 82% of Australia’s annual energy consumption in ducted gas heaters, this analysis examines the case of the substitution of natural gas in residential heating.

Table 4.122 summarises the environmental and economic impacts that result from the substitution of a natural ducted heating system with a ducted air conditioning fuelled by electricity generated using black coal or a CSG ducting heating system. A negative global warming potential was observed after the substitution with black coal, in addition to the photochemical oxidation potential and associated water values due to the higher photochemical oxidation emissions and associated water production in the natural gas extraction and processing stage. The decrease in greenhouse gas emissions after substitution with black coal indicates that the combination of high-efficiency reverse cycle heat pumps using coal-fired electricity produces less greenhouse gas emissions than combustion of natural gas for heating. However, this option will incur a large increase in annualised capital costs significantly for the average household that needs to replace its gas-based heating system with an electric heating system.

The decrease in operating costs per t natural gas substituted for substitution with CSG has been found to be larger than other sectors. This is because the total operating costs for residential heating reflect the retail prices that residential customers are paying for gas, which is approximately 3.57 times than that paid by industrial customers who pay for gas at the transfer price.

Full details of the calculations of the substitution indicators are shown in Appendix A.68.

Table 4.122: Substitution impact indicators for residential heating in Australia

Option	Residential heating	
Feedstock	NG→BlC	NG→CSG
Technology	Ducted gas Ducted air conditioning	Ducted gas
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	- 9.41E-10	- 1.14E-10
Acidification Potential (ADP)	+ 1.92E-09	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 2.04E-09	- 3.93E-09
Particulate Matter Formation (PMF)	+ 2.58E-10	- 9.29E-11
Freshwater Withdrawal (FWW)	+ 8.40E-11	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 1.44E-08
Saline Water Generation (CWG)	+ 1.60E-11	- 7.17E-13
Solid Waste Generation (SWG)	+ 1.75E-07	+ 6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised capital costs	+ 767.0	-
Cash operating costs	+ 100.0	- 145.0
Total operating costs	+ 867.0	- 145.0

Legend: '+' sign denotes increase in impacts, '-' sign denotes decrease in impacts, NG=Natural Gas, BlC=Black Coal, CSG=Coal Seam Gas, Cogen=Cogeneration, IGCC=Integrated Gasification and Combined Cycle

Note: Environmental impact indicators include upstream and downstream impacts

4.8. SUMMARY OF RESULTS

Substitution impact indicators have been calculated for baseload and peaking grid electricity, mining, ammonia production, alumina and nickel refining and residential heating. The indicators show the change in environmental and economic impacts as a result of substitution of natural gas with black coal, diesel and CSG in the appropriate sectors. The environmental impact indicators have been normalised against Australian emissions to enable comparison at an equal basis and to identify the impact category with the most significant change in the Australian context. The economic impact indicators show the additional capital and operating cost burdens or benefits that result from the substitution.

For each specific sector, it can be seen that substitution with black coal or diesel will result in an increase in environmental impacts with some exceptions, with the latter occurring due to either higher impacts in the natural gas upstream section or the effects of offsetting emissions from electricity generation. Substitution with black coal or diesel will result in an increase in economic impacts for all sectors. This is mainly due to the high capital cost of black coal-based plants or the high price of diesel feedstock. Compared with black coal and diesel, substitution with CSG resulted in more negative substitution impact indicators with the exception of associated water withdrawal and solid waste generation.

This chapter looked at the impacts of substitution of natural gas with alternatives in each Australian sector studied at an individual level. The following chapter will further develop the methodology to combine all the results from Chapter 4 to enable an analysis of natural gas substitution at a national level. This analysis will then give a bigger picture of the full consequences of natural gas scarcity in Australia.

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Chapter 5

System-wide Analysis

5.1. OVERVIEW

In the previous chapter, impacts resulting from natural gas substitution were studied for grid electricity generation, mining, ammonia manufacturing, alumina and nickel refining, and residential heating in Australia. In this chapter, the substitution impact data from Chapter 4 is used to model the impacts of natural gas scarcity for the whole of Australia. The implications of substitution with different alternative fuels are examined, and a sensitivity analysis studies the factors that drive the impacts of substitution.

5.2. PURPOSE OF THE SYSTEM-WIDE ANALYSIS

The classical LCA methodology models the environmental impacts associated with an individual product and allows comparison of the same product produced with different feedstock. However, where multiple products are concerned, the LCA methodology examines each product individually, making them isolated from one another even though they share the same resource (i.e. natural gas). In reality, a natural gas scarcity will affect not just a single user, but all natural gas consumers within the economy. As Figure 1.2 shows, a wide range of Australian sectors directly consume natural gas, indicating that a natural gas scarcity will impact all these sectors. Thus, a system wide analysis is required to capture the full impacts of natural gas scarcity in Australia.

5.3. BASE CASE: NATURAL GAS USE IN AUSTRALIA (2012)

The first step in the system-wide analysis is to generate a model that represents current natural gas usage in Australia, which is referred to as the base case. A snapshot of the whole natural gas system in Australia is shown in Figure 5.1, including the subsectors covered in Chapter 4. Due to the large variety of sectors and subsectors, it is necessary to represent a whole sector using one or two key specific subsectors (e.g. OCGT and CCGT for grid electricity generation). For grid electricity generation, mining, manufacturing and residential heating, it was necessary to represent the whole of each sector this way. Extrapolation of data will be required to include the remaining subsectors in each sector, and also to include other sectors in the system-wide analysis.

To facilitate the calculations, it was assumed that all the natural gas users had a common pipeline supply and therefore its composition and the energy content was the same (provided in Section 4.1.4).

5.3.1. GRID ELECTRICITY GENERATION

CCGT technology is chosen to represent natural gas usage for baseload electricity generation while OCGT technology is chosen to represent natural gas usage for peaking electricity generation. 85% of natural gas usage in the grid electricity generation sector has been represented using these two gas technologies and the remaining 16% of natural gas was consumed in steam turbine (ST) technology (see Appendix A.21). ST technologies are mainly used for peaking electricity generation and run on capacity factors lower than 28%, examples of which include the Newport power station in Victoria

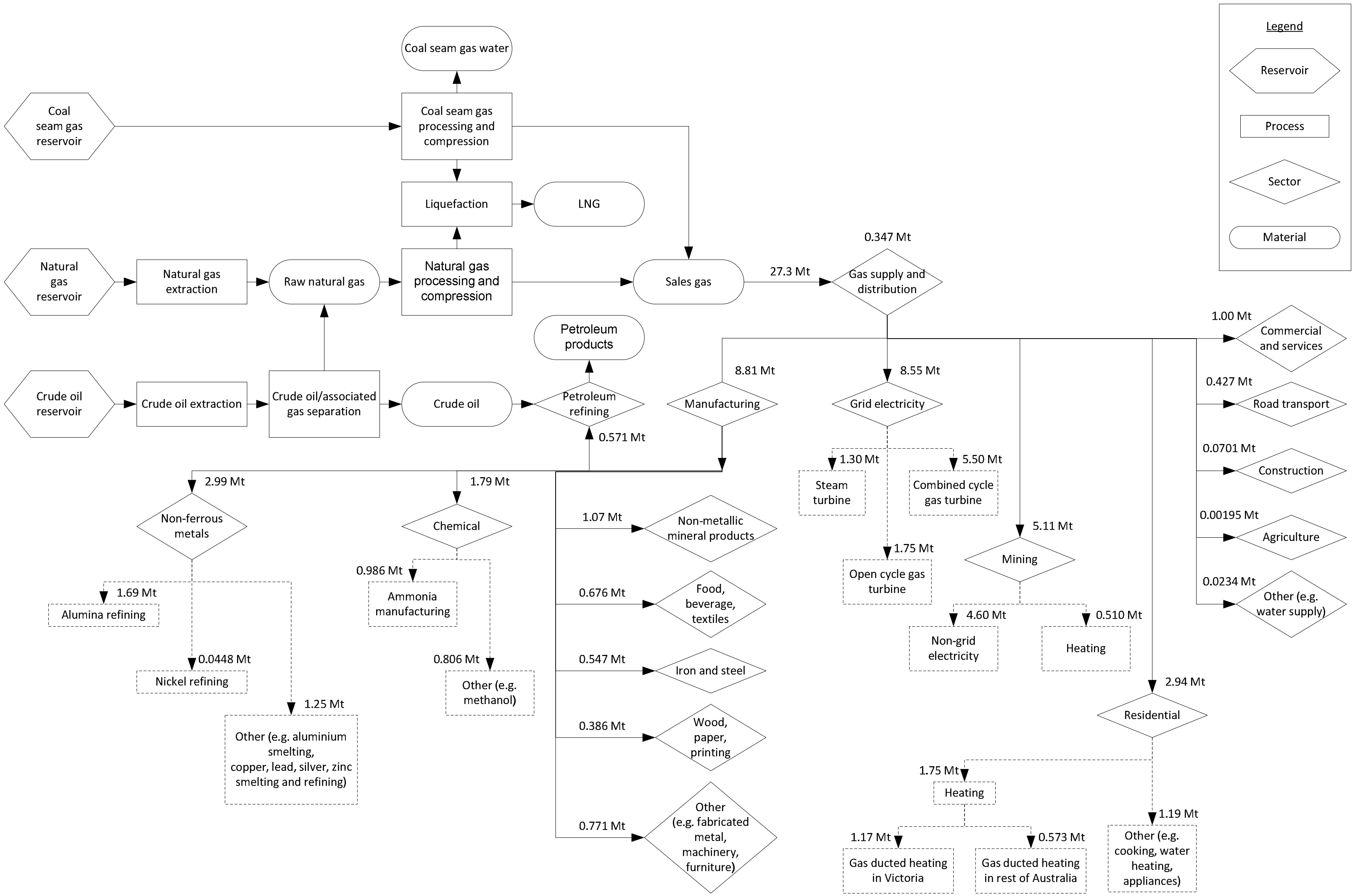

Figure 5.1: Flow of natural gas from extraction of raw materials to final sectoral use.

Note: The natural gas usages reported in Mt (x10^6 t) were adapted from 2011 figures (BREE 2013e). The dotted lines and boxes represent beakdowns of individual sectors based on author's assumption.

and Torrens Island power station in South Australia (Picaro et al. 2002, AEMO 2013). Since ST grid electricity generation is largely used for peaking purposes in Australia, it was assumed that the impacts from natural gas consumed can be adequately modelled using OCGT peaking electricity data. In reality, the impacts of ST lie between those of OCGT and CCGT (May & Brennan 2006). Thus, all natural gas consumption in the grid electricity sector can be adequately represented by CCGT and OCGT using Equation 5.1.

$$\text{Impacts}_{\text{Grid Electricity}} = \text{Impacts}_{\text{CCGT}} + \text{Impacts}_{\text{OCGT}}\left(\frac{1.75+1.30}{1.75}\right) \qquad (\text{Equation 5.1})$$

5.3.2. MINING

While one or two dominant natural gas users were chosen to represent each major natural gas usage sector in Australia, the natural gas consumption in the mining sector was assumed to be completely accounted for by either non-grid electricity generation or heating as shown in Equation 5.2. As discussed in Chapter 4.4, the ratio between non-grid electricity generation and heating was assumed to be 9:1. Because of this assumption, coupled with the large share of natural gas consumed in the mining sector, the natural gas used to generate non-grid electricity for the mining industry was found to be significantly high with respect to natural gas consumption in the whole of Australia (i.e. nearly 17% of total consumption). This reflects the significant number of isolated mines with no access to grid electricity that depends on natural gas for supply of electricity and heating.

$$\text{Impacts}_{\text{Mining}} = \text{Impacts}_{\text{Off-grid Electricity}} + \text{Impacts}_{\text{Heating}} \qquad (\text{Equation 5.2})$$

5.3.3. MANUFACTURING

The manufacturing sector is the biggest natural gas user in Australia and is made up of many smaller subsectors. Two subsectors were chosen to represent the whole manufacturing sector: Non-ferrous metals and chemicals. In 2012, more than 54% of the natural gas consumption in the manufacturing industry was attributed to both these subsectors combined.

The dominant natural gas user in the non-ferrous metals subsector is alumina refining which requires steam, electricity and high temperature heating (e.g. calcination). Included in this subsector are many other non-ferrous metals (e.g. nickel, copper, silver, lead and zinc) where natural gas consumption is relatively minor in their respective manufacturing processes. As discussed in Chapter 4.6, many of these metals exist as sulphide ores and the exothermic nature of smelting sulphides reduces the amount of fuel required. Out of these non-ferrous metals, nickel refining was selected for analysis due to the use of natural gas both for steam and power generation and also for chemicals manufacturing. As discussed in Chapter 4.6, the calcination process in alumina refining limits the choice of fuel to natural gas and nickel refining requires H_2, H_2S and NH_3 which are all derived from natural gas. Thus, both alumina and nickel refining are highly dependent on natural gas as compared to the other non-ferrous metals and are estimated to consume 58% of natural gas usage in the non-ferrous metals subsector. The remaining natural gas (i.e. 42%) was consumed in other non-ferrous metals, which were estimated by extrapolating the alumina and nickel refining data so that the whole non-ferrous metals subsector were fully represented by alumina and nickel. This is shown in Equation 5.3.

$$\text{Impacts}_{\text{Non-ferrous Metals}} = \left(\text{Impacts}_{\text{Alumina Refining}} + \text{Impacts}_{\text{Nickel Refining}}\right)\left(\frac{2.99}{1.69+0.0448}\right) \quad (\text{Equation 5.3})$$

As for the chemicals sector, more than half of natural gas consumed in the chemicals sector was used to produce ammonia (i.e. 55%). The remaining 45% of natural gas usage was consumed to produce other chemicals which were not examined in the analysis (e.g. ethylene, sodium cyanide and methanol). These other chemicals were estimated by extrapolating the ammonia data using Equation 5.4, thus fully representing the chemicals sector using ammonia.

$$\text{Impacts}_{\text{Chemicals}} = \left(\text{Impacts}_{\text{Ammonia}}\right)\left(\frac{1.79}{0.986}\right) \quad (\text{Equation 5.4})$$

The remaining subsectors which consumed 46% of natural gas in the manufacturing sector were estimated by extrapolating the non-ferrous metals sector and chemicals sector data using Equation 5.5. Using this method, impacts across the entire manufacturing sector can be estimated using data from alumina refining, nickel refining and ammonia production.

$$\text{Impacts}_{\text{Manufacturing}} = \left(\text{Impacts}_{\text{Non-ferrous Metals}} + \text{Impacts}_{\text{Chemicals}}\right)\left(\frac{8.81}{2.99+1.79}\right) \quad (\text{Equation 5.5})$$

5.3.4. RESIDENTIAL HEATING

In Chapter 4.7, it was shown that 60% of natural gas consumed in the Australian residential sector was in gas heating, of which the state of Victoria had the largest share (83.7%). The environmental impacts of gas heating will be the same in other states, and it was assumed that the economic impact data can be extrapolated from the Victorian data to represent all states in Australia. As for natural gas usage in other residential applications, the end use will involve combustion processes similar to that to provide heating energy (principally cooking and water heating). It can then be assumed that the data for residential heating can be extrapolated to include these other residential usages of natural gas. Thus, the whole residential sector is adequately represented using Victorian residential heating data as shown in Equation 5.6.

$$\text{Impacts}_{\text{Residential}} = \left(\text{Impacts}_{\text{Victorian Residential Heating}}\right)\left(\frac{2.94}{1.17}\right) \quad (\text{Equation 5.6})$$

5.3.5. REMAINING NATURAL GAS USAGE SECTORS

The remaining sectors of natural gas usage including commercial and services, transportation, construction, agriculture and gas supply and distribution were not modelled in Chapter 4. The natural gas consumed in all these minor sectors amounted to 6.85% of total consumption across Australia. To account for these usages, the natural gas consumption data were extrapolated from all four major sectors using Equation 5.7.

$$\text{Impacts}_{\text{Natural Gas System}} = \begin{pmatrix} \text{Impacts}_{\text{Grid Electricity}} + \text{Impacts}_{\text{Mining}} \\ + \text{Impacts}_{\text{Manufacturing}} + \text{Impacts}_{\text{Residential}} \end{pmatrix} \left(\frac{27.3}{25.4} \right) \qquad \text{(Equation 5.7)}$$

5.3.6. MODELLING OF THE NATURAL GAS USAGE BASE CASE

Figure 5.2 shows the final representation of Australia's total 2012 natural gas usage using the extrapolated data from the systems studied in detail in Chapter 4. It can be seen that CCGT has the highest share of total natural gas usage (5.79 Mt), closely followed by alumina refining (5.76 Mt).

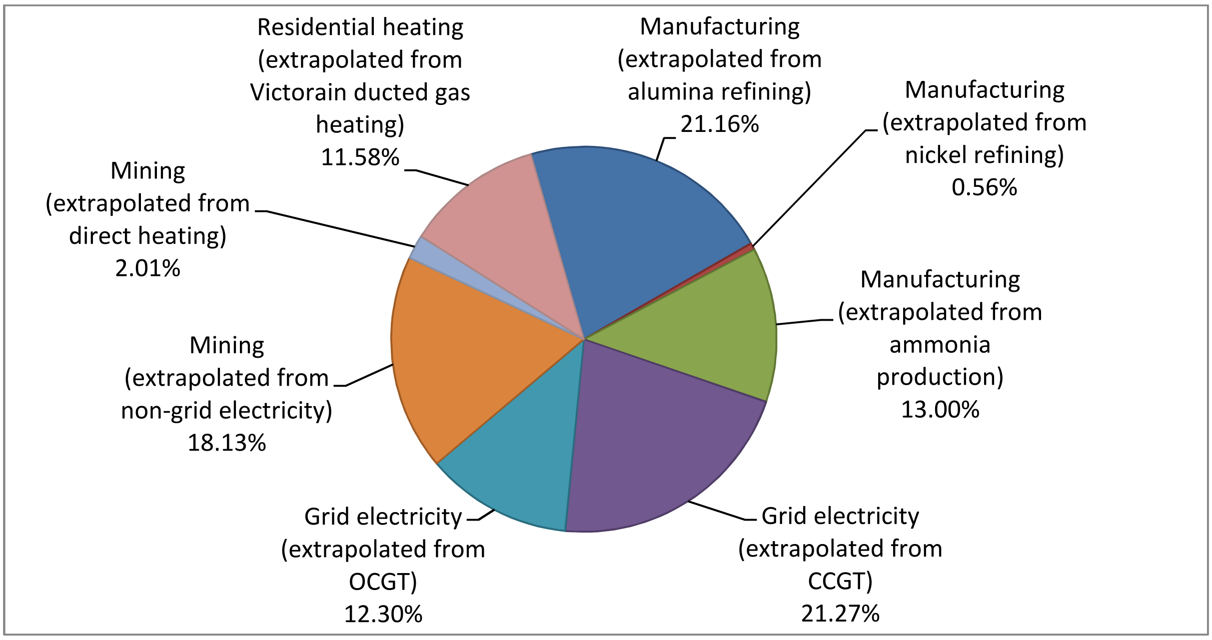

Figure 5.2: Extrapolated 2012 natural gas usage model for Australia with the contributions of systems studied in detail and their percentages.

Using the natural gas usage model in Figure 5.2, the environmental and economic impact indicators can now be calculated for the whole natural gas system of Australia.

5.3.6.1. ENVIRONMENTAL IMPACT INDICATORS

This section looks at the environmental impact indicators for the natural gas base case. These indicators include air emissions (i.e. global warming, acidification, photochemical oxidation, and particulate matter), water withdrawal, water emissions, and solid emissions. which were covered in Chapter 4. Under each category, the environmental impact indicators have been normalised and given a basis of 'yr/t natural gas consumed'. Further explanation on the normalisation method can be found in Section 4.1.2.4 and in Appendix A.1.

According to Figure 5.3, the emission to air categories, namely GWP, ADP, POP and PMF, have high normalised scores. GWP and POP both have the highest normalised score out of the four while PMF recorded the lowest. This indicates that the sectors covered in this analysis contribute significantly to the greenhouse gas and photochemical oxidation emissions in Australia but have little contribution to the release of particulates to the atmosphere.

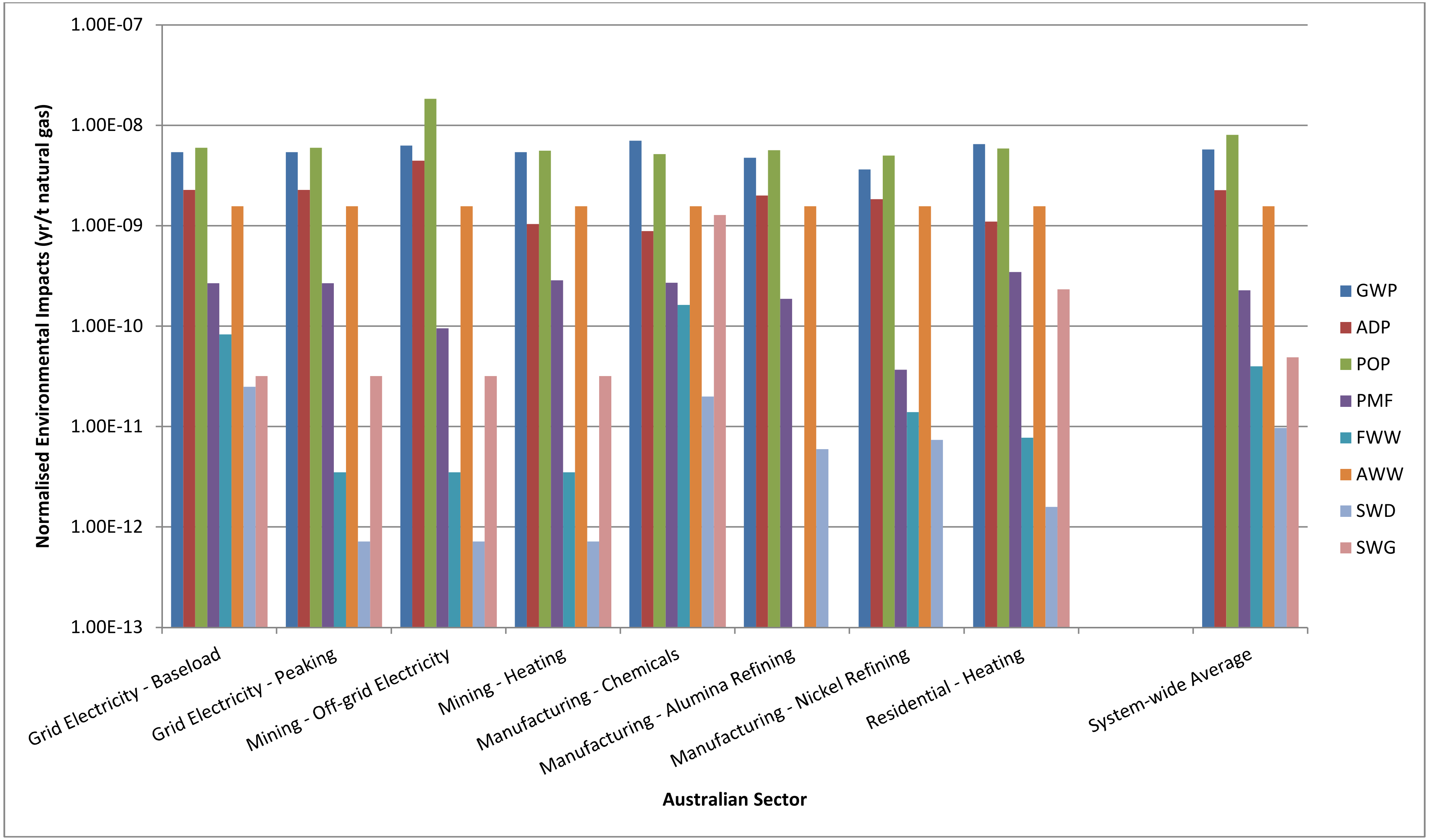

Figure 5.3: Normalised environmental impact indicators for base case of natural gas consumption in Australia (includes both upstream and downstream impacts). Note: Negative values do not appear on the logarithmic scale graph.

The AWW impacts for the natural gas system in Australia are shown to be significantly high for natural gas systems. The AWW value is identical across all sectors as associated water withdrawal originates from the natural gas extraction and purification stage, which was then carried over into the downstream sections.

The FWW, SWD and SWG scores are identical for the mining sector and the peaking grid electricity generation sector as there were no water and solid waste impacts in the downstream sections. These impacts also originate from the natural gas upstream section. The chemicals manufacturing sector and residential sector consume indirect electricity, which is reflected in the high SWG scores. On the other hand, the non-ferrous metals manufacturing sector produces export electricity, resulting in a negative SWG score.

Tabulated data for Figure 5.3 is located in Appendix A.69.

5.3.6.2. ECONOMIC IMPACT INDICATORS

This section covers the economic impact indicators derived for the natural gas usage base case, which is divided into the capital cost impact indicator and the operating cost impact indicator. Costs are measured separately for the upstream and downstream sections; the distribution costs have not been included in this analysis but may become significant over long distances. All costs are reported in 2012 Australian dollars.

The capital investment in natural gas-related plants for a single sector can be obtained by multiplying the capital cost of a single plant unit of selected capacity with the equivalent number of plants required for the sector[***]. By adding together the non-annualised capital investment for all sectors and extrapolating the data to include the remaining sectors not studied, it was estimated that the capital worth of Australia’s natural gas system is approximately $76 billion in total. The largest capital cost incurred is the upstream sector, which required more than $20.5 billion in capital expenditure to extract and process all natural gas required for Australia’s natural gas system.

To obtain the capital cost impact indicator for each sector, the capital investment is annualised into units of ‘A$/t natural gas’. This produces an indicator that measures the capital repayment needed for a brand new plant for every t natural gas consumed. Figure 5.4 shows the annualised capital cost for all sectors, including the system-wide average. For downstream sections, Figure 5.4 shows that the peaking grid electricity generation sector and the residential sector have among the highest annualised capital costs relative to natural gas consumed. This is due to the overall large number and small size of both OCGT power stations (compared to baseload power stations) and residential heaters. Another factor is the low availability of both systems, where peaking power stations generally run at 10% availability and residential heaters run only during cold seasons. Thus, when divided by the low amount of natural gas consumed, the annualised capital cost indicator results are relatively high. On the other hand, the mining sector has the lowest annualised capital costs relative to natural gas consumed because of the relatively low capital costs and high availability of gas turbines and boilers. In general, OCGT systems in off-grid electricity generation operate at a higher availability (e.g. 85%) as compared to OCGT systems in peaking power generation (e.g. 10%). The system-wide average for annualised capital costs was approximately $275 for every t natural gas consumed.

[***] The equivalent number of plants was calculated by dividing the total natural gas consumed with the natural gas input of a single plant of a scale suitable for all feedstock options. This will often produce a non-integer, which is used for the purpose of calculating accurate values for the total capital cost.

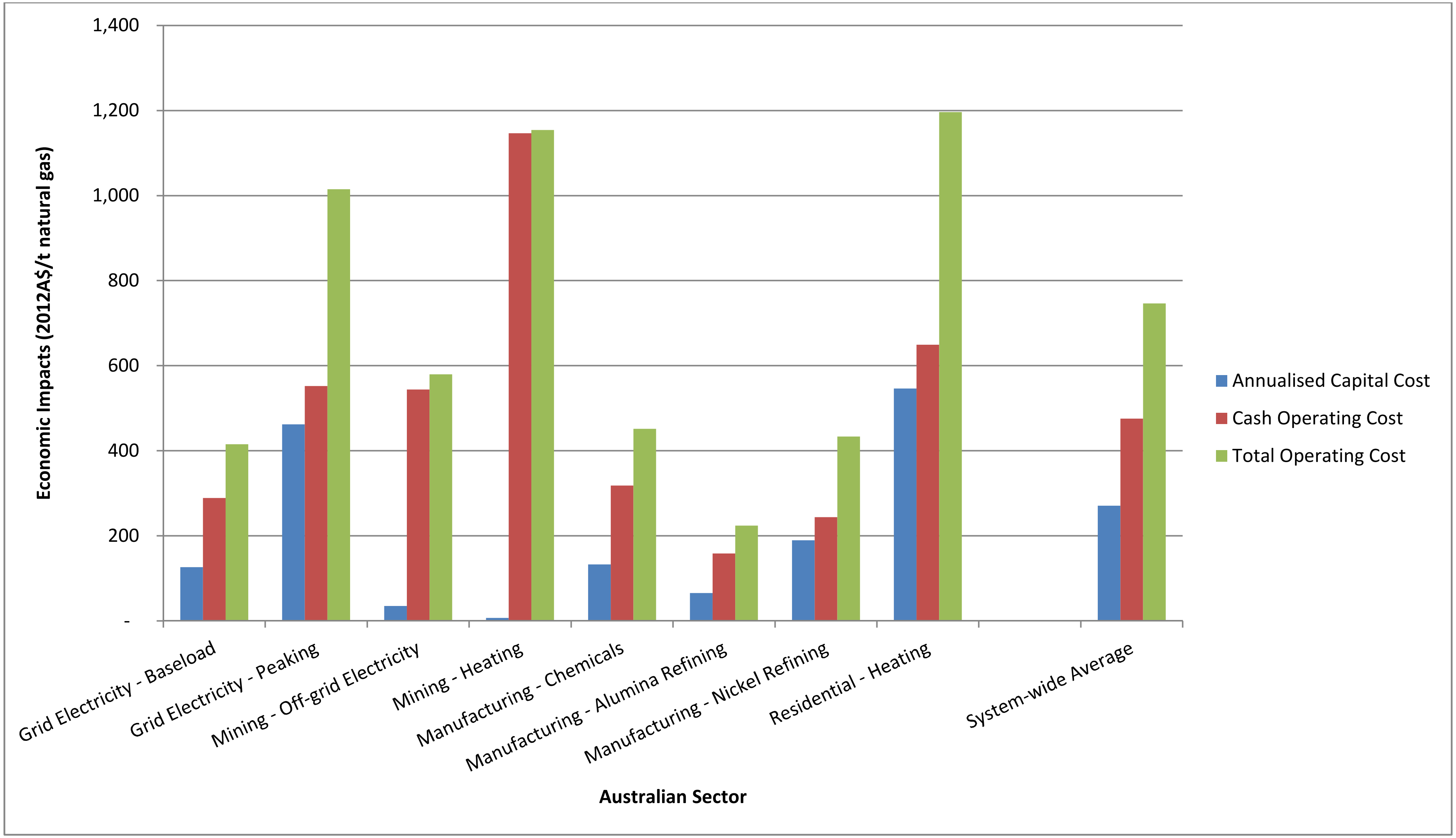

Figure 5.4: Capital and operating cost indicators for base case of natural gas consumption in Australia.

Note: Total operating costs are the sum of annualised capital costs and cash operating costs.

The operating cost impact indicator is the sum of the cash operating cost and the annualised capital cost per tonne of natural gas consumed. The operating costs for the natural gas extraction and purification, together with a resource royalty tax, are carried over as a transfer cost into the fuel cost component of the downstream cash operating cost. The transfer cost for natural gas was covered separately in Section 4.2.2. The residential sector and the peaking grid electricity sector reported the highest cash operating cost per t natural gas. This was due to the low efficiencies of the ducted gas heating systems and the OCGT power stations. The mining sector also reported high cash operating costs which is attributed to the inefficiencies of the gas engines and heaters and the constant usage of natural gas. The non-ferrous metals manufacturing sector can potentially reduce its cash operating cost by generating export electricity to sell. Larger scale plants such as ammonia plants and CCGT power stations benefit from lower operating costs due to economies of scale. Economies of scale can also be seen when comparing the annualised capital cost of a 29 kW residential heater ($546/t natural gas) with that of a 10 MW industrial boiler ($7.46/t natural gas). The cash operating cost of the system-wide analysis was calculated to be $477 per t natural gas consumed, while the sum of the cash operating cost and the annualised capital cost for the system-wide analysis was estimated to be $752 for every tonne of natural gas consumed. When combined, the total operating costs for the residential sector and the peaking grid electricity generation was recorded to be the highest due to the high annualised capital costs and cash operating costs.

Tabulated data for Figure 5.4 is located in Appendix A.70.

5.4. BASE CASE: SUBSTITUTION WITH BLACK COAL OR DIESEL

In this scenario of natural gas scarcity, conventional natural gas resources have been rapidly depleted until the point where they become too expensive or unavailable. This section will focus on the environmental and economic impacts that occur as a result of this scarcity and subsequent substitution to either black coal or diesel.

5.4.1. SUBSTITUTION OF NATURAL GAS WITH BLACK COAL

This section examines the substitution of natural gas with black coal in the following sectors: baseload electricity generation, non-ferrous metals manufacturing, chemicals manufacturing and residential consumption. The first three of these sectors rely on economies of scale to maximise output and minimise costs. Residential heating is highly distributed and substitution would involve grid-based electricity.

The mining sector and peaking grid electricity generation were excluded for black coal. Black coal was not considered for the mining sector because of widely distributed activities often located remotely. As for peaking grid electricity generation, black coal systems are unable to respond to peaking power demand with sufficient speed.

5.4.1.1. ENVIRONMENTAL SUBSTITUTION IMPACT INDICATORS

The environmental impact indicators for this section and subsequent sections are different to that covered in Chapter 5.3 as these substitution indicators show the difference between the black coal and the natural gas case instead of the absolute impacts of the black coal case. The upstream environmental impacts that arise as a result of substitution of natural gas with black coal are first calculated separately from the downstream sections. For the upstream section, it is necessary to calculate the equivalent amount of black coal to replace the total natural gas consumed system-wide in order to calculate the full upstream impacts of the substitution. Details of the environmental impact indicators are found in Appendix A.71.

According to Figure 5.5, SWG is the largest impact caused by substitution of natural gas with black coal. Open cut coal mining produces overburden, which is a form of degrading the land and is considered a waste in this analysis, therefore giving black coal extraction and purification a significantly large SWG score. All sectors have negative AWW scores as black coal systems have a lower AWW score than natural gas in the upstream section. The POP scores for all sectors are also negative due to higher VOC and fugitive emissions from the natural gas upstream section as compared to the black coal system. The residential sector has a negative GWP because of the high efficiency of the reverse pump heating system as compared to a gas burner system. The sector with the most negative scores after substitution is the alumina refining sector due to its ability to export electricity. The only increases recorded for this subsector are in GWP, PMF and SWG. Overall, substitution of natural gas with black coal will result in significant increases in solid waste generation and emissions to air in Australia, but will produce negative photochemical oxidation and associated water withdrawal indicator scores.

5.4.1.2. ECONOMIC SUBSTITUTION IMPACT INDICATORS

The economic impact indicators represent increases or decreases in capital and operating costs due to the substitution of natural gas with black coal. Unlike environmental impacts and operating cost impacts which can be substituted between different fuels, capital costs are sunk costs which cannot be recovered[†††]. For example, capital spent on a gas-based system cannot be substituted with that of a coal-based system. Therefore, the annualised capital cost indictor in this case summarises the new capital investment required to construct greenfield coal-based plants to replace existing but non-operational natural gas plants due to a natural gas scarcity. When the non-annualised capital investment in black coal-related plants is added up across all sectors, the total was found to be $119 billion. Without adequate capital available, a complete substitution to a black coal system will potentially become economically non-viable. Figure 5.6 shows that the greatest increase in annualised capital costs occur in the nickel refinery utility system, followed by the residential sector. This is attributed to the high capital costs required to produce steam, electricity, chemicals for the nickel refinery, as well as the high capital cost and large numbers of reverse cycle ducted systems required for the substitution. The system-wide annualised capital cost was calculated to increase by $430 per t natural gas substituted, which is more than 170% that of the natural gas system.

The cash operating cost indicators in Figure 5.6 indicate the change in operating costs after the substitution. Despite the savings in fuel costs due to the lower transfer price of coal as compared to natural gas, all sectors recorded increases in cash operating costs. This was largely due to the much higher capital-related costs for black coal processes. The increases in annualised capital costs were much larger than for the cash operating costs, thus showing the significant effect of the high capital costs of black coal processes. The highest increases in cash operating costs were observed in the mining heating and nickel refining sector, but the share of natural gas in these two sectors were relatively low and had little effect on the weighted average of the operating costs for the black coal system. The system-wide average of the operating cost impact increases was approximately $86 per t natural gas substituted.

Overall, complete substitution to black coal was expected to result in an overall increase of total operating costs by $516 per tonne of natural gas substituted. To summarise, the black coal system will incur a large capital cost penalty and will have higher running costs than the natural gas system. Details of the economic impact indicators are found in Appendix A.72.

5.4.2. SUBSTITUTION OF NATURAL GAS WITH DIESEL

This section will examine the substitution of natural gas with diesel in the sectors where black coal was deemed impractical, namely the mining sector and peaking electricity generation. Diesel provides a convenient but expensive substitute for natural gas, given that its transfer price was $20/GJ as compared to natural gas with a transfer price of $3.50/GJ.

[†††] It is possible to recover some capital through the salvaging of materials at the end of the plant life. This will only be a minor portion of the original capital investment.

5.4.2.1. ENVIRONMENTAL SUBSTITUTION IMPACT INDICATORS

The environmental impact indicators in this section represent the difference between the diesel case and the natural gas case. The upstream environmental impacts that arise as a result of substitution of natural gas with diesel are calculated separately from the downstream sections. Similar to the black coal case, the system-wide data for natural gas is required to calculate the amount of diesel necessary to replace natural gas. 1 t natural gas can be substituted by 1.14 t diesel or 1.25 t crude oil. In Figure 5.5, the emissions to air were found to be the most significant of all the environmental impact indicators for substitution with diesel. The water impacts and solid waste generation are constant for all sectors where diesel is used. This is due to the fact that there are negligible substitution impacts within these categories in the upstream section, and the impacts are carried over from the upstream section into the downstream sections. Details of the environmental impact indicators are found in Appendix A.73.

5.4.2.2. ECONOMIC SUBSTITUTION IMPACT INDICATORS

Figure 5.6 details the changes in annualised capital costs and cash operating costs when natural gas is substituted with diesel. Unlike the black coal system, the cash operating costs for the diesel system significantly exceed that of the annualised capital costs. This is due to the high diesel fuel cost. A total of $6.46 billion worth of capital investment in new diesel plants is required for the substitution. When annualised, this gives a system-wide average of $77.6 per t natural gas substituted. In contrast, the weighted average cash operating cost of the whole diesel system was found to be $1,030 per t natural gas substituted. The mining heating sector recorded the lowest increase in total operating costs, whereas mining off-grid electricity generation had the highest increase. Details of the economic impact indicators are found in Appendix A.74.

5.4.3. COMBINED SYSTEM-WIDE SUBSTITUTION ANALYSIS

Figure 5.5 shows that the overall effect of substitution is an increase in system-wide environmental impacts per t natural gas substituted. The overall system-wide indicators are largely dictated by black coal. Hence, when compared to the Australian annual emissions, the system-wide indicators show that SWG has the most significant increase and AWW is the only decrease recorded. All four emissions to air categories remain relatively significant, while the two water-related impacts are less so.

Thus, for a scenario where natural gas supply has been rapidly depleted, the option to use black coal and diesel to replace lost production will have serious environmental and economic consequences across Australia, ranging from an increase in greenhouse gas emissions, freshwater depletion and solid waste generation, to an upfront expenditure estimated to be $126 billion and a subsequent inflation in operating costs by approximately $680/t natural gas substituted. These costs represent a substantial burden to society should the substitution cases examined be necessary.

Details of the environmental and economic impact indicators are found in Appendices A.75 and A.76.

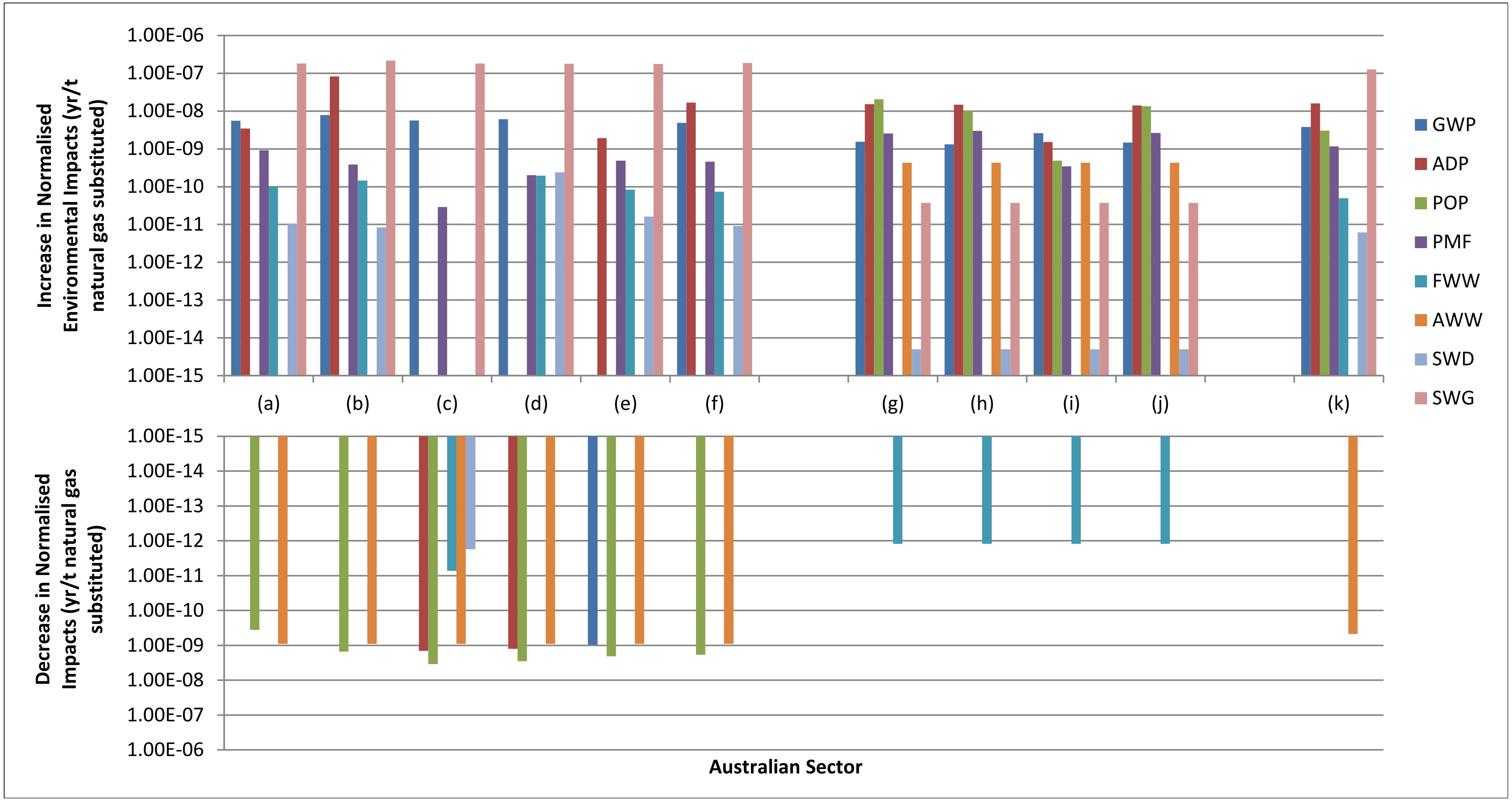

Figure 5.5: Normalised environmental impact indicators for substitution of natural gas with black coal in (a) baseload grid electricity, (b) chemicals, (c) alumina refining, (d) nickel refining and (e) residential heating, and with diesel in (g) peaking grid electricity (h) off-grid electricity in mining (i) and heating in mining. (f) is the average for black coal systems, (j) is the average for diesel systems and (k) is the weighted avergae for all sectors.. Upstream and downstream impacts included.

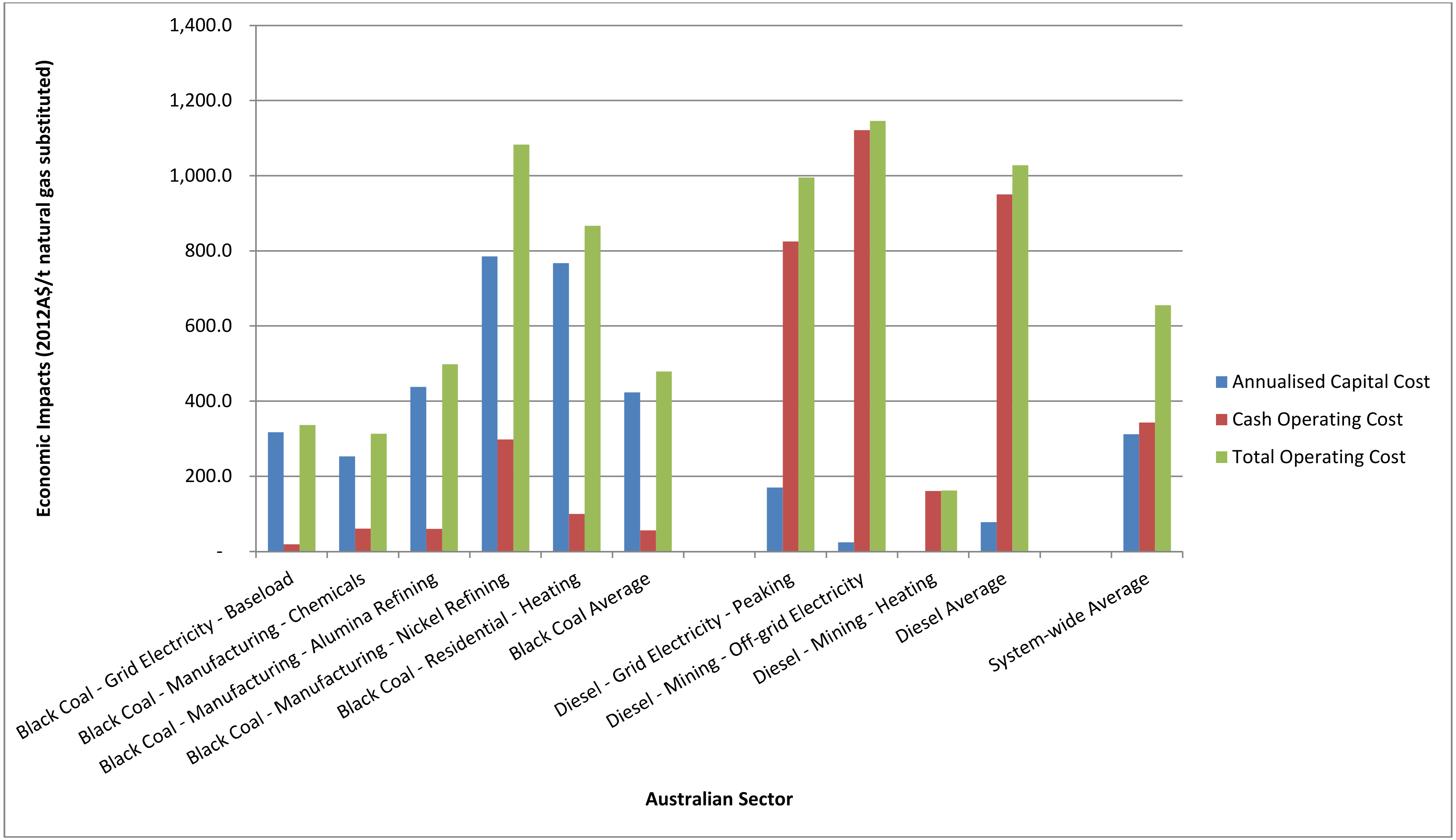

Figure 5.6: Capital and operating cost indicators for substitution of natural gas with black coal and diesel in Australia.

Note: Total operating costs are the sum of annualised capital costs and cash operating costs.

5.5. BASE CASE: SUBSTITUTION WITH CSG

The second scenario of natural gas scarcity is similar to the first where conventional natural gas resources have been depleted and CSG was chosen as a substitute. CSG is similar in nature to conventional natural gas and can be used in many of the existing gas pipelines, thereby avoiding the purchasing of additional capital investment for new downstream process plants. This section will focus on the environmental and economic impacts that occur as a result of substitution to CSG.

5.5.1. ENVIRONMENTAL SUBSTITUTION IMPACT INDICATORS

Substitution with CSG will not result in any change in environmental impacts in the downstream sections due to the assumption that natural gas and CSG have the same properties at the pipeline exit. Instead, most of the impacts from substitution to CSG occur in the upstream section.

The substitution of natural gas with CSG resulted in a decrease in many impact categories. Figure 5.7 shows the negative substitution impact indicators and their magnitudes. It can be seen that the greatest decrease in impacts lie in the emissions to air categories (GWP, ADP, POP, PMF), followed by the freshwater withdrawal (FWW) and saline water generation (SWG) categories.

Substitution of natural gas with CSG will also result in major increases in two impact categories. The only two positive substitution impact categories are AWW and SWG as shown in Figure 5.8. AWW is also the indicator with the highest magnitude out of all environmental impact categories for this substitution case. This reveals that there is a significant trade-off if CSG is chosen as the substitute for natural gas. Both AWW and SWG impacts are attributed to the large amounts of CSG water produced simultaneously together with CSG. As explained in Chapter 4.2.4, the salt produced from reverse osmosis and evaporation of the leftover brine is considered a solid waste because there are high concentrations of impurities and metals in the salt, which limit the beneficial uses of the salt by-product.

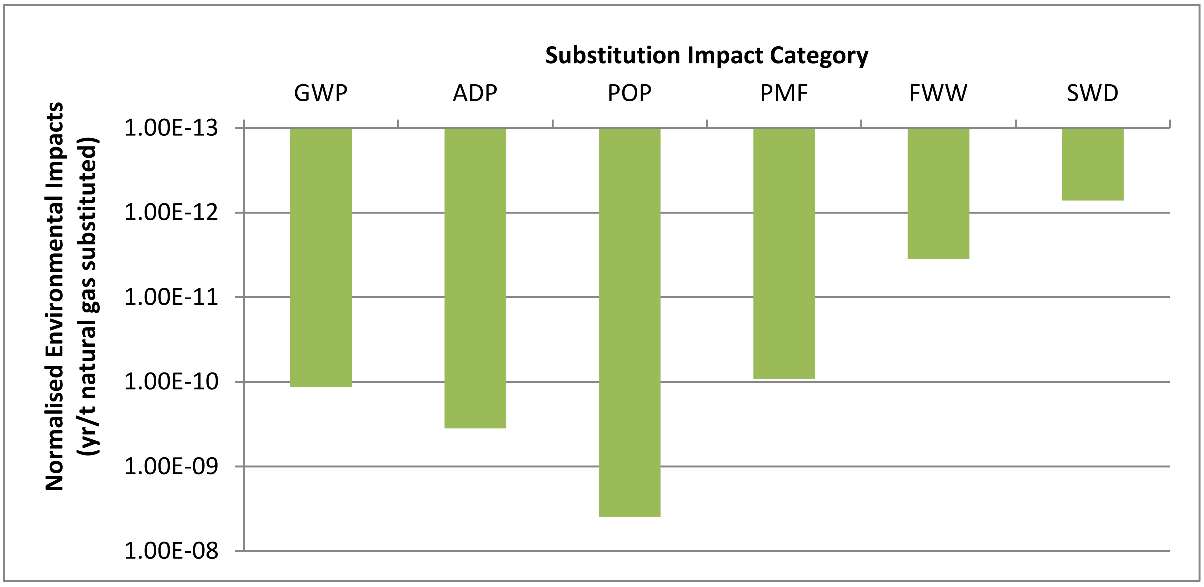

Figure 5.7: Normalised environmental impact indicators for base case substitution of natural gas with CSG in Australia (originally with negative signs denoting decrease in impacts)

Figure 5.8: Normalised environmental impact indicators for base case substitution of natural gas with CSG in Australia (originally with positive signs denoting increase in impacts)

Details of the environmental impact indicators are found in Appendices A.77.

5.5.2. ECONOMIC SUBSTITUTION IMPACT INDICATORS

The economic impacts of substituting natural gas with CSG are minimal. compared with previous substitutions as shown in Figure 5.9. The upstream capital and operating costs are incorporated into the transfer price of natural gas and CSG, which are included in the cash operating costs for the downstream sections. There is no change in the annualised capital costs in the downstream section because of the assumption that natural gas and CSG are able to share the same pipeline and plant infrastructure without any modifications required. Hence, the only change in economic substitution impacts is the cash operating costs in each downstream process. Decreases were reported for all sectors because of the lower transfer price of CSG ($2.70/GJ) compared to natural gas ($3.50/GJ). However, there is inherent uncertainty in the prices of CSG and natural gas due to the various factors covered in Chapter 4.

The upstream processes of the CSG system are different to that of conventional natural gas, e.g. CSG involves onshore production while natural gas is mostly produced offshore. Therefore, the total capital investment may be different for natural gas and CSG upstream sections. After closer inspection, the difference in upstream capital investment were found to be relatively small for the systems that were studied (i.e. $21.5 billion for CSG compared to $22 billion for natural gas).

At a glance, CSG seems to be a favourable substitute both environmentally and economically for conventional natural gas when supplies have been rapidly depleted. However, the environmental impact indicators have revealed that one of the weaknesses of CSG as a substitute is the increase extraction of CSG water, which will have consequences for the land and the landowners. This implication will be discussed in further detail in Section 5.7.

Details of the environmental impact indicators are found in Appendices A.78.

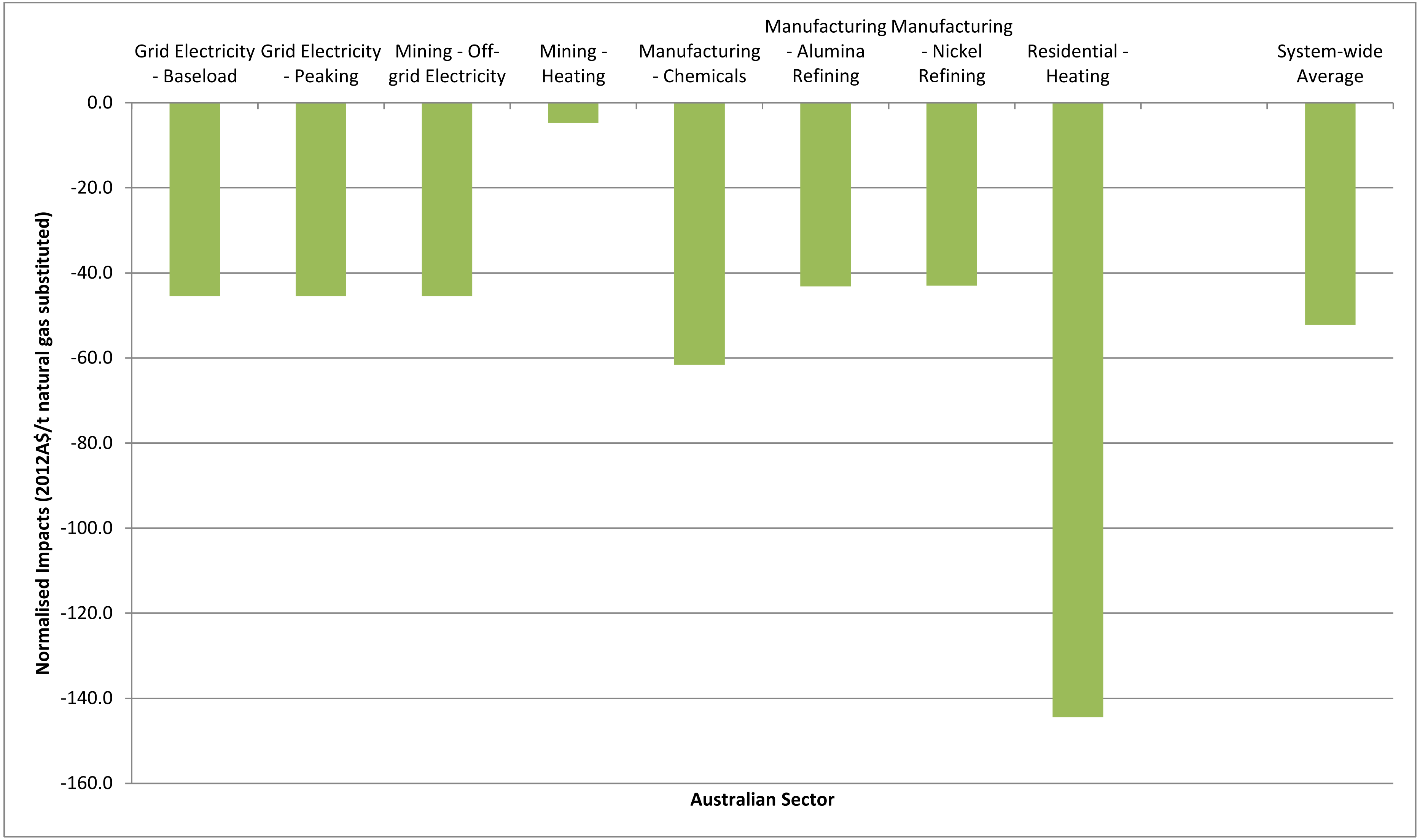

Figure 5.9: Operating cost indicators for substitution of natural gas with CSG in Australia.

5.6. SENSITIVITY ANALYSIS

For this analysis, assumptions and simplifications were made to facilitate the modelling of the natural gas system's environmental and economic impacts as well as that of the alternatives. This section will look at variations in these assumptions to examine their influence on the environmental and economic impacts for the system-wide case as well as for individual products.

5.6.1. VARIATION IN NATURAL GAS EXTRACTION COST

In this analysis, the assumption was that all conventional gas was extracted offshore and processed onshore. Natural gas offshore extraction costs can vary depending on the type of hydrocarbons extracted, extraction capacity, distance from shore and depth of facility to seabed. These variations will have an effect on the natural gas extraction cost, which in turn will affect the natural gas transfer price.

A sensitivity analysis is performed for a natural gas extraction facility with a higher capital cost to reflect the higher costs required to access the natural gas. The 75 PJ/yr Macedon gas project in the Pilbara, Western Australia, was chosen as a high cost reference. The project costs $1.5 billion and includes four offshore production wells that services the Macedon field about 100 km off the north west coast of Western Australia, and an onshore gas treatment plant at Onslow.

The capital cost of the gas processing plant is adjusted from the capital cost of the Devil Creek gas processing plant[‡‡‡] using Equation 4.5 to account for the reduction in facility size.

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad \text{(Equation 4.5)}$$

The remaining capital costs were attributed to the offshore wellhead and related equipment. The extraction operating costs were assumed to remain the same as that for the Devil Creek project (See Section 4.2.2). The processing plant operating cost was modified according to the capacity and capital cost of the Macedon gas processing plant. Table 5.1 shows that an increase in capital expenditure for natural gas extraction of nearly 43% will raise the total operating cost, and subsequently the transfer price, by 23%. This will have a flow-on effect on downstream costs. For this study, the effects on total system-wide operating costs and on the price of natural gas products will be examined.

[‡‡‡] The Devil Creek gas processing plant has a capacity of 78 PJ/yr capacity and has a capital cost of $280 million (See Chapter 4.2.2)

Table 5.1: Influence of natural gas extraction costs on transfer price (Costs are expressed in 2012A$)

	Units	Base case (Devil Creek)	High capital cost case (Macedon)	Increase(+%)/ decrease(-%)
Capital cost	2012A$million	1,050	1,500	+ 42.9%
Total operating cost [a]	2012A$/t	159	196	+ 23.3%
	2012A$/GJ	3.10	3.81	+ 23.2%
Transfer price [b]	2012A$/t	179	220	+ 22.9%
	2012A$/GJ	3.48	4.28	+ 22.9%

[a] Total operating costs are the sum of cash operating costs and annualised capital costs.

[b] The transfer price is the sum of the total operating cost and the royalty cost (see Chapter 4.3.2).

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table 5.2 shows that an increase in transfer price of natural gas by 23% will cause the total system-wide operating costs for the natural gas base case will rise by $2.5 billion in annual costs (+12.7%). This rise in operating costs will cause the cost penalty of the substitution case with black coal and diesel to be decrease by $1.6 billion (-8.55%), and the cost credit of the substitution case with CSG to increase by $1.39 billion (-97.3%).

Table 5.2: Influence of natural gas extraction costs on system-wide total operating costs for natural gas base case and substitution cases (Costs are expressed in 2012A$)

Total operating costs [a]	Base case (Devil Creek)		High capital cost case (Macedon)		Increase(+%)/ decrease(-%)
	2012A$million	2012A$/t natural gas	2012A$million	2012A$/t natural gas	
Natural gas base case	20,400	746	22,900	841	+ 12.7%
Substitution with black coal and diesel	+ 17,900	+ 655	+ 16,300	+ 599	- 8.55%
Substitution with CSG	- 1,430	- 52.2	- 2,820	- 103	- 97.3%

[a] Total operating costs are the sum of cash operating costs and annualised capital costs.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table 5.3 shows the effect of an increased transfer price of natural gas on three selected natural gas products: baseload grid electricity, ammonia and residential heating. Baseload electricity prices from natural gas will rise by $6.40/MWh (+11.3%), prices of ammonia from natural gas will rise by $27/t NH_3 (+9.71%) and the average residential annual gas heating bill will rise by $220 (+12.6%). The cost penalty of substitution with black coal will decrease for each case, and the cost credit of substitution with CSG will double.

Table 5.3: Influence of natural gas extraction costs on selected natural gas product costs and substitution costs (Costs are expressed in 2012A$)

Category	Units	Base case (Devil Creek)			High capital cost case (Macedon)		
		Natural gas base case	Substitution with black coal	Substitution with CSG	Natural gas base case	Substitution with black coal	Substitution with CSG
Baseload grid electricity generation cost [a]	2012A$/ MWh	56.6	+ 28.6	- 6.19	63.0	+ 22.2	- 12.5
Ammonia production cost [a]	2012A$/ t NH_3	256	+ 106	- 35.8	283	+ 79.1	- 63.0
Annual residential heating cost [a]	2012A$/ yr	1,750	+ 473	- 211	1,970	+ 257	- 427

[a] Costs represent total operating costs which are a sum of cash operating costs and annualised capital costs.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

In summary, the harder and more expensive it is to extract and process natural gas, the higher the cost of natural gas becomes. This has the effect of increasing the cost of products derived from natural gas, making products derived from black coal, diesel and CSG more competitive in price.

5.6.2. VARIATION IN WELLHEAD GAS COMPOSITION

The properties and composition of Australian wellhead gas can vary depending on the resource location. These variations are among the many factors that affect the environmental impacts and the capital and operating costs of natural gas processing. These can include:

- High or low carbon dioxide content
- High or low ethane content
- High or low nitrogen content
- High or low sulphur content
- Presence of entrained water, mercury and other impurities

An analysis was performed on the effects of carbon dioxide content on the environmental and economic impacts of natural gas. The natural gas extracted from three different natural gas reservoirs in Australia were examined: Ballera, Timor Sea and Bass Strait. The compositions of these three natural gas feedstocks as found at the wellhead are shown in Table 5.4.

Table 5.4: Wellhead composition of natural gas in different locations across Australia (Brennan 2012)

Location	Ballera	Timor Sea	Bass Strait
Pressure (kPag)	8,000	31,000	7,000
Temperature (°C)	60	135	23
Composition (mol%)			
Methane	62	71	80
Ethane	10	7.4	7
Propane	3.7	4.6	4.4
i-Butane	0.6	1.2	0.9
n-Butane	1.1	1.7	1.2
i-Pentane	0.3	0.8	0.6
n-Pentane	0.4	0.6	0.6
C6+	2.6	4.1	2.3
N2	1.6	3.4	0.7
CO2	17.9	5.5	2.1
Total	100	100	100
Water	Saturated	Saturated	Saturated
Hydrogen sulphide	30 ppm	20 ppm	60 ppm

Wellhead gas must be purified in processing plants to meet sales gas specifications. Natural gas processing plants were modelled using HYSYS to purify each natural gas stream. Information such as CO_2 removed and energy consumption were extracted from the models. Detailed calculations can be found in Appendix A.79.

5.6.2.1. IMPACT ON GREENHOUSE GAS EMISSIONS

The Ballera field is seen to have the highest CO_2 content of all three natural gas reservoirs, followed by Timor Sea and Bass Strait. A carbon dioxide balance was modelled for the processing plant purifying natural gas from each reservoir. The CO_2 emissions were gathered from three sources:

- CO_2 removed from the petroleum stream by an acid gas removal system
- CO_2 released from combustion in gas turbines to supply power to the processing plant
- CO_2 created by flaring of gas at the wellhead

The CO_2 emissions resulted from a processing facility that processes both natural gas and petroleum liquids. The CO_2 emissions were divided among the natural gas and petroleum products exiting the processing facility according to the mass of each product. The result of the CO_2 balance can be seen in Table 5.5.

Table 5.5: Carbon dioxide (CO_2) balance in processing plants for different natural gas feedstock compositions

	Ballera	Timor Sea	Bass Strait
Gas and liquids in (t)	1.00	1.00	1.00
Processed natural gas out (t)	0.484	0.551	0.615
Petroleum liquids out (t)	0.253	0.356	0.351
CO_2 from acid gas removal (t)	0.248	0.0813	0.0296
CO_2 from gas turbine (t)	0.0253	0.0267	0.0351
CO_2 from flaring at wellhead (t)	0.00857	0.00959	0.0107
Total CO_2 emissions (t)	0.281	0.117	0.0744
CO_2 allocated to natural gas on mass basis (t)	0.185	0.072	0.049
CO_2 emissions (t/t processed natural gas)	0.382	0.129	0.0772

Based on the three natural gas feedstock provided, the carbon dioxide emissions from the extraction and processing of natural gas can range from 0.0772 to 0.382 t/t processed natural gas. The carbon dioxide emission attributed to the upstream section in Chapter 4.4.1 was 0.255 t CO_2/t processed natural gas, which is within the range in Table 5.5. This CO_2 emission profile was assumed to represent the base case. The lower range of 0.0772 t CO_2/t natural gas (corresponding to 2.1% mole CO_2) was used to represent the low CO_2 case while the upper range of 0.382 t CO_2/t natural gas (corresponding to 17.9% mole CO_2) was used to represent the high CO_2 case.

Table 5.6 shows the effect of CO_2 variations in the raw natural gas on the greenhouse gas emissions in the upstream section and for the overall system inclusive of all sectors outlined in Chapter 5.2. It can be seen that CO_2 emissions from the gas processing plant make up a significant portion of the natural gas upstream greenhouse gas emissions. High CO_2 content in natural gas will cause the greenhouse gas emissions from the natural gas upstream section to be higher, resulting in a smaller penalty for switching to black coal and diesel, and a larger credit for substitution with CSG. The natural gas upstream greenhouse gas emissions varies between 40%-56%, while the overall impact on the system-wide greenhouse gas emissions is less significant (i.e. 5.4%-7.1%) due to the relatively small contribution of the upstream processes to the overall impacts over the product life cycle.

Table 5.6: Effect of natural gas CO_2 content (low, high and base case) on greenhouse gas emission indicators

Category	Units	Natural gas base case			Black coal and diesel case			CSG case		
		Low CO_2	Base case	High CO_2	Low CO_2	Base case	High CO_2	Low CO_2	Base case	High CO_2
Upstream CO_2 emissions	t CO_2/t natural gas processed	0.0772	0.255	0.382						
Upstream greenhouse gas emissions	t CO2-e/t natural gas substituted	0.138	0.316	0.443	- 0.00544	- 0.108	- 0.182	+ 0.116	- 0.0623	- 0.189
Overall system (inclusive of all sectors extrapolated) greenhouse gas emissions	t CO2-e/t natural gas substituted	2.97	3.14	3.27	+ 2.17	+ 2.08	+ 2.01	+ 0.116	- 0.0623	- 0.189

Note: + sign for black coal, diesel and CSG represent an increase relative to natural gas base case, while - sign represents a decrease relative to natural gas base case

5.6.2.2. IMPACT ON CAPITAL AND OPERATING COSTS

The variation of the CO_2 content in the three natural gas feedstocks will affect the economics of the upstream section as shown in Table 5.7. The changes will occur at the amine sweetening unit which removes CO_2 from the natural gas. For a high CO_2 stream, more electrical power will be required by the amine pump to handle a larger circulation flow and more reboiler fuel and cooling water will be required. A larger amine sweetening unit will be required to handle the larger amine circulation flow. Thus, a high CO_2 content will increase the overall capital cost and operating cost of the project.

Table 5.7: Sweetening material flow balance (Mass flow rates are based on 1 t processed natural gas)

	Ballera	Timor Sea	Bass Strait
DEA solution circulated (m^3/t natural gas)	2,903	1,116	804
Electricity (MWh/t natural gas)	7.66	2.95	2.12
Reboiler fuel (GJ/t natural gas)	813	312	225
Cooling water (m^3/t natural gas)	12,800	4,910	3,537
DEA solution makeup (t/t natural gas)	3.53×10^{-5}	3.74×10^{-5}	4.25×10^{-5}

The influence of CO_2 content in natural gas on the capital cost of the natural gas processing plant is shown in Table 5.8. Based on the range of CO_2 content (2.1-17.9 mol%), the capital cost range will be between \$267 million to \$291 million. This change is mainly due to the different sizes of the amine sweetening unit in the gas processing plant.

Table 5.8: Influence of natural gas CO_2 content (low, high and base case) on gas processing plant capital cost (Costs are expressed in 2012A\$million)

	Low CO_2 case	Base case	High CO_2 case
Amine sweetening unit	10.8	14.0	30.2
Total capital cost	259	276	292

Table 5.9 shows the effects of a variation in CO_2 content on the total operating costs in various stages in the analysis. The first section examined the gas processing plant only. Cooling water costs for the natural gas processing plant will increase with higher CO_2 content in the natural gas, and this leads to higher operating costs overall. The electricity costs for the sweetening section will increase with higher CO_2 content, but the HYSYS models show that the electricity requirements for a different section of the gas processing plant (i.e. hydrogen product compression) will be lower, thus giving an overall decreased electricity demand. The percentage change can be relatively low, but when translated into annual costs, these can become significant. For instance, for high CO_2 content, the cooling waste annual costs will increase by 60.4%.

Table 5.9: Influence of natural gas CO_2 content (low, high and base case) on gas processing plant operating cost (Costs are expressed in 2012A$)

	Low CO_2		Base		High CO_2	
	2012A$ million/yr	2012A$/t natural gas	2012A$ million/yr	2012A$/t natural gas	2012A$ million/yr	2012A$/t natural gas
Electricity	9.96	7.67	9.15	7.04	9.10	7.01
Cooling water	1.37	1.05	3.23	2.48	5.18	3.99
Total operating cost	30.3	23.3	32.4	24.8	35.1	27.0

Table 5.10 shows that the range of CO_2 content of natural gas (2.1-17.9 mol%) will result in a natural gas transfer price range of \$3.18/GJ - \$3.29/GJ. The effect appears to be relatively small.

The system-wide results in Table 5.11 show that natural gas with high CO_2 content will result in a \$200 million increase in total annual operating costs for Australia's natural gas system. This increase is only 0.98% when compared to the total operating cost recorded by the Australia's natural gas system.

When looking at selected natural gas products, variations in CO_2 content of natural gas have a minor effect on production costs. Table 5.12 shows that natural gas with high CO_2 content will cause the cost of baseload grid electricity generated from natural gas to rise by \$0.40/MWh (+0.7%), the cost of ammonia to rise \$1/t NH_3 (+0.7%), and the average residential annual gas heating bill to rise by \$10 per year (+0.6%).

Table 5.10: Influence of natural gas CO_2 content (low, high and base case) on natural gas transfer price (Costs are expressed in 2012A$)

	Low CO_2 case		Base case		High CO_2 case	
	2012A$/GJ natural gas	2012A$/t natural gas	2012A$/GJ natural gas	2012A$/t natural gas	2012A$/GJ natural gas	2011A$/t natural gas
Transfer price	3.45	177	3.48	179	3.53	181

Table 5.11: Influence of natural gas CO_2 content (low, high and base case) on system-wide total operating costs for natural gas base case and substitution cases (Costs are expressed in 2012A$)

Total operating costs [a]	Low CO_2 case		Base case		High CO_2 case	
	2012A$ million/yr	2012A$/t natural gas	2012A$ million/yr	2012A$/t natural gas	2012A$ million/yr	2012A$/t natural gas
Natural gas base case	20,300	742	20,400	746	20,500	752
Substitution with black coal and diesel	+ 17,900	+ 658	+ 17,900	+ 655	+ 17,800	+ 652
Substitution with CSG	- 1,370	- 50.1	- 1,430	- 52.2	- 1,510	- 55.3

[a] Total operating costs are the sum of cash operating costs and annualised capital costs.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table 5.12: Influence of natural gas CO_2 content (low, high and base case) on selected natural gas product costs (Costs are expressed in 2012A$)

Category	Units	Low CO_2 case			Base case			High CO_2 case		
		Natural gas base case	Substitution with black coal and diesel	Substitution with CSG	Natural gas base case	Substitution with black coal and diesel	Substitution with CSG	Natural gas base case	Substitution with black coal and diesel	Substitution with CSG
Baseload grid electricity generation cost [a]	2012A$ /MWh	56.4	+ 28.8	- 5.93	56.6	+ 28.6	- 6.19	57.0	+ 28.2	- 6.56
Ammonia production cost [a]	2012A$ /t NH_3	255	+ 107	- 34.6	256	+ 106	- 35.8	257	+ 105	- 37.4
Annual residential heating cost [a]	2012A$ /yr	1,740	+ 482	- 203	1,750	+ 473	- 211	1,760	+ 460	- 224

[a] Costs represent total operating costs which are a sum of cash operating costs and annualised capital costs.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case.

5.6.3. INFLUENCE OF MARKET FORCES

The indicators from Chapter 4 show that the natural gas options for each sector have an advantage over coal-based technologies. This assessment was based on estimated transfer prices which excluded the effect of market forces on prices. However, market forces could influence the purchased prices of natural gas and the costs of the downstream products. Lewis et al. (Lewis et al. 2009) reported Queensland CSG price projections showing new gas contract prices at the wellhead will increase significantly due to the influence of LNG developments, e.g. from $4/GJ in 2010 to between $6-$7/GJ in 2026. The influence of LNG developments will also have the same impact on conventional natural gas prices. For example, in the case where natural gas liquefaction plants are still under construction and there is an oversupply of gas, the price of natural gas will drop. Another possible scenario is when the price of natural gas approaches the netback price of LNG (i.e. the market price received for LNG minus the transport, marketing and liquefaction costs) because LNG exports provide gas producers with an alternative to domestic supply.

A sensitivity analysis is performed for scenarios where the price of natural gas is doubled (from $3.50/GJ to $7/GJ) and tripled (from $3.50/GJ to $10.50/GJ) due to the influence of market prices of LNG. Table 5.13 shows that when the natural gas price is doubled, the users of Australia’s natural gas system will experience more than $6.8 billion increase in total annual operating costs. When the natural gas price is tripled, the total annual operating costs rises above $13.6 billion. Increases in natural gas prices will cause the difference between the total operating costs between black coal and natural gas to decrease until they break even. The entire coal-based system will only break even with natural gas (i.e. total operating costs per t natural gas are equal) once the transfer price of natural gas reaches $12.80/GJ. As for CSG, the cost credit for the substitution from natural gas will increase even further with a growing natural gas price. However, the same market forces that affect natural gas will affect CSG too as more CSG resources are locked into LNG export contracts. The substitution could imply new major capital investment.

Table 5.4 shows that the effect of increasing natural gas price due to market forces will cause the costs of natural gas products to increase, making products derived from black coal more economically attractive. Some natural gas products will break even at lower natural gas prices than others. The cost of baseload grid electricity from black coal will break even when natural gas prices reach $7.20/GJ. For ammonia, this happens when the price of natural gas reaches $6.70/GJ and for residential heating, this is when natural gas reaches a price of $5.25/GJ. This can potentially indicate which sector is preferred to substitute natural gas with black coal. e.g. the usage with the lowest breakeven price is given priority to substitute with black coal. In the scenarios examined, market prices for coal are unaffected by market prices for natural gas.

Table 5.13: Influence of natural gas transfer price on system-wide total operating costs for natural gas base case and substitution cases (Costs are expressed in 2012A$)

Total operating costs [a]	Base case transfer price ($3.48/GJ)		Double transfer price ($6.96)		Triple transfer price ($10.4)	
	2012A$million/ yr	2011A$/t natural gas	2011A$million/ yr	2011A$/t natural gas	2011A$million/ yr	2011A$/t natural gas
Natural gas base case	20,400	746	27,200	996	34,000	1,250
Substitution with black coal and diesel	+ 17,900	+ 655	+ 11,200	+ 410	+ 4,470	+ 164
Substitution with CSG	- 1,430	- 52.2	- 7,470	- 274	- 13,500	- 496

[a] Total operating costs are the sum of cash operating costs and annualised capital costs.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table 5.14: Influence of natural gas transfer price on selected natural gas product costs (Costs are expressed in 2012A$)

Category	Units	Base case transfer price ($3.48/GJ)			Double transfer price ($6.96)			Triple transfer price ($10.4)		
		Natural gas base case	Substitution with black coal and diesel	Substitution with CSG	Natural gas base case	Substitution with black coal and diesel	Substitution with CSG	Natural gas base case	Substitution with black coal and diesel	Substitution with CSG
Baseload grid electricity generation cost [a]	2012A$ /MWh	56.6	+ 28.6	- 6.19	84.0	+ 1.24	- 33.5	111	-26.1	- 60.8
Ammonia production cost [a]	2012A$ /t NH_3	256	+ 106	- 35.8	374	-11.4	- 153	491	- 129	- 271
Annual residential heating cost [a]	2012A$ /yr	1,750	+ 473	- 211	2,680	- 461	- 1,140	3,620	- 1,390	- 2,080

[a] Costs represent total operating costs which are a sum of cash operating costs and annualised capital costs.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

5.6.4. SUMMARY OF SENSITIVITY ANALYSIS

Three variables were explored in this section: Natural gas extraction cost, natural gas wellhead composition and the influence of market forces. All three will affect the transfer price of natural gas and the effects are carried over into the downstream product costs. Table 5.3 and Table 5.12 showed that the capital costs of natural gas extraction have a larger influence on natural gas transfer price than the composition of the natural gas at the wellhead. Both studies reveal the implication of extracting natural gas resources that are harder to extract, resulting in higher capital costs, and are of lower quality, e.g. higher CO_2 content.

Table 5.4 also reveals that the breakeven prices may potentially be helpful to choose a preferred priority for replacement of natural gas.

5.7. IMPLICATIONS OF NATURAL GAS SCARCITY

This section will examine the various impacts of natural gas scarcity and substitution to alternative fuels, which are based on the findings from this chapter, and their environmental and economic implications to Australia.

Implication #1: Substitution of natural gas with black coal and diesel will result in high environmental and economic costs

The major impacts of substitution with black coal and diesel lie in increased emissions to air, increased water impacts and increase solid waste generation as shown in Figure 5.5.

Australia's GHG emissions from black coal combustion were approximately 110 Mt CO_2-e/yr in 2012, of which 99.8% was used for electricity generation (Department of the Environment n.d.). Substitution with black coal in baseload grid electricity generation, the manufacturing sector and the residential sector will cause an increase in annual GHG emissions of by 49.6 Mt CO_2-e/yr . In short, the total GHG from black coal consumption in Australia will increase by nearly 50% as a result of the substitution. Substitution with diesel in peaking grid electricity generation and the mining sector will increase the annual GHG emission further by 7.09 Mt/yr.

Substitution with black coal and diesel will increase the concentration of acidic substances in the air, which can flow into the soil through rainfall and accelerate soil acidification. Soil acidification (pH decline) can lead to reduced agricultural productivity in the short term and irreparable subsurface acidification. 70% of Australian land area is classified as desert and semi-desert, indicating that land suitable for agricultural activities are limited (2014).

Substitution with both fossil fuels will also increase photo-oxidants in the air, leading to increased smog formation. Although the POP for substitution with black coal was negative, the POP for substitution with diesel was positive and higher in magnitude. Exhaust emissions from transportation vehicles are a major source of photochemical oxidation emissions, but natural gas consumption in the road transport sector (e.g. compressed natural gas or LNG fuelled vehicles) is very small compared with other uses in Figure 5.1 (0.427 Mt/yr) and substitution with black coal and diesel will have minimal impact in this sector. Smog formation is characteristic of pollution in urban areas. However, impacts of increased photo-oxidants in the atmosphere will most likely affect localised areas, e.g. remote mining sites. If the mining site is remote, the photo-oxidant impacts will have minimal impact on the population in general. The communities near the mining sites are more at risk of smog pollution.

The increase in rates of coal mining and coal combustion will increase the rate of fine particle discharge and the areas of impact (e.g. nearby societies and natural habitats). In addition, there will be other impacts not examined in the analysis as a result of the substitution. There will be an increase in toxic emissions from coal combustion, including arsenic, mercury, fluorine, cadmium, lead, selenium and zinc; the extent of this increase will reflect the quality of the additional coal mined. Coal mining will lead to land degradation, which leads to lost opportunity for other beneficial uses of the land such as for agricultural activities. Some authors write about the negative effects of coal mining and burning on human health and society which include lung diseases, workplace fatalities, changes in the social fabric of a region, and mental and stress-related diseases in the inhabitants of the region (Connor et al. 2004, Higginbotham et al. 2010, Castleden et al. 2011).

The combined total capital burden for substituting natural gas…In comparison, the total actual expenditure for the year 2014 for Australia, which includes buildings, structures, equipment, plant and machinery, was reported to be $158 billion (ABS 2014). The capital penalty represents 80% of this total annual expenditure. In practice, replacement plants using alternative feedstocks would be phased in over time to reduce the intensity of the capital burden. The capital for any one project would typically be spent over a one to three year period depending on the nature of the project and the particular feedstock. Nevertheless, the capital burden is still substantial in relation to the annual capital expenditure for the country as a whole.

The increased reliance on black coal will require the construction of more coal-based process plants including steam boiler power plants and ammonia plants. Coal-based plants have longer construction times and longer project lead times when compared with natural gas-based plants. This leads to delays in achievable capacity replacement and increased investment risk due to increased uncertainty and delayed return on investment.

Implication #2: Substitution of natural gas with diesel poses a supply risk

Australia's economic reserves of black coal, recorded at a total of 61,000 Mt as of 2012, can support more than 142 years of production at a constant 2012 production rate of 430 Mt/yr (Geoscience Australia & BREE 2014). When a natural gas scarcity prompts a substitution with black coal in baseload grid electricity generation, the manufacturing sector and the residential sector, this substitution will drive the black coal extraction rate up by an additional 47.3 Mt/yr, shortening the resource life by 14 years. At 128 years remaining, the resource life of black coal is still relatively long when compared to other fossil fuels currently available in Australia.

Despite having a large resource supply base, black coal cannot fully substitute natural gas in all applications, particularly in peaking grid electricity generation and the mining sector. Diesel can be used in the applications which are unsuitable for black coal, but Australia has limited domestic supplies of crude oil and is increasingly reliant on imports to meet demand. As of 2012, 83% of discovered crude oil reserves in Australia have been extracted (2014). Australia was reported to have approximately 5,467 PJ or 118 Mt of demonstrated crude oil reserves in 2012 and crude oil production in 2012 amounted to 13.2 Mt/yr (2014). In comparison, the substitution of natural gas with diesel will increase extraction of crude oil by 11 Mt/yr, which means that crude oil production would nearly double because of the substitution.

As Australia currently imports crude oil products to meet demand, there is a possibility to import the required diesel to replace natural gas in peaking grid electricity generation and mining applications. However, the estimated increase in total operating cost due to substitution with diesel was more than $1,030/t natural gas substituted. This was based on a diesel price of $0.80/litre.

Australia has potential reserves of oil shale, shale gas liquids and light tight oil which could contribute to future oil supply if economic and environmental challenges could be overcome (Geoscience Australia & BREE 2014).

Implication #3: Substitution of natural gas with CSG provides environmental and economic benefits but poses issues with its supply base, CSG water and conflict of interest with landowners

Substitution of natural gas with CSG will increase the CSG production rate by 27.4 Mt/yr. Given that the economic reserves of CSG amounted to approximately 699 Mt in 2012 and CSG 2012 production rates were 5.77 Mt/yr, this will drastically shorten the reserve life to 21 years compared to 121 years prior to the substitution (2014). The rate of CSG production is already set to increase by 24.5 Mt/yr with the development of three CSG to LNG plants (i.e. the Australia Pacific LNG project, the Queensland Curtis LNG project and Arrow LNG project).

The substitution indicators shows that there will be a decrease in emissions to air and capital and operating costs for every t natural gas substituted. However, because CSG extraction produces large amounts of CSG water, there will be an increase in AWW after substitution. The large amounts of water extracted with CSG and treatment options such as deep injection into the subsurface will have a direct impact on the environmental flows of groundwater resources. Potential risks will include depletion and contamination of underground water resources such as the Great Artesian Basin.

In addition, the CSG water contains high concentrations of salt and metals as seen in Table 4.16. The CSG water can be treated by processes such as reverse osmosis, but the treatment consumes a lot of energy (0.6 kWh/m^3 CSG water according to Table A.17 in Appendix A.15) and the residual salty brine needs to be properly disposed. A market needs to be found for the salt product which has many impurities and metals, otherwise it is considered as a solid waste and increases the SWG. Water and salt management will be a critical issue for the CSG case, as well as proper monitoring and mitigation of adverse hydrogeological impacts on subsurface aquifers.

CSG projects generally have lower initial capital expenditure because the reserves are located onshore and are typically at a shallow depth, thus requiring smaller drilling rigs than those required for natural gas. The production can be increased incrementally and ongoing and operating costs are relatively low. However, one environmental risk posed by CSG production is that the risk of methane leaks increases as a higher number of wells are required for CSG production. Methane leaks are a more potent GHG than CO_2 and could become a major contributor to the GHG emissions of CSG production. If mitigated and monitored properly, the impacts may be kept at a low level. Thus far, recent studies have shown the fugitive emissions form shale gas wellheads in the U.S. are relatively low, and fugitive emissions from CSG wellheads in Australia are even lower (Allen et al. 2013, Day et al. 2014).

CSG production companies face competing interests with landowners who are usually farmers. These landowners may restrict or charge for access to the land where the CSG resource is located. One implication of increasing the number of CSG projects is the increased risk of devaluing the land and water resources, potentially causing a change or loss of agricultural production. Additional implications include the conflicts created in local communities between allowing or preventing the extraction of CSG in their land.

Implication #4: A natural gas scarcity will increase conflict between export and local use of natural gas

Natural gas is currently being exported as LNG from Western Australia and from the Northern Territory, and CSG to LNG export projects are underway in New South Wales and Queensland. Currently, projects such as the North West Shelf in Western Australia are under contract to provide natural gas for domestic use. However, liquefying the natural gas and exporting it to the Asian market rather than selling it to domestic users at a cheaper price can make higher profits. This will create pressure of domestic gas prices to rise to match the market price of LNG, threatening the viability of value-adding facilities such as ammonia plants and alumina refineries, as well as increasing costs for domestic users. Thus, tension is created between local users who want cheap gas and LNG companies who want the export the gas at global market prices.

Should natural gas reserves be depleted, more pressure will be placed on CSG to make up the shortfall for both domestic use and export. Similar to natural gas, CSG prices will increase when more resources are locked in LNG export contracts. The competition for gas will increase between local users and exporters as the supply of gas becomes limited. The question shifts from ‘what should the price of gas be?’ to ‘who should get the gas?’.

Black coal and diesel are potential alternatives to alleviate the lack of gas for domestic users, but substitution to these fossil fuels will produce higher environmental impacts and also increase the costs for domestic users as the value-adding facilities require coal- or diesel- based equipment to make up for the natural gas shortfall.

Thus far, the analysis has only looked at the domestic impacts of natural gas scarcity and has not included the LNG case.

Implication #5: A natural gas scarcity will hasten the development of Carbon Capture and Storage (CCS) technology

Australia’s total greenhouse gas emissions at a national level was recorded to be 559 Mt in 2012, including land use, land use change and forestry emissions. Natural gas contributes to maintaining the greenhouse gas emissions in Australia at a low level due to its low emission technologies and usages as compared to black coal and diesel. A natural gas scarcity requiring substitution with black coal and diesel will raise annual greenhouse gas emissions by 56.8 Mt, which is nearly 10% of the 2012 emission level.

The Australian government aims to reduce Australia’s emissions by 5% below 2000 levels (586 Mt CO_2-e) by 2020. Projections have estimated 2020 emissions to reach 685 Mt CO_2-e, requiring a cumulative abatement task of 431 Mt CO_2-e and an abatement task of 131 Mt CO_2-e in 2020 to reach the 2020 target. A scarcity of natural gas will make it more difficult to reach this goal due to the additional 56.8 Mt CO_2-e that needs to be factored into the abatement task.

Carbon capture and storage (CCS) technology becomes crucial under the scenario of substitution of natural gas with black coal and diesel. Current and new coal combustion technologies (based on pulverised coal technologies) are already approaching maximum efficiency and greenhouse gas intensity limits. Further greenhouse gas reduction (higher than 80%) can be achieved through the capture and geologic storage of CO_2. CCS technology has yet to be demonstrated at the scales needed for power plants in Australia, and is likely to decrease the efficiency and add significant costs to the production of electricity. Research and implementation of CCS in practice will require additional capital. Higher capital costs of CCS systems are going to be a disadvantage for the combined black coal and diesel systems, which are already reported to require $126 billion of new capital investment to replace natural gas.

Implication #6: A natural gas scarcity will have minimal impact of Australia's water resources

The substitution of natural gas-based processes with coal-based and diesel-based processes will cause an increase in the extraction and consumption of water supplies from the environment, thus hastening the depletion of water resources. Water is a sensitive issue for Australia due to an average rainfall that is below the global average (469 mm/yr vs 746 mm/yr), the desert or semi-desert climate in 70% of the continent, past frequencies and severities of droughts, and a number of competing uses including agriculture, industry and human consumption.

In 2013, 82,297 GL or 82.3 billion tonnes of water was extracted from the environment for use in the Australian economy (ABS 2013a). Substitution of natural gas with black coal and diesel will increase water extraction rates by nearly 89.8 million tonnes per year, which is approximately 0.1% of current water extraction. It can be observed that approximately 98.1% of water extraction is attributed to electricity, gas, water and waste services (largely due to hydro-electricity generation) and the agriculture sector combined. The hydro-electricity generation and agriculture sectors use little to no natural gas as compared to the other major natural gas consumers. Even when just looking at the total water extraction in mining (799 million tonnes), manufacturing (254 million tonnes), households (151 million tonnes) and grid electricity generation (non-hydro-electricity) (estimated to be 329 million tonnes), the increase in annual water extraction rates is still relatively small (5.86%). This is based on the assumption that all cooling systems in the analysis are recirculated cooling water systems which use evaporative cooling and consume relatively little freshwater.

It can be concluded that when looking at the water depletion profile for the whole of Australia, the substitution of natural gas with black coal and diesel will not result in a significant water depletion impact. However, there may be localised impacts due to water depletion, as water supply is not evenly distributed across Australia.

Implication #7: If not given priority to limited gas supplies, the cost of grid electricity is set to increase

The substitution indicators based on estimated fuel transfer prices show that substitution of natural gas with black coal and diesel will cause the cost of electricity to rise. For residential customers, this will result in higher electricity bills. With the natural gas shortage, residential customers using gas ducted heating will need to bear the capital cost of switching to electrical appliances (e.g. electrical heat pumps) and incur the increased electricity price.

Natural gas has been a crucial fuel used to run peaking open cycle gas turbine power stations. In Australia, peaking power demand is increasing, and because peaking power stations only run occasionally, they charge a higher price per megawatt-hour of electricity than baseload power stations. Without a natural gas supply available, liquid fuels which are more expensive than natural gas, principally diesel, are the only current alternatives available other than a limited amount of hydro-electricity available in southeast Australia to meet peak demand, thus driving up the price of peaking electricity even further.

If the grid electricity generation sector is not able to secure limited gas supplies (e.g. CSG and other sources of gas locked into export contracts), then using black coal and diesel to generate electricity instead of natural gas will result in an overall increase in emissions and costs. This will drive technological change towards other alternatives such as solar and wind for electricity generation. While this could be beneficial, there are currently key challenges that need to be tackled for renewables, such as the low power density as compared to that for fossil fuels (thus requiring more land and materials), their intermittent performance and energy storage provision.

Implication #8: If not given priority to limited gas supplies, the manufacturing sector's importance will diminish

Much of the Australian manufacturing sector relies on cheap natural gas to manufacture goods. The substitution indicators show that a natural gas scarcity causing a substitution to black coal and diesel will potentially cause the price of manufacturing goods (e.g. alumina, nickel and ammonia) to increase. This will result in the loss of competitiveness of the Australian manufacturing sector. The higher costs of value-adding industries will force operations to shift overseas, leading to a loss of employment in Australia. Security of supply of goods will be affected as goods that can be manufactured locally will need to be imported from other countries. These cumulative impacts will threaten the viability of Australia's manufacturing sector.

5.8. PRIORITY USE OF NATURAL GAS

The substitution indicators show the increase or decrease in environmental and cost impacts for each sector. These indicators can be used in conjunction with other criteria to prioritise natural gas usages based on emissions and costs. Possible criteria include added value, ease of substitution including access to substitutes, new capital required, employment and other social factors.

The following analysis demonstrates how the substitution indicators can be used to priotise natural gas sectors. Given that each sector has one total operating cost indicator and eight different environmental indicators, the analysis can use a basis of 'environmental impacts per unit cost'. The changes in environmental impacts due to substitution are plotted against the change in economic impacts due to substitution in a bar chart. The area underneath the graph shows the environmental emissions released per year as demonstrated in Appendix A.80. The impacts of transportation and distribution may affect the results, but these impacts are not considered as part of a simplification in this analysis.

5.8.1. SUBSTITUTION WITH BLACK COAL AND DIESEL

When natural gas is fully substituted with both black coal and diesel, the increase in total operating costs was calculated to be $17.9 billion per year. A 'substitution cost threshold' can be put into effect to determine which sectors will undergo substitution of natural gas. For a substitution cost threshold of $10 billion/yr, for example, substitution of natural gas with black coal and diesel is recommended for the sectors that fall on the left of the substitution cost threshold in Figure 5.10 up until the change in total operating costs reaches $10 billion/yr. In Figure 5.10, the sectors with low or negative

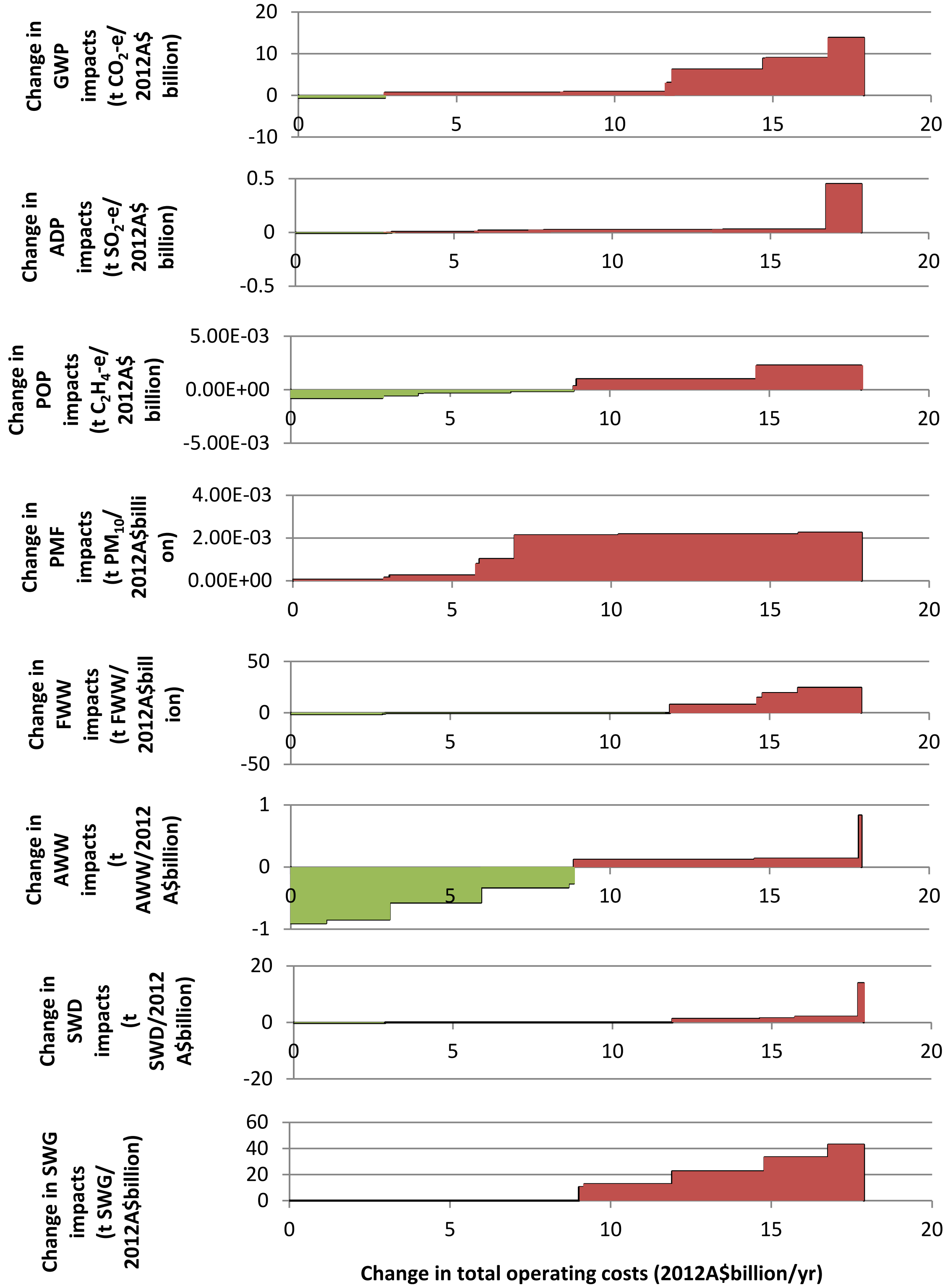

Figure 5.10: Change in environmental impacts against change in total operating costs

environmental impact change are prioritised for substitution because there will an abatement of certain emissions, such as in POP and AWW, in some sectors.

For a substitution cost threshold of $10 billion/yr, the baseload grid electricity generation sector falls to the right of the threshold for all environmental categories except for emissions to air categories ADP and POP. This indicates that substitution of natural gas for black coal is discouraged for this sector.

On the other hand, for the same substitution cost threshold, the residential sector falls to the left of the threshold for all environmental categories excluding water-related impact categories FWW and SWD. For this sector, substitution of natural gas for black coal is recommended to take advantage of the relatively low environmental impacts.

The alumina refining sector has the lowest environmental impact scores per unit cost for many of the categories such as ADP, POP, PM_{10}, FWW and SWD. Because of this, the alumina refining sector has the highest priority for substitution of natural gas with black coal. Conversely, the chemicals manufacturing sector has the highest environmental impact scores per unit cost for GWP, ADP and SWG. This suggests that it is preferable to allocate natural gas to the chemicals manufacturing sector and avoid substitution with black coal. The high impact scores imply the difficulty to produce chemicals from black coal feedstock.

The peaking power generation sector and off-grid electricity generation in the mining sector both fall near the threshold for almost all environmental categories. This suggests that natural gas in these two sectors can be substituted with diesel when the change in total operating costs approaches the substitution cost threshold.

5.8.2. SUBSTITUTION WITH CSG

For CSG, priority is not given based on environmental credits or penalties as these are similar for every downstream process, nor is priority given based on capital costs as no new plants are constructed. Instead, priority for substitution with CSG is given to the sectors based on total operating costs. The residential sector gets the first priority for CSG because it has the largest decrease in operating costs out of all the sectors. The next largest decrease was observed in the chemicals manufacturing sector. Following that, the next sector to receive priority for substitution with CSG is either between baseload grid electricity, peaking grid electricity and off-grid electricity generation. Each of these three sectors has identical drops in operating costs. Alumina refining will be the next to receive priority, followed by nickel heating and then heating in the mining sector.

5.9. LOCATIONAL CONSIDERATIONS

Although the substitution indicators facilitate the choosing of sectors to replace natural gas with alternatives for substitution, the locations of resources and the downstream facilities have an influence in determining the viability of the substitution.

Australia’s fossil fuel resources are concentrated in the different states in Australia and segregated from one another. The majority of Australia’s remaining oil and natural gas reserves lie on the northwest coast of Western Australia and Northern Territory as seen in Figure 4.3. Black coal reserves are mainly found in Queensland and New South Wales as seen in Figure 4.7, while CSG reserves are focused mainly in Queensland and, potentially, New South Wales, as seen in Figure 4.9. Victoria has its own supply of brown coal and natural gas reserves. There is a large geographical gap between the western and eastern gas regions. Currently, there is no exchange of gas between these two regions. Instead, each region consumes and exports its own gas.

The various uses of natural gas are also location-based. Grid electricity consumption is heavily concentrated in the major Australian cities reflecting relative population sizes. Electricity generated for these cities are located near gas or coal sources and are within reasonable distance from the cities. Gas use for residential heating is concentrated in Victoria. Large industrial facilities for chemicals and minerals processing benefit by having all users together in the same location. e.g. Kwinana industrial park. As for mining sites, these are widely dispersed across the land.

When measuring the impacts of natural gas usage and substitution with alternative fuels, these locational considerations have a significant influence. For instance, natural gas transportation and distribution costs will become increasingly significant the further apart are the resource and the demand centres.

5.10. DIFFICULTY OF SUBSTITUTION

Another consideration is the ease of substitution for each of the alternatives to natural gas. CSG is the easiest to substitute for natural gas, as the existing natural gas plants and pipelines can be reused. Diesel can substitute natural gas readily in gas engines and boilers, however minor modifications to the equipment will be required to handle liquid fuel instead of gas and higher operating costs are needed due to the higher level of impurities in diesel. Black coal is the hardest to substitute for natural gas. There are more conversion steps involved with transforming the solid fuel into a more useful form or product; hence the process is less efficient than a process consuming natural gas. For instance, while natural gas can be converted directly into electricity through a gas turbine, black coal requires generation of steam to drive a steam turbine, or the generation of syngas before it is combusted in a gas turbine in order to generate electricity. It is relatively easy to substitute natural gas with black coal in electricity generation as the technology is already established, but it is more difficult for chemicals manufacturing due to the lower hydrogen-to-carbon ratio and the technology is less established. Conversion of solid fuels will create environmental problems such as the release of particulates and heavy metals into the atmosphere, therefore higher capital and operating costs are required for additional cleaning equipment and operations. Renewable energy sources such as solar and wind play an important part in replacing natural gas in electricity generation, but they are unable to provide chemical feedstock such as hydrogen or synthesis gas.

5.11. CONCLUSION

This chapter models impact indicators for the Australian natural gas system and substitution impact indicators for the alternative systems replacing natural gas. The natural gas system is beneficial for Australia because of its low greenhouse gas, acidification and particulate emissions. The natural gas system is competitive in the economic sense due to its generally low capital and operating requirements.

Natural gas scarcity will require choosing the best alternative to replace natural gas. Choosing black coal and diesel as the substitute will result in higher levels of emissions, water impacts (particularly freshwater withdrawal) and solid waste generation (largely due to overburden of coal mining). It partially offsets VOC and methane emissions from natural gas systems, but produces significant amounts of NO_x emissions through combustion. Capital requirements for black coal and diesel systems are higher than for natural gas systems, but can be cost competitive with natural gas if the price of natural gas becomes sufficiently high, either due to increased costs to extract and process lower quality natural gas resources which are harder to get, or because of market forces driving natural gas prices up to match the LNG market price.

On the other hand, CSG may seem the best alternative to replace natural gas as the natural gas downstream plants can be reused. However, significant amounts of CSG water are produced to release the gas and will require proper management. Where previously the impacts of natural gas extraction are offshore, CSG extraction moves the impacts onshore by occupying land to drill the large number of wells required to produce CSG and pose possible changes to the land as well as surface and underground water sources. CSG also faces similar exposure to market forces that will raise its price to match the LNG market price.

The substitution indicators are useful tools to locate priority usages of natural gas. An analysis performed on the changes in environmental impacts and costs due to substitution shows that it is highly recommended to substitute natural gas in the alumina refining sector as the increase in environmental impacts per unit cost is lower than most other sectors. On the other hand, the recommendation for the chemicals manufacturing sector is to avoid substitution of natural gas as the process to produce chemicals from black coal is difficult. Using the substitution cost threshold, it can be seen that the baseload grid electricity generation sector should be allocated natural gas as it lies below the threshold level for most environmental impacts, and substitution with black coal is recommended for the residential heating sector as it lies above the threshold level for most impact categories. The peaking power generation sector and off-grid electricity generation in mining are both low priority with regards to substitution with diesel systems as they lie very near the threshold level. However, consideration must also be given to ease of substitution, access to substitutes and wider social and economic implications.

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Chapter 6

Methodology Review

6.1. OVERVIEW

This chapter reviews the proposed substitution impact methodology by comparing it with other existing resource depletion indicators, highlighting its strengths and limitations and stating recommendations for improvement.

6.2. REVIEW OF EXISTING RESOURCE DEPLETION INDICATORS

In this section, the results obtained using the proposed methodology will be compared with existing resource depletion indicators. This will include the CML method (both 1992 and 2001 versions), the RDI method, the Eco-Indicator 99 method and the ReCiPe 2008 method. A summary of the indicators using the LCI data from Chapter 4 is shown for baseload grid electricity generation in Table 6.1, for peaking grid electricity generation in Table 6.2, and for residential heating in Table 6.3. Many of these indicators are calculated using the LCI data for grid electricity generation and residential heating.

Table 6.1: Summary of resource depletion indicators for baseload grid electricity generation using natural gas and black coal

Resource Depletion Indicator Type	Unit (per MWh)	Feedstock	
		Natural gas	Black coal
CML 1992 method	Dimensionless	4.86×10^{-11}	4.75×10^{-12}
CML 2001 method	t Sb-eq.	3.41×10^{-3}	4.17×10^{-3}
RDI 1998	yr	1.58×10^{-3}	2.27×10^{-3}
Eco-Indicator 99 method (Hierarchist)	MJ surplus energy	619	91.5
Eco-Indicator 99 method (Egalitarian)	MJ surplus energy	367	741
ReCiPe 2008 method (Individualist)	US$(2004)	1,160	1,200
ReCiPe 2008 method (Hierarchist/Egalitarian)	US$(2004)	2,560	2,650

Table 6.2: Summary of resource depletion indicators for peaking grid electricity generation using natural gas and diesel

Resource Depletion Indicator Type	Unit (per MWh)	Feedstock	
		Natural gas	Diesel
CML 1992 method	Dimensionless	7.12×10^{-11}	3.83×10^{-10}
CML 2001 method	t Sb-eq.	4.99×10^{-3}	4.58×10^{-3}
RDI 1998	t/yr	2.31×10^{-3}	6.85×10^{-3}
Eco-Indicator 99 method (Hierarchist)	MJ surplus energy	905	1,230
Eco-Indicator 99 method (Egalitarian)	MJ surplus energy	537	711
ReCiPe 2008 method (Individualist)	US$(2004)	1,700	1,660
ReCiPe 2008 method (Hierarchist/Egalitarian)	US$(2004)	3,740	3,660

Table 6.3: Summary of resource depletion indicators for residential heating using natural gas and black coal

Resource Depletion Indicator Type	Unit (per GJ_{heat})	Feedstock	
		Natural gas	Black coal
CML 1992 method	Dimensionless	8.57×10^{-12}	3.86×10^{-13}
CML 2001 method	t Sb-eq.	6.02×10^{-4}	3.39×10^{-4}
RDI 1998	yr	2.78×10^{-4}	1.84×10^{-4}
Eco-Indicator 99 method (Hierarchist)	MJ surplus energy	109	7.43
Eco-Indicator 99 method (Egalitarian)	MJ surplus energy	64.8	60.2
ReCiPe 2008 method (Individualist)	US$(2004)	204	97.6
ReCiPe 2008 method (Hierarchist/Egalitarian)	US$(2004)	451	216

The CML 1992 method (Heijungs et al. 1992) measures the impact of abiotic depletion by dividing the raw material usage (e.g. LCI data) in the production of one unit of product (e.g. 1 MWh or 1 GJ_{heat}) with the reserves of each raw material. A higher score can either mean that the reserves of the resource are low in quantity, or that the process is resource intensive. Thus, the higher the score, the more at risk the resource is because of depletion. Given that black coal has larger reserves than natural gas, the abiotic depletion score is lower for black coal in both baseload grid electricity and residential heating than for natural gas. For peaking grid electricity, since diesel has fewer reserves than natural gas, diesel has a higher abiotic depletion score than natural gas. The indicators do not assume fossil fuels can be substituted for one another. Calculations for the CML 1992 indicators are located in Appendix A.81.

The CML 2001 method (Guinée et al. 2002a) modifies the methodology in the CML 1992 method by assuming full substitutability of fossil energy resources, i.e. one fossil fuel can be replaced with another to provide the same function. The final indicators are expressed in relation to the depletion of a reference material, i.e. antimony (Sb) per unit product. All fossil fuels are initially based on a general Abiotic Depletion Potential (ADP) for fossil energy, but their respective final ADP scores are based on their heating value. Natural gas has a higher ADP score than black coal and oil because of its higher heating value. This was observed for both peaking grid electricity and residential heating, where the final abiotic depletion score of natural gas is higher than diesel and black coal respectively. However, when the alternative feedstock has a higher consumption rate on a weight basis than natural gas, the final abiotic depletion score for the alternative feedstock will potentially be greater. This is shown in baseload grid electricity. Calculations for the CML 2001 indicators are located in Appendix A.82.

The Resource Depletion Index (RDI) (Lee 1998) measures the ratio of reserves to annual production rate (Re/Pr) of raw materials. The indicators are expressed in years, which represent the remaining life of the resource. This assumes that the reserve and annual production rate remains constant until the life of the resource reaches its end. The indicators suggest that the problem of scarcity can be avoided by using the resource with the higher Re/Pr (e.g. longer life) first, which in this case is black coal. When used in conjunction with LCI data, the final abiotic depletion score indicates the damage to resources per year. This is shown in the peaking grid electricity and residential heating, where diesel has a greater depletion potential due to its lower Re/Pr than natural gas, followed by black coal. However, baseload grid electricity gives conflicting results where black coal has a greater depletion potential than natural gas. Similar to the CML 2001 method, when the alternative feedstock has a larger consumption rate on a weight basis than natural gas, the final abiotic depletion score for the alternative feedstock may be greater. Calculations for the CML 2001 indicators are located in Appendix A.83.

The Eco-Indicator 99 method (Goedkoop & Spriensma 2001) measures the surplus energy per unit product based on substitution to alternative fuels. The substitute chosen for natural gas and black coal depends on the cultural theory perspective assumed. The Hierarchist assumes shale oil to be the substitute for natural gas, and brown coal to be the substitute for black coal. For the Hierarchist perspective, diesel has a higher score than natural gas in peaking grid electricity, and natural gas has a higher score than black coal in baseload grid electricity and residential heating. This is due to the relative difficulty and higher energy requirement to switch from natural gas and oil to shale oil as compared to switching from black coal to brown coal. The Egalitarian, on the other hand, assumes a common coal-shale substitute mix for both natural gas and black coal. In this case, some coal was assumed to be converted to a liquid oil replacement, which is an energy-intensive coal conversion process. Thus, the gap between the surplus energy required for black coal systems and that for natural gas and oil is smaller. Thus, for baseload grid electricity, the greater consumption rate on a weight basis of black coal compared to natural gas gives black coal a higher score.

Although the Eco-Indicator 99 method provides indicators based on substitution, the choice of substitute does not appear to be appropriate for the specific products being produced for most cases. In particular, for the Hierarchist perspective, shale oil is a more appropriate substitute for oil instead of natural gas. Shale oil as an alternative to natural gas is unlikely in the case of Australia because it is unsuitable in many natural gas uses such as in providing fuel for residential heating, in providing a clean-burning fuel for alumina refinery calciners, and in providing feedstock for chemicals such as NH_3 and NaCN. Calculations for the Eco-Indicator 99 indicators are located in Appendix A.84.

The ReCiPe 2008 method (Goedkoop et al. 2009) measures the marginal price increase society needs to pay to continue extracting a resource. Similar to the CML method, the ReCiPe method assumes a common endpoint characterisation factor (CF_{end}) based on crude oil for all fossil fuels. The methodology then uses the cultural theory perspectives to determine the market forces that influence the marginal price increase. The individualist perspective assumes a lower $(CF_{end})_{oil}$ (\$7,280/t oil-eq.) than the hierarchist and egalitarian perspective (\$16,070/t oil-eq.). The former perspective view oil resources as abundant and will continue to extract the resource at stable prices, while the latter two will either be willing to pay more to continue extracting the resource at a higher price or switch to a more expensive alternative to avoid resource scarcity for future generations. The marginal price increase indicator CF_{end} reflects the cost of extracting the resource. According to Appendix A.85, under the hierarchist perspective, the CF_{end} for natural gas (\$8,520/t natural gas) is higher than that of diesel (\$7,940/t diesel). This is largely due to natural gas having a higher midpoint characterisation factor (1.17 t oil-eq./t) than oil (1.09 t oil-eq./t). For the Australian case, natural gas was found to have higher marginal cost increases in peaking grid electricity and residential heating because these two sectors have relatively low natural gas efficiencies. For baseload grid electricity, the greater consumption rate on a weight basis of black coal compared to natural gas gives black coal a higher score. Calculations for the ReCiPe 2008 indicators are located in Appendix A.85.

Each of the existing resource depletion indicators covers a limited aspect of the consequences of resource depletion such as loss of availability of a single resource and the surplus energy or marginal cost to further extract resources or adopt a new technology. For abiotic depletion indicators that are based on reserves, black coal will generally produce higher impact scores because of its large reserve base, followed by natural gas and crude oil. For abiotic depletion indicators that are based on heating values, natural gas will generally produce the higher score. However, the results show that the LCI data component can influence the final abiotic depletion scores. It is not always explicit what the scores represent, especially when conflicting results are given.

Furthermore, with the existing resource depletion indicators, it is difficult to perform a system-wide analysis due to each sector producing indicators with different units (e.g. per MWh or per GJ_{heat}). It was also observed that many indicators such as the CML 2001 method, Eco-Indicator 99 method and ReCiPe 2008 method assume substitutability of fossil fuel resources. Therefore, substitution plays a vital role in managing resource depletion and scarcity.

6.3. STRENGTHS AND APPLICATION

The substitution impact methodology for resource depletion acts as a supplement to estimates of reserves, which are uncertain and difficult to determine. It achieves this by assuming scarcity is imminent, causing substitution of resources with alternatives and using the resulting impacts as a resource depletion impact indicator. The substitution impact indicators are expressed as ‘per t natural gas substituted’ (independent of consumption rate) but can be expanded on the basis of consumption rate (e.g. t natural gas consumed/yr) to provide a contribution to national emissions or expenditure.

The concept of substitutability of fossil fuel resources has been employed in well-established LCIA methodologies. The Eco-Indicator 99 method uses mining surplus energy as the resource depletion impact indicator, while the ReCiPe 2008 method uses the marginal cost of extraction. However, the methodology outlined in this thesis does not allocate resource depletion to a single measure, either as a mid-point category such as resource depletion rate, or to an end-point category that measures the damage to resource availability, as existing LCIA methodologies currently practise. Instead, it provides a quantitative assessment of Resource Depletion on the basis of the environmental impact categories (e.g. global warming, acidification, photochemical oxidation, particulate release, freshwater withdrawal, associated water withdrawal, saline water discharge and solid waste generation) as well as economic impact categories (capital and operating costs). This reduces the tendency to limit resource depletion as simply ‘damage to resources’ with no explicit consequences other than the reduced availability to current and future generations.

The methodology is able to express the impacts of resource depletion impacts using indicators that are easy to understand. The environmental impacts are expressed as mid-point indicators similar to that used in the CML 2002 method, and are normalised against Australian emissions and resource consumption to enable comparison between different categories. The economic impacts are expressed as capital and operating expenditures. The spectrum of impacts resulting from substitution of a scarce resource with alternatives can be shown graphically. For example, the environmental and economic impacts from substitution of natural gas with black coal and diesel is shown in Figure 5.5 (page 232) and Figure 5.6 (page 233) respectively, while impacts from substitution with CSG is shown in Figure 5.7 (page 234), Figure 5.8 (page 235) and Figure 5.9 (page 236).

The methodology presents the impacts of resource depletion at a sector level of an economy and for the entire economy of a region or nation. The indicators account for the resource usage pattern of a particular region or country, making them a valuable tool to assess the extent of consequences caused by resource scarcity while taking account the degree of usage of the region (e.g. heavily used or little used). For example, countries such as France, Sweden and Iceland, which rely little on natural gas and more on renewables and/or nuclear energy, will have low impacts resulting from substitution of natural gas with alternatives, because of their low natural consumption.

The methodology provides environmental and economic impacts at a detailed level for the extraction and downstream processing or manufacturing stages. This enables users to narrow down their assessment to one or more areas of their choice and also enables users to introduce their own alternatives for the selected sectors. A detailed analysis can be restricted to the upstream section to examine the effects of wellhead composition on the emissions and cost of natural gas extraction and processing, or to a specific sector such as grid electricity generation to examine the emissions and costs of different alternatives.

The methodology allows for substitution with multiple alternative resources as shown with the substitution of natural gas with black coal in baseload electricity generation, the manufacturing sector and the residential sector, and substitution with diesel in peaking power generation and the mining sector. The modular nature of the methodology allows users to choose different combinations of alternatives for different sectors to achieve the best outcome, such as to minimise the impacts of resource depletion, or where alternatives are restricted in certain sectors (e.g. black coal is not a suitable alternative for natural gas in peaking power generation).

Additionally, the methodology shows the impacts that arise from using resources of the same type, but with varying concentrations and different extraction and processing methods. This was shown using the substitution of natural gas with CSG, where both resource systems produced the same downstream impacts but produce different impacts at the upstream section. In Chapter 5.5, substitution with CSG was shown to produce less emissions and lower cost penalties, but increases associated water extraction by more than 4.5 t for every t natural gas substituted. In addition, sensitivity analyses were in Chapter 0 to examine the effect of variation in difficulty to access natural gas and wellhead composition on the emissions and cost of natural gas extraction and processing. The methodology captures these differences, discouraging the notion that certain resources are completely interchangeable and can be treated the same without taking into account their differences in environmental and economic impacts.

The flexible nature of the methodology and indicators makes them useful for resource management and allocation in a resource scarcity scenario. Using this methodology, policy and decision makers are able to identify priority sectors that will be allocated resources that are limited and sectors that must replace the scarce resource with a suitable alternative before others.

Thus far, the methodology is used to demonstrate the impacts of resource depletion and scarcity. One possible application of the methodology will be to analyse scenarios outside the context of scarcity and where substitution is desired. For example, if China were to limit its coal usage due to the environmental disadvantages and substitute coal with natural gas, the resulting impacts could include a higher price of natural gas due to increased demand which will lead to increases in downstream product costs. The methodology will be able to analyse the environmental and economic benefits and risk of the substitution.

Using the methodology, a system-wide study has been performed over the Australian economy. This study has revealed several issues with substitution of natural gas with alternative resources. Firstly, remote locations of processing centres will restrict the type of alternative suitable for natural gas, e.g. choosing diesel in lieu of black coal as a substitute in the mining sector. There are also difficulties in substituting for natural gas due to the limitations in certain applications. For instance, natural gas can be used in OCGT to enable rapid response to peak electricity demand, and provides clean combustion gases for calciners in alumina refineries, but it will be difficult to use black coal for these two applications. Furthermore, the major consumers of natural gas in Australia are revealed together with their impact profiles. These major consumers will cause a greater impact on resource depletion, and will also experience greater impacts due to a natural gas scarcity.

There may be further learning in realising the full spectrum of environmental impacts and their relative importance resulting from substitution.

6.4. LIMITATIONS

The substitution impact methodology makes the assumption that scarcity is imminent, but does not forecast the exact point in time when scarcity will occur. As previously mentioned, scarcity is generally difficult to predict due to the uncertainty regarding new discoveries of a resource. One of the factors is the variation and uncertainty of reserve data, which determines the resource life and availability. This is due to the use of different measures, different interpretation of figures and political pressures to adjust or construe statistics to favour a particular standpoint.

The methodology does not take into account market forces that will likely take effect when resource depletion reaches a certain point. For example, higher prices can reduce demand for a resource causing consumption to decrease. Furthermore, no allowance is made for technological advances or price changes to drive innovation that will occur in the future. This has the effect of either improving the process to reduce emissions or costs, or to improve the conversion of the resource to a downstream product. Such changes, if implemented, will influence the magnitude and profiles of the substitution indicators. There can also be potential for new demands as the need for further processing of mineral resources in Australia increases.

The proposed methodology assumes scarcity of natural gas in Australia, but does not take into account that uneconomic reserves could become feasible due to the technological and price changes, nor does it factor in new discoveries. These factors may render the substitution indicators, which rely on the basis of resource scarcity, less relevant in the short term.

Another limitation is that the methodology is not able to anticipate the changes in technology for downstream processes in the future. The methodology employed in this thesis uses existing technologies, most of which are in the mature stage, such as combined cycle gas turbine for electricity generation and the Haber-Bosch process for ammonia production. In the future, these may be superseded by new processes. While some of these new processes in the early stages of research and development in Australia (e.g. electricity from solar thermal plants or tidal wave energy, H_2 from biomass), there is uncertainty of their adoption in the future. In some cases, the lack of LCI or cost data for these new processes hinders them from being used in the methodology.

The methodology aims to capture the impacts of resource depletion beyond a single sector and over a wider scope (e.g. whole country). Extensive data gathering is required for an accurate representation of a wider system. This may become difficult if the sectors are small or if the relevant data are absent or of limited accuracy. Sectors that are not represented will reduce the accuracy of the substitution impact indicators in representing the actual impacts of the wider system. The approach adopted has been to extrapolate from detailed data for major contributors in Australia’s natural gas network.

6.5. IMPROVEMENTS AND FUTURE WORK

The plants chosen to represent each sector were selected based on the best available technology, appropriate scale and quality of data, but do not account for every plant in the sector (e.g. a wide variety of power stations of different efficiencies and capacity sizes). The accuracy of the proposed methodology can be improved with better quality data that is more relevant to the Australia context and to the respective sectors. Another recommended work for the future will be to analyse the impacts of resource scarcity at the state level, as some of the impacts are localised. For example, the majority of residential gas consumption is centred in Victoria where the climate is colder and more people use gas for heating as compared to the other states. This will further develop the study of the impacts of natural gas in Australia by identifying which state will be most affected by a natural gas scarcity.

The methodology chose not to consider transportation and distribution costs in order to simplify the analysis. In reality, these sections highlight major differences between fossil fuels such as natural gas and black coal. For natural gas, this will include pipeline capital costs, the cost of running energy and the environmental impacts of the pipeline and natural gas transportation (e.g. fugitive emissions). For black coal, sections such as the railway transportation section contribute greatly to the environmental impacts and costs of the black coal option. These impacts are also challenging to model as the transportation network in Australia is diverse, requiring many assumptions must be made (e.g. distance between upstream and downstream processing points, terrain, climate, etc.)

Some environmental impacts are difficult to categorise because of variations across different sectors (e.g. water discharge impacts are different for each sector as some pollutants are only found or are found in greater quantities in certain sectors). This can be remedied with more impact categories that are able to capture a larger spectrum of environmental impacts. This should include categories such as eutrophication and PM2.5, reflecting the potential human health problemsfrom finer particles.

Further development of the methodology implies capability to assess social impacts. Social impact indicators need to be quantifiable to operate within the methodology. Social impacts that arise from substitution from natural gas to alternatives could include changes to employment in each sector, land use conflict between the mining and agricultural sectors and social impacts derived from increased emission levels and higher costs.

Originally designed to assess the consequences of scarcity, the methodology can be applied to examine the impacts of substituting one resource for another in other scenarios. The methodology is not restricted to fossil fuels, as it can potentially operate with a wide range of alternatives including renewables. This is provided the environmental and economic impact data over the life cycle are known. The challenge lies in overcoming the differences and limitations of the substitution alternatives, especially in producing the same quantity and quality of product. For example, the intermittent nature of renewable energy sources such as wind and solar needs to be addressed in order to qualify their use as suitable alternatives for baseload power generation.

The range of substitution alternatives available for different sectors and the difference in ease or viability of substitution in each sector can be explored further, especially for renewables such as solar and biomass. The number and viability of alternatives for substitution can potentially be used as an indicator to assess the severity of resource depletion. Resource depletion has bigger ramifications where alternative substitutes are difficult to implement, such as in chemicals manufacture (e.g. NaCN) and in ethylene production which relies on ethane supply from oil and gas sources. Furthermore, there is a need to complement this methodology with a method to choose the best combination of alternatives under different scenarios, e.g. scenario when natural gas is available but in limited quantities, or scenario when renewables is favoured over natural gas in certain sectors.

The thesis has not considered recycling of waste products, or industrial ecology practices which turns waste streams into energy and material flows for other processes, thus decreasing the impacts of water emissions and solid waste generation. Future work is required to explore these possibilities and take them into account. For instance, the salt product from CSG production can potentially be sold to markets if there is a demand. Furthermore, industrial ecology practices will also create inter-relations between different sectors, which will change the way how each sector is affected by a resource scarcity. For instance, in a natural gas scarcity, a town municipal can source waste heat from a nearby power plant for residential heating instead of natural gas.

In this thesis, the natural gas usages in different Australian economic sectors were analysed. Another future work will be to compare resource usage patterns in different countries such as the U.K. and U.S.

6.6. CONCLUSION

The substitution impact methodology has been demonstrated by examining the impacts of substitution of natural gas with black coal, diesel and CSG in the grid electricity, mining, ammonia, alumina and nickel refining and residential heating sectors of Australia during a natural gas scarcity. Using this methodology, a resource depletion impact analysis can now be performed at a broader economic or national level. The methodology has revealed that the consequences of resource depletion will result not only in a change in environmental and cost impacts, but has also revealed the issues of substitution with alternatives such as the effects of remote locations and the difficulties of substitutability in certain applications. It is able to identify the major natural gas consumers in Australia and their impact profiles, and how they are each affected by a natural gas scarcity.

Using this methodology, the impacts resulting from substitution of natural gas with black coal and diesel was revealed to be an increase in emissions to air, including an increase in approximately 2 t GHG per t natural gas substituted, $124 billion worth of new capital investment and nearly doubling in operating costs. Alternatively, substitution of natural gas with CSG showed decrease in emissions to air and capital and operating costs, but an increase in associated water extraction by 4.5 t per t natural gas substituted and an increase in salt waste generation.

The methodology is recommended as a tool to measure resource depletion and assess the impacts caused by resource scarcity at a broader level. It can be applied to a wider range of resources and substitution cases, and has room for improvement by including more mid-point category environmental impact indicators, economic indicators and social indicators. Policy and decision makers can use this methodology to assess the impacts of a resource scarcity on the economy of an entire region or nation. It can also be used to examine the environmental and economic benefits or risks of a resource substitution for different countries.

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Appendix

A.1. Normalisation factors

This section outlines the methods used to calculate the Australian emissions and material flows, which are then used to normalise the environmental impacts of substitution of natural gas.

The LCA characterisation factors used in this section are obtained from Table 4.1.

(a) Global Warming Potential (GWP)
2013 Australian CO_2 emissions = $4.08\text{x}10^8$ t CO_2-e/yr (Department of the Environment n.d.)
2013 Australian CH_4 emissions = $5.35\text{x}10^6$ t/yr
= $1.12\text{x}10^8$ t CO_2-e/yr (Department of the Environment n.d.)
2013 Australian N_2O emissions = $8.47\text{x}10^4$ t/yr
= $2.63\text{x}10^7$ t CO_2-e/yr (Department of the Environment n.d.)

2013 total CO_2 equivalent emissions = $5.46\text{x}10^8$ t/yr

(b) Acidification Potential (ADP)
2013 Australian SO_2 emissions = $1.20\text{x}10^6$ t SO_2-e/yr (NPI)
2013 Australian NO_x emissions = $7.30\text{x}10^5$ t/yr (NPI)
= $5.11\text{x}10^5$ t SO_2-e/yr
2013 Australian H_2S emissions = 540 t/yr (NPI)
= 1020 t SO_2-e/yr
2013 total SO_2 equivalent emissions = $1.71\text{x}10^6$ t SO_2-e/yr

(c) Photochemical Oxidation Potential (POP)
2013 Australian CO emissions = $6.50\text{x}10^5$ t/yr (NPI)
= $1.76\text{x}10^4$ t C_2H_4-e/yr
2013 Australian CH_4 emissions = $5.35\text{x}10^6$ t/yr (Department of the Environment n.d.)
= $3.21\text{x}10^4$ t C_2H_4-e/yr
2013 Australian VOC emissions = $9.70\text{x}10^4$ t/yr (NPI)
= $4.04\text{x}10^4$ t C_2H_4-e/yr
2013 Australian NO_x emissions = $7.3\text{x}10^5$ t/yr (NPI)
= $2.04\text{x}10^4$ t C_2H_4-e/yr
2013 total C_2H_4 equivalent emissions = $1.10\text{x}10^5$ t C_2H_4-e/yr

(d) Particulate Matter Formation (PMF)
2013 Australian PM_{10} emissions = $8.30\text{x}10^5$ t PM_{10}/yr (NPI)

(e) Freshwater Withdrawal (FWW)
This indicator is normalised using the amount of freshwater extracted from the environmental across Australia in 2013. The 2013 Water Account Australia records this as 82,297 GL. The majority of the extracted water was used for hydro-electricity generation (62,366 GL).

Water extracted from the environment in Australia (2013) = 82,297 GL (ABS 2013a)
= $8.23\text{x}10^{10}$ t/yr

(f) Associated Water Withdrawal (AWW)
This indicator is normalised using the estimated potential water co-production from onshore conventional petroleum and CSG production over 25 years.

Total potential future water production over 25 years	= 7835 GL (RPS Australia East Pty Ltd 2011)
	= 7.84×10^9 t/yr
Estimated average water production per year	= $7.84 \times 10^9 / 25$
	= 3.13×10^8 t/yr

(g) Saline Water Discharge (SWD)

This indicator is normalised with the amount of regulated discharge water across Australia in 2013. The 2013 Water Account Australia records this as 62,818 GL. This figure includes the water used for hydro-electricity generation.

Regulated discharge water in Australia (2013)	= 62,818 GL (ABS 2013a)
	= 6.28×10^{10} t/yr

(h) Solid Waste Generation (SWG)

This indicator is normalised with the amount of solid waste generation across Australia in 2011. Randell et al. (2014) records this as 61,933,000 t. This figure includes fly ash.

Solid waste generation in Australia (2011)	= 6.19×10^7 t/yr (Randell et al. 2014)

The environmental impacts in units of t natural gas substituted is normalised using Equation A.1.

$$\text{Impacts}\left(\text{yr/t natural gas substituted}\right) = \frac{\text{Impacts}\left(\text{t/t natural gas substituted}\right)}{\text{Normalisation Factor}\left(\text{t/yr}\right)} \quad (\text{Equation A.1})$$

The summary of the normalisation factors is shown in Table A.1.

Table A.1: Normalisation factors for environmental impact indicators

Damage category	Normalisation values	Units
Global Warming Potential (GWP)	5.46E+08	t CO_2-e/yr
Acidification Potential (ADP)	1.71E+06	t SO_2-e/yr
Photochemical Oxidation Potential (POP)	1.10E+05	t C_2H_4-e/yr
Particulate Matter Formation (PMF)	8.30E+05	t/yr
Freshwater Withdrawal (FWW)	8.23E+10	t/yr
Associated Water Withdrawal (AWW)	3.13E+08	t/yr
Saline Water Generation (SWD)	6.28E+10	t/yr
Solid Waste Generation (SWG)	6.19E+07	t/yr

A.2. Australian plant cost inflation index

Table A.2: Estimates of plant cost inflation indices for Australia (Brennan 2012)

Financial year June	Materials price index	Producer price index	Average weekly earnings	Plant cost index
1981	-		-	-
1982	125.4		283.75	100.0
1983	139.6		324.15	112.8
1984	147.3		349.45	120.3
1985	155.5		376.08	128.2
1986	167.9		399.48	137.3
1987	180.9		427.98	147.5
1988	196.8		454.48	158.6
1989	214.9		487.30	171.6
1990	231.9		520.95	184.3
1991	243.7		555.40	195.1
1992	245.2		580.75	200.2
1993	245.7		591.08	202.0
1994	249.2		608.78	206.5
1995	255.9		634.00	213.6
1996	261.2		662.43	220.6
1997	262.4		688.23	225.4
1998	264.7		716.65	231.0
1999	266.9	100.0	743.68	236.3
2000	269.2		768.55	241.3
2001	269.9		808.57	247.9
2002	275.0		853.57	257.1
2003	286.4		897.40	269.0
2004	289		952.83	278.7
2005	300.7	116	1008.10	292.4
2006		120	1032.00	300.9
2007		124	1091.03	314.5
2008		131	1142.28	330.8
2009		129	1201.10	336.8
2010		132.5	1256.70	349.1
2011		137.0	1315.03	363.1
2012		138.5	1353.66	370.4

Note: The Australian Bureau of Statsitcs (ABS) has ceased publishing the materials price index for buildings other than houses but published a producer price index (similar data) from the year 2000. The estimates have been updated to include data up to the year 2012.

A.3. Currency exchange rates

Table A.3 Historical exchange rates from 1993 to 2012 to convert U.S. or European costs to Australian costs (Oanda n.d.)

Financial year ending June	US Dollar (US$) to Australian Dollar (A$)	Euro (€) to Australian Dollar (A$)
1993	1.4747	
1994	1.3607	
1995	1.3763	
1996	1.2655	
1997	1.3471	
1998	1.6170	
1999	1.5192	1.5725
2000	1.6975	1.5961
2001	1.9624	1.6888
2002	1.8058	1.7925
2003	1.5090	1.7173
2004	1.3961	1.7132
2005	1.3281	1.5990
2006	1.3306	1.6902
2007	1.1548	1.5824
2008	1.0378	1.6375
2009	1.2465	1.7537
2010	1.1447	1.4595
2011	0.9283	1.3278
2012	0.9715	1.1958

A.4. Operating cost parameters from different literature

Table A.4: Operating cost parameters from different literature

Cost parameters	Brennan (1998)	Peters et al. (2003)	This study	Justification
Payroll overheads	30-50% of process labour wages	-	40% of operating labour	Middle of range from Brennan
Supervision	10-30% of process labour wages plus payroll overheads	15% of operating labour	15% of overhead labour plus payroll overheads	Value from Peters et al. falls in middle of range from Brennan
Maintenance (labour and materials)	2-12% of fixed capital investment	2-6% of fixed capital investment (simple chemical processes) 5-9% of fixed capital investment (average processes with normal operating conditions) 7-11% of fixed capital investment (complicated processes, severe corrosion operating conditions or extensive instrumentation)	2% of fixed capital	Lower end of range selected, otherwise costs become too high
Consumables	5-20% of process labour wages plus payroll overheads	-	10% of overhead labour plus payroll overheads	Middle of range from Brennan
Plant overheads	50-150% of process labour wages plus payroll overheads	50-70% of operating labour, supervision and maintenance costs	100% of overhead labour plus payroll overheads	Middle of range from Brennan
Laboratory	5-25% of process labour wages plus payroll overheads	10-20% of operating labour	10% of overhead labour plus payroll overheads	Middle of range from Brennan
Property insurance	0.1-3% of fixed capital investment	0.4-1% of fixed capital investment	1% of fixed capital	Middle of range from Brennan
Property taxes	1-4% of fixed capital investment	-	1% of fixed capital	Lower end of range chosen assuming plant is located in rural or undeveloped area
Administrative costs	2-6% of total manufacturing cost	2-5% of total product cost	4% of production costs for stand-alone plants 2% of production costs for integrated plants	Middle of range from Brennan and Peters et al., lower for integrated plants because of shared administration with main plant

Marketing/selling expenses	5-25% of total manufacturing cost	2-20% of total product cost	4% of production costs for stand-alone plants 2% of production costs for integrated plants	Lower range chosen because distribution costs not included
Research and development	0-5% of total manufacturing cost	5% of total product cost	5% of production costs for stand-alone plants 2% of production costs for integrated (utility and chemicals) 1% of production costs for integrated plants (utility only)	Value taken from Peters et al., lower for utility as less research is required

A.5. Labour and utility cost calculations

(a) Labour cost calculations

The labour cost is derived from ABS data found in '8155.0: Australian Industry', in the main from 'Table 4: Industry performance by industry subdivision' under the column 'wages and salaries per employee' in units of thousand Australian dollars per year. Where possible, the wages for the related sector are derived from the 2011-2012 edition. If not reported, the wages are taken from an earlier edition and adjusted using the Australian wage price indices published by ABS (ABS 2012b) rounded to the nearest 1000. The wage price indices are located in '6345.0: Wage price index, Australia' for the year 2012', in Table 9a under the column 'Financial year index; Ordinary time hourly rates of pay excluding bonuses; Australia; Private; Manufacturing'. The adjustment method is similar to that used for the Australian plant cost inflation index in Appendix A.2 and for the currency exchange rates in Appendix A.2 as shown in the example calculation below.

Example 1:

- Wages for one employee in chemical manufacturing sector in 2012= \$84,000/yr
- 2011 wage price index for manufacturing, private = 102.3
- 2012 wage price index for manufacturing, private = 106.2
- Wages for one employee in chemical manufacturing sector in 2012 = \$84,000/yr*106.2/102.3 = \$87,000/yr

Example 2:

- Wages for one employee in chemical manufacturing sector in 2012= \$79,000/yr
- 2011 wage price index for manufacturing, private = 102.3
- 2012 wage price index for manufacturing, private = 106.2
- Wages for one employee in chemical manufacturing sector in 2012 = \$79,000/yr*106.2/102.3 = \$82,000/yr

(b) Cooling water cost calculations

This section describes the procedure to estimate the cost of providing recirculated cooling water to process plants. The costs were based on a worked example in Brennan (1998). The costs include the cost of make-up water, electricity cost and fixed capital related costs. The costs exclude operating labour, plant overhead charges, chemical treatment or effluent treatment costs. Interest charges on capital were also excluded.

Assumptions

Flow rate of recirculated water = $0.65\ m^3/s$

Flow rate of make-up water = $0.65\ m^3/s$ x 0.0192 [A]]
= $0.0125\ m^3/s$

Fixed capital cost of cooling tower, recirculation pumps and piping = \$4.0 million for $0.65\ m^3/s$ [B]

Electricity consumption in water recirculation and cooling tower fans = 0.6 kWh/m^3 cooling water [B]]

Unit cost of make-up water = 100 cents/m^3 (Range = 50 - 150 cents/m^3 [C])

Unit cost of electricity = 3.5 cents/kWh (Range = 3.3 – 3.8 cents/kWh [D])

Capacity factor = 85% [E]

Calculations

Cost of make-up water = 0.0125/0.65 x 100 cents/m^3
= 1.92 cents/m^3 cooling water

Electricity cost = 0.6 kWh/m^3 x 3.5 cents/kWh
= 2.1 cents/m^3 cooling water

Annual operating cost at 16% capital = 0.16 x \$4 million = \$0.64 million/yr

Annual operating cost per m^3 cooling water = $0.64 \times 10^6 \times 100 / (0.65 \times 3600 \times 24 \times 365 \times 0.85)$
= 3.67 cents/m^3 cooling water

Total cost of recirculating cooling water = 1.92 + 2.10 + 3.67 = 7.7 cents/m^3 cooling water

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[B] Brennan, D. (2013). Sustainable process engineering: Concepts, strategies, evaluation, and implementation, Pan Stamford Publishing.
[C] Smart, A. and A. Aspinall (2009). Water and the electricity generation industry. Waterlines Report Series No.18. Canberra, National Water Commission
[D] Electricity costs calculated in thesis
[E] Assumption used in thesis

A.6. LCI for natural gas and coal upstream systems (adapted from May 2003)

Table A.5: Material flow data for natural gas and black coal upstream systems (May 2003)

	Production of 1 tonne of mixed petroleum products from an average natural gas mining subsystem		**Production of 1 tonne of coal from an average black coal mine**	
	Input	**Output**	**Input**	**Output**
Units	**MWh/t**	**MWh/t**	**MWh/t**	**MWh/t**
Electricity	0	0	1.97E-02	0
Units	**t/t natural gas**	**t/t natural gas**	**t/t black coal**	**t/t black coal**
Natural gas	0.476	0.396	0	0
Black coal	0	0	1	1
Diesel	4.58E-03	0	1.50E-03	0
Petrol	1.31E-06	0	0.00000114	0
Aviation fuel	3.71E-04	0	0	0
Crude oil	1.66E-04	1.65E-04	0	0
Water (low quality)	0.0392	0.0361	7.97E-01	1.21E-01
Water (high quality)	0	0	4.56E-08	0
Produced water	0	0.647	0	0
CO_2	0	0.336	0	4.71E-03
CH_4	0	3.56E-03	0	3.52E-03
N_2O	0	1.86E-05	0	1.35E-07
VOC	0	1.35E-03	0	7.29E-06
CO	0	5.94E-04	0	2.63E-05
NO_x	0	2.12E-03	0	6.79E-05
SO_2	0	1.95E-04	0	1.38E-05
H_2S	0	4.19E-11	0	0
PM_{10}	0	1.02E-04	0	2.80E-06
Solid waste	0	1.30E-04	0	0
Drilling solids	1.15E-03	0.00E+00	0	0
Drilling fluid waste	0	4.28E-03	0	0
Drill cuttings	0	2.34E-03	0	0
Produced sand	0	1.34E-04	0	0

A.7. Upstream natural gas material data from other sources

NETL (2010b) performed a life cycle analysis on a natural gas combined cycle power plant. Table A.6 summarises the emissions to air data from foreign offshore well operation from Table 2-1 (pg. 26). Units are in tonnes per tonne natural gas produced. According to the report, the foreign gas profile was based on natural gas extraction in Trinidad and Tobago and only includes offshore extraction and tanker transport. The processing of natural gas occurs on the offshore platform. It was reported that well construction will produce more sulphur oxide emissions than well operation and are attributable to the combustion of diesel and upstream electricity required for the production and delivery of construction materials.

Table A.6: U.S. foreign offshore natural gas extraction and processing material flows (NETL 2010b)

Substance	Input	Output	Note
CO_2	0	9.50E-02	
CH_4	0	4.93E-04	Assumed 0.1% of natural gas by mass
N_2O	0	2.33E-06	
VOC	0	1.54E-06	Assumed 0.01% of natural gas by mass
CO	0	5.82E-05	
NO_x	0	2.27E-04	
SO_2	0	2.50E-06	
PM_{10}	0	4.68E-06	

When compared with the Australian natural gas upstream inventory data in Table 4.10, the following observations were made:

- U.S. CO_2 emissions are less than 40% compared to that of Australia
- U.S. CH_4, N_2O, NO_x and CO emissions were 14-20% compared to that of Australia
- U.S. SO_2 emissions are less than 2% compared to that of Australia
- U.S. particulate emissions are more than 6% compared to that of Australia

The second report from NETL (2011) features the life cycle greenhouse gas inventory of natural gas extraction, delivery and electricity generation. The data is representative of domestic offshore natural gas extraction and processing, specifically from the Gulf of Mexico.

- Out of the 100% natural gas extracted from the ground, 88.1% exits as the final product. 1.3% is lost as fugitive losses, 3% is vented and flared and 7.6% is used flare and fuel use. Both the extraction and processing stages are accounted for. The losses and internal consumption figure is higher than that reported for Australia.
- The greenhouse gas data are taken from the Raw Material Acquisition (RMA) values for upstream greenhouse gas inventory results found in Table B-1 located in Appendix B (pg. B-2). The units were originally in g/MJ natural gas but this is converted into t/t natural gas using a higher heating value of 51.34 MJ/t for natural gas. These are relatively similar to that of the Australian data.
- The water removed from natural gas through glycol dehydration was reported to be 0.045 lb per thousand cubic feet natural gas (1.07×10^{-3} t/t natural gas). This is much lower than the Australian figure for produced water (less than 1%). This may be considered to be part of the produced water from natural gas extraction and processing, but only reflects a portion of it.

Most of the produced water would be separated using liquid-gas separation at the wellhead, and this was not reported.

- VOC was removed from natural gas through absorption in the acid gas removal unit. The reported figure of 6.59 lb per thousand cubic feet natural gas ($1.57\text{x}10^{-1}$ t/t natural gas) was much higher than the Australian figure. This is not emissions data and is treated instead as a co-product of acid gas removal, which is sold as a high value product on the market. The Australian figure is at least 1% of this figure, which would be reasonable for an estimate of VOC emission.
- The report assumed a H_2S concentration of 0.5% by mass of raw natural gas. H_2S was removed from natural gas through absorption in the acid gas removal unit. The reported figure of 0.21 lb per thousand cubic feet natural gas ($9.42\text{x}10^{-3}$ t/t natural gas) was also much higher than the Australian figure. Again, this is not emission data and the fate of the H_2S was not explicitly stated. It can be deduced that H_2S will be converted into SO_2, which would yield $9.42\text{x}10^{-3}$ t/t natural gas for a 100% conversion. The Australian figure is only around 1% of this figure and is too low. Assuming that Australian offshore gas fields has half the sulphur content of U.S. gas fields, a new Australian figure for SO_2 emissions of $4.78\text{x}10^{-3}$ t/t natural gas was recommended.

Table A.7: U.S. domestic offshore natural gas usage/losses and greenhouse gas emissions for extraction and processing (NETL 2011)

Substance	Input	Output		Note
Natural gas	1.14	1.00	[B]	11.9% consumed as fuel and lost through fugitive losses, venting, flaring and fuel use
CO_2	0	1.42E-01	[B]	2.76 g/MJ natural gas x 51.34 MJ/t
CH_4	0	6.88E-03	[B]	0.134 g/MJ natural gas x 51.34 MJ/t
N_2O	0	6.06E-06	[B]	$1.18\text{x}10^{-4}$ g/MJ natural gas x 51.34 MJ/t

When compared with the Australian natural gas upstream inventory data in Table 4.10, the U.S. greenhouse gas emissions were found to be half that of Australia's.

A.8. Capital cost data for offshore natural gas projects in Australia

The offshore conventional gas projects in Table A.8 were chosen because of the availability of their capacities and their costs for both the offshore well and the onshore gas processing plant components. The Reindeer gas field and Devil Creek gas processing plant project was chosen as the baseline project.

Table A.8: Offshore conventional gas projects in Australia

No	Project	Company	Location	Capacity	Cost	Cost includes	Ref
1	BassGas	Origin	VIC	• 70 TJ/day (~20 PJ/yr) gas • 65,000 tonnes/yr LPG • 1 million barrels/yr condensate	A$750 million (2006)	• Offshore platform (Yolla field) (80m water depth, 3km reservoir depth, 150km offshore) • Offshore and onshore pipeline • Onshore processing plant (Lang Lang) • Sales gas pipeline	[A][B]
2	Longtom	Nexus	VIC	~75 MMscf/day	A$230 million (2010)	• 2 horizontal subsea wells (52km) • Pipeline connected to Patricia Baleen pipeline (19km)	[C][D]
	Patricia Baleen/Orbost/Longtom processing plant	Santos	VIC	100 TJ/day (36.5 PJ/yr) gas	A$120 million	• Onshore processing plant	[C]
3	Minerva	Santos, BHP Billiton	VIC	• 150 TJ/day (54.8 PJ/yr) • 219,000 barrels/yr condensate	A$250 million (2005)	• 2 subsea wellheads (60m water depth, 10km offshore) • Offshore pipeline • Onshore processing plant (Minerva) (4.5km inland)	[C][E]
4	Otway (Thylacine)	Woodside, Origin	VIC	• 205 TJ/day (75 PJ/yr) gas • 100,000 tonnes/yr LPG • 800,000 barrels/yr condensate	A$810 million (2004)	• Offshore, unmanned platform (100m water depth, 70 km offshore) • Offshore and onshore pipeline • Onshore processing plant (Otway)	[F]
	Otway (Geographe)	Woodside, Origin	VIC		~A$290 million	• Pipeline connected to Otway main offshore pipeline	[F]
5	Reindeer gas field/Devil Creek processing plant	Apache Energy/Santos	WA	• 220 TJ/day (~80 PJ/yr) gas • 160 kL/day condensate	A$1.05 billion (2012)	• Offshore, unmanned wellhead (58m water depth, 92km offshore) • Offshore (92km) and onshore (10km) pipeline • Onshore processing plant	[G][H]

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A.9. Operating costs of U.S. offshore gas platforms

Table A.9 presents the annual operating costs for offshore gas platforms in the Gulf of Mexico. 12- and 18-well platforms at depths of 30, 91 and 183 metres were analysed. Each depth corresponded to a distance from shore. Meals, platform maintenance, helicopter and boat transportation of personnel and supplies, communication costs, insurance costs for platform and production equipment, and administrative expenses are included in normal production expenses. Natural gas transportation costs to shore and disposal costs were not factored in. The average annual operating cost for an offshore well was calculated to be $9.63 million in 2009 US dollars, or $13.2 million in 2012 Australian dollars.

Table A.9: Annual operating costs for a single Gulf of Mexico offshore platform in 2009 US dollars (EIA 2010)

Platform type	**12-Slot Platform**	**12-Slot Platform**	**18-Slot Platform**	**18-Slot Platform**	**18-Slot Platform**
Depth (feet/metres)	**100/30**	**300/91**	**100/30**	**300/91**	**600/183**
Distance from shore (miles/kilometres)	**50/80**	**100/161**	**50/80**	**100/161**	**125/201**
Labour	1,230,200	1,230,200	1,355,900	1,355,900	1,355,900
Supervision	184,500	184,500	203,400	203,400	203,400
Payroll overhead	565,900	565,900	623,700	623,700	623,700
Food expense	122,600	122,600	140,200	140,200	140,200
Labour transportation	3,461,100	3,567,500	3,461,100	3,567,500	3,604,000
Surface equipment	201,400	201,400	201,400	201,400	229,700
Operating supplies	40,300	40,300	40,300	40,300	45,900
Workover	1,804,600	1,921,300	2,706,900	2,881,900	2,953,700
Communications	57,800	59,000	77,000	77,800	78,200
Administrative	588,800	588,800	639,000	639,000	652,600
Insurance	412,400	464,800	605,000	645,400	1,037,400
Total	**8,669,600**	**8,946,300**	**10,053,900**	**10,376,500**	**10,924,700**

The maximum gas production was assumed to be 40 million cubic feet of gas per day per platform. This is equivalent to around 313,000 tonnes of natural gas produced per year per platform. Thus, the cost to extract one tonne of natural gas is estimated to be $42.10 in 2012 Australian dollars. The costs to bring the gas to shore and disposal costs were assumed to make up 10% of the final costs, bringing the operating costs of the extraction stage to $48.45 per tonne of natural gas product.

A.10. Upstream black coal upstream material data from other sources

Spath et al. (1999) performed a life cycle assessment on pulverised coal-fired power production and included inventory data for surface mining of coal. The inventory data was reported based on an average coal power plant with a 360 MW capacity and efficiency of 32%, which consumes 448,171 kg coal for every GWh electricity. As the inventory data are reported per kWh net electricity produced averaged over the life of the system, this need to be converted to per tonne coal delivered to represent the upstream section. As such, information regarding the power plant in this report is only used to extract the surface mining data and is not representative of the power plant assumptions used in this analysis.

Jig washing is a method used for cleaning coal by separating coal from the refuse with a pulsating flow of water. The lighter clean coal particulates exit at the top of the jig and the heavier refuse particles go out the bottom. Once cleaned, the coal is dewatered through the use of vibrating screens and centrifuges. Jigging is a wet process and will minimise dust particles produced during coal handling. The electricity and water required for jig washing are 0.79 MJ/t coal (2.19×10^{-4} MWh/t coal) and 0.17 t/t coal respectively. The refuse is landfilled and approximately 0.35 t dry refuse is produced for every t coal.

Methane emissions for both surface mining and underground mining are distinguished. Surface mining produces 1.91×10^{-3} t CH_4 per t coal while underground mining produces 4.23×10^{-3} t CH_4 per t coal.

The utility and chemical requirements were reported for a 4.4 million t/yr surface coal mine:

- Electricity = 14,300 MWh/(million t/yr coal mined)
- Fuel and oil = 269 m^3/(million t/yr coal mined)
- Ammonium nitrate = 2,070 t/(million t/yr coal mined)

The resource consumption and emissions to air are reported in Table 24 and Table 25 in the literature respectively. These correspond to surface mining and an average coal power plant. The inventory data for surface coal mining only can be obtained by multiplying the total with the percentage associated with surface coal mining in Table A.10.

Table A.10: Average resource consumption and emissions to air per kWh net electricity produced (Spath et al. 1999)

	Total (g/kWh)	% of total from surface coal mining
Coal (in ground)	476	0.75%
Natural gas (in ground)	1.25	38.54%
CO_2	1022	0.94%
CH_4	0.913	98.97%
N_2O	4.43×10^{-3}	22.64%
VOC	0.213	38.15%
CO	0.267	3.45%
NO_x	3.35	1.42%
SO_2	6.70	1.06%
H_2S	1.20×10^{-8}	23.24%
PM_{10}	9.21	0.14%

A sample calculation is shown below for the calculation of CO_2 emissions:

CO_2 emissions from surface coal mining= (1022/1000 t CO_2/MWh)(0.94/100)/(0.448171 t coal/MWh)
= 0.0214 t CO_2/t coal

A summary of the surface coal mining inventory data is shown in Table A.11.

Table A.11: Inventory data for surface coal mining

Inventory data (MWh/t BlC)	**Input**	**Output**
Electricity	1.45E-02	0
Inventory data (t/t BlC)	**Input**	**Output**
Black coal	1.00797	1
Natural gas	1.07E-03	0
Low quality water	1.70E-01	0
CO_2	0	2.14E-02
CH_4	0	2.02E-03
N_2O	0	2.24E-06
VOC	0	1.81E-04
CO	0	2.06E-05
NO_x	0	1.06E-04
SO_2	0	1.58E-04
H_2S	0	6.22E-12
PM_{10}	0	2.88E-05
Solid waste	0	0.35

When compared to the Australian inventory data in Table 4.13, the following were observed:

- CO_2 emissions were more than 4 times higher
- N_2O emissions were more than 15 times higher
- NMVOC emissions were 23 times higher
- SO_2 emissions were more than 10 times higher
- Particulates were 9.5 times higher
- H_2S emissions which were absent in the Australian inventory data were included

A.11. Capital cost data for open-cut black coal mines in Australia

Several black coal projects are listed in Table A.12 together with their capacities and their costs. The Range project was chosen as the baseline project to calculate the transfer price.

Table A.12: Data for opencut black coal mines in Australia

No	Project	Company	Location	Capacity (Mt)	Cost	Cost at 2012A$	Ref
1	Rocglen	Whitehaven	NSW	1.5	A$35 million (2009)	A$38 million	[A]
2	Boggabri	Idemitsu Kosan	NSW	1.5	A$35 million (2007)	A$41 million	[B]
3	Duchess Paradise	Rey Resources	WA	2.5	A$199 million (2012)	A$199 million	[C]
4	Kogan Creek/North	CS Energy	QLD	2.8	A$80 million (2007)	A$94 million	[B]
5	Wilpinjong	Excel Coal	NSW	3	A$123 million (2007)	A$145 million	[B]
6	Mount Arthur	BHP Billiton	NSW	4	US$400 million (2011)	A$379 million	[D]
7	Mt Penny	Mt Penny Coal	NSW	5	A$440 million (2011)	A$4409million	
8	The Range	Stanmore Coal	QLD	5	A$500 million (2011)	A$510 million	
9	Elimatta	New Hope Coal/Northern Energy	QLD	5	A$580 million (2010)	A$615 million	[E]
10	Mangoola/Anvil Hill	Xstrata Coal	NSW	8	US$880 million (2011)	A$833 million	[D]
11	Rolleston	Xstrata/Sumitomo/Itochu	QLD	8	A$291 million (2005)	A$369 million	[F]
12	Mount Pleasant	Rio Tinto/Mitsubishi	NSW	10.5	A$2,000 million (2012)	A$2,000 million	[C]
13	Cobbora	Macquarie Gen/Delta	NSW	12	A$1,300 million (2011)	A$1,330 million	[D]
14	Clermont	Rio Tinto/Mitsubishi	QLD	12	A$1,300 million (2010)	A$1,380 million	[E]
15	Alpha	Hancock Coal	QLD	30	A$10,000 million (2012)	A$10,000 million	[C]

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A.12. Estimation of capital and operating costs for an Australian black coal mine

The Range project owned by Stanmore Coal in Queensland and was selected to represent the average black coal mine. It is an opencut mine which produces export grade black coal.

There were two sets of costs reported by Stanmore Coal which are based on either the owner mining option or the contract mining option. Owner mining costs had higher capital costs and lower operating costs than the contract mining option. The owner mining cost was chosen for the current analysis this option will give an overall lower total operating cost, which is the sum of annualised capital costs and operating costs. Table A.13 summarises the key financial parameters for the owner mining option.

Table A.13: Key financial outputs for the owner mining option

Project economics	
Net present value (NPV)	$499 million
Internal rate of return (IRR)	18.6%
Payback period	9.0 years
Development capital (A$million)	
Coal handling and preparation plant	112
Surface infrastructure	141
Conveyor and rail loop	124
Mining fleet to first coal	150
Port capacity obligations	44
Contingency	28
Total	599
Unit costs (A$/tonne product)	
Mining and processing costs	41.9

The pre-royalty mining and processing cost is exclusive of the State Government Royalty estimated at $10.90 for the first 13 years and includes overheads. It was assumed that for the first 13 years, this mining cost included the annual capital repayment component, which is dropped for the remaining 12 years of the mine's life. To calculate this annualised capital cost, the discount rate *i* is required.

$$A = I_p\left(\frac{i(1+i)^n}{(1+i)^n+1}\right) \qquad (\text{Equation 4.7})$$

$$NPV = \sum_{t=0}^{t=k}\frac{C_t}{(1+i)^t} \qquad (\text{Equation A.2})$$

The following assumptions are made:

- IRR is 18.6% (Value of *i* when NPV = 0)
- NPV = $499 million
- A negative cash flow of A$599 million in Year 0.
- Positive cash flows C_t spread evenly over the whole 25 years of the mine's life (t = 25)
- In the first 13 years, the annualised capital cost is deducted from the positive cash flow, which is calculated using Equation 4.7.
- In the remaining 12 years of the mine's life, the positive cash flow reverts to its original value.
- For Equation 4.7, I_p is set to A$599 million and n is set to 13.

$$0=\frac{-599}{\left(1+\frac{18.6}{100}\right)^{0}}+\frac{C_t-A}{\left(1+\frac{18.6}{100}\right)^{1}}+\frac{C_t-A}{\left(1+\frac{18.6}{100}\right)^{2}}+...+\frac{C_t-A}{\left(1+\frac{18.6}{100}\right)^{13}}+\frac{C_t}{\left(1+\frac{18.6}{100}\right)^{14}}+...+\frac{C_t}{\left(1+\frac{18.6}{100}\right)^{25}}$$

$$499=\frac{-599}{\left(1+\frac{i}{100}\right)^{0}}+\frac{C_t-A}{\left(1+\frac{i}{100}\right)^{1}}+\frac{C_t-A}{\left(1+\frac{i}{100}\right)^{2}}+...+\frac{C_t-A}{\left(1+\frac{i}{100}\right)^{13}}+\frac{C_t}{\left(1+\frac{i}{100}\right)^{14}}+...+\frac{C_t}{\left(1+\frac{i}{100}\right)^{25}}$$

Using Goal Seek in Microsoft Excel 2010, the following values are obtained:

- C_t = \$128 million.
- i = 9.37%
- A = A\$81.6 million per year or A\$16.32 per tonne coal

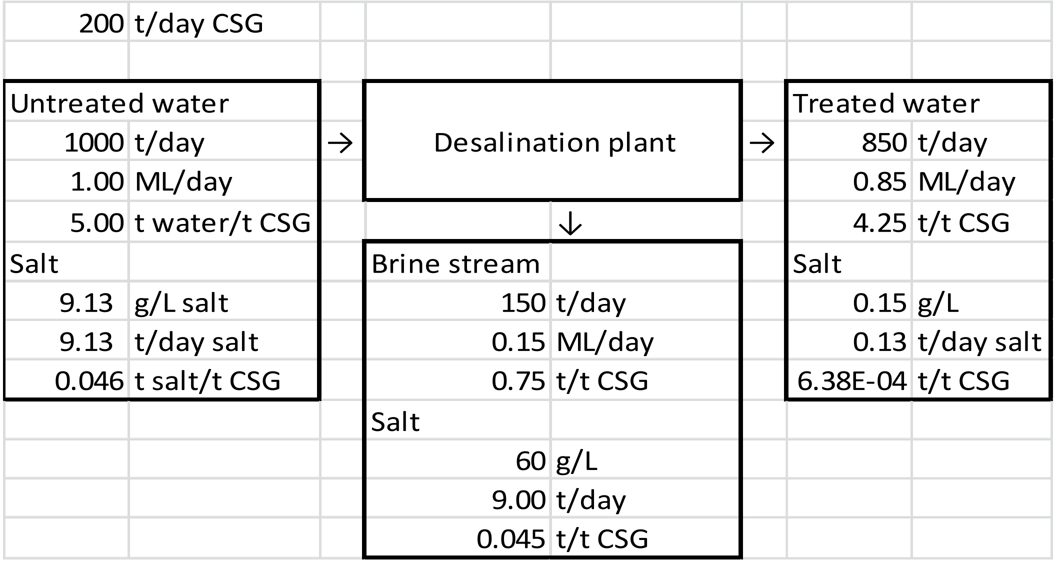
The payback period was found to be 7.8 years, which is 1.2 years lower than the 9.0 years reported by Stanmore Coal in Table A.13.

The annual capitalised capital cost of A\$16.32 per tonne coal represents the export infrastructure of the coal mine and needs to be removed. Once taken out from the mining and processing costs in Table A.13, the cost then becomes \$A25.59 per tonne coal. 6% of these costs were assumed to be processing costs for export grade coal, which need not be included for a domestic mine. Hence, the operating costs associated with mining only become \$24.05 per tonne coal.

The annualised capital cost for the domestic mine is calculated using Equation 4.7 with the mine capital cost minus the costs associated with the coal preparation and handling plant, conveyor and rail loop, and port capacity obligations, giving a capital cost of A\$319 million, as well as the parameters n = 30 and i = 10%. This was calculated to be \$6.77 per tonne coal.

A.13. Coal seam desalination plant mass balance

- Assume 200 t/day CSG production
- Associated water-to-CSG ratio of 5 (RPS Australia East Pty Ltd 2011)
- 85% of water is recovered with a concentration of 0.15 g/L (APLNG 2010a)
- 15% of brine is produced with a concentration of 60 g/L (APLNG 2010a)



200	t/day CSG						
Untreated water						Treated water	
1000	t/day	→	Desalination plant		→	850	t/day
1.00	ML/day					0.85	ML/day
5.00	t water/t CSG			↓		4.25	t/t CSG
Salt			Brine stream			Salt	
9.13	g/L salt		150	t/day		0.15	g/L
9.13	t/day salt		0.15	ML/day		0.13	t/day salt
0.046	t salt/t CSG		0.75	t/t CSG		6.38E-04	t/t CSG
			Salt				
			60	g/L			
			9.00	t/day			
			0.045	t/t CSG			

Figure A.1: Mass balance for a desalination plant

A.14. CSG greenhouse gas emissions

The CSG greenhouse gas emissions are based on data from the Australia Pacific LNG (APLNG) project.

Assumptions:

- Density of CSG (assumed to be similar to natural gas) = 0.7579 kg/m^3 (AGO 2006)
- CSG heating value (assumed to be similar to natural gas) = 37.7 MJ/m^3 (APLNG 2010c)
  = 49.74 GJ/t
- APLNG project CSG peak delivery rate = 1740 TJ/day (APLNG 2010c)
  = 12,767,700 t/yr
- Specific volume of automotive diesel fuel (38.6 MJ/L) = 1.182 kL/t (Penney et al. 2012)

Table A.14: Greenhouse gas factors and energy content of CSG and diesel usage in CSG extraction and processing activities (APLNG 2010c)

Emission source	Energy content	Emission factor (kg CO_2-eq./GJ)				Emission (kg/GJ)		
		CO_2	CH_4	N2O	Total	CO_2	CH_4	N2O
GWP_{100} (kg CO_2-eq./kg)		1	21	310		1	21	310
CSG combustion	37.7 MJ/m^3	51.1	0.2	0.03	51.33	51.1	9.52×10^{-3}	9.68×10^{-5}
Scope 1 diesel combustion (stationary)	38.6 GJ/kL	69.2	0.1	0.2	69.5	69.2	4.76×10^{-3}	6.45×10^{-4}
Scope 1 diesel combustion (transport)	38.6 GJ/kL	69.2	0.2	0.5	69.9	69.2	9.52×10^{-3}	1.61×10^{-3}
Scope 3 diesel combustion (transport and stationary)	38.6 GJ/kL	-	-	-	5.3	-		
		Emission factor (t CO_2-eq./t gas flared)				Emission factor (t/t gas flared)		
CSG flaring (drilling)		2.8	0.7	0.03	3.53	2.8	3.33×10^{-2}	9.68×10^{-5}
CSG flaring (operation)		2.7	0.1	0.03	2.83	2.7	4.76×10^{-3}	9.68×10^{-5}
		Emission factor (t CO_2-eq./t gas throughput)				Emission factor (t/t gas throughput)		
CSG leakages (for CSG production)		-	0.0012	-	0.0012	-	5.71×10^{-5}	
		Emission factor (t CO_2-eq./pipeline km)				Emission factor (t/pipeline km)		
CSG leakages (for CSG transmission)		0.02	8.7	-	8.72	0.02	4.14×10^{-1}	

The energy content figures in Table A.14 can be used to calculate the fuel usage in the CSG upstream section. The working below is to show how the amount diesel used for transportation in gas field operations is obtained.

Diesel combustion for transportation in gas field operations (kL diesel/yr) = (11,000 t CO_2-eq./yr)/(69.9/1000 t CO_2-eq./GJ)(38.6 GJ/kL)
= 4077 kL diesel/yr

Diesel combustion for transportation in gas field operations (t diesel /t CSG) = (4077 kL/yr)/(1.182 kL/t)/(12,767,700 t/yr)
= $2.70\text{x}10^{-4}$ t diesel/t CSG

The emission factors in Table A.14 are used to calculate the emission rates of CO_2, CH_4 and N_2O in the CSG upstream section. The following example is worked out to obtain the emission rate of CH_4 emissions from diesel combustion for transportation in gas field operations.

CH_4 emissions (t CH_4/yr) = (11,000 t CO_2-eq./yr)/(69.9/1000 t CO_2-eq./GJ)*($9.52\text{x}10^{-3}$/1000 t/GJ)
= 1.498 t CH_4/yr

CH_4 emissions (t CH_4/t CSG) = (1.498 t CH_4/yr)/(12,767,700 t/yr)
= $1.17\text{x}10^{-7}$ t CH_4/t CSG

Table A.15 summarises the diesel and CSG consumption and the greenhouse gas emission profile for CSG extraction and processing activities in the APLNG project.

Table A.15: Greenhouse gas emission rates for CSG extraction and processing activities (APLNG 2010c)

Source	Sum of GHG emissions (t CO_2-e/yr)	Units				CO2	CH4	N2O
Construction and drilling - gas fields								
Diesel combustion for transportation	40,000	14,825	kL diesel/yr	9.82E-04	t diesel/t CSG	39,599	5	9.23E-01
Diesel combustion for power generation	43,000	16,029	kL diesel/yr	1.06E-03	t diesel/t CSG	42,814	3	3.99E-01
Diesel combustion by other stationary equipment	72,000	26,839	kL diesel/yr	1.78E-03	t diesel/t CSG	71,689	5	6.68E-01
Operations - gas fields								
Diesel combustion for transportation	11,000	4,077	kL diesel/yr	2.70E-04	t diesel/t CSG	10,890	1	2.54E-01
Diesel combustion for power generation	11,000	4,100	kL diesel/yr	2.72E-04	t diesel/t CSG	10,953	1	1.02E-01
CSG combustion for power generation	991,000	512,107,386	m3 CSG/yr	3.04E-02	t CSG/t CSG	986,560	184	1.87
CSG combustion for other stationary equipment	1,560,000	806,142,808	m3 CSG/yr	4.79E-02	t CSG/t CSG	1,553,010	289	2.94
CSG flaring	483,000	170,671	t gas flared/yr	1.34E-02	t CSG/t CSG	460,813	813	16.52
CSG leakages	14,000	11,666,667	t throughput/yr	5.22E-05	t CH_4/t CSG	-	667	-
CSG fugitive emissions - high pressure pipeline	10,000	1147	pipeline km	3.72E-05	t CSG/t CSG	22.94	475	-
CSG venting	30,000					n/a	n/a	n/a
Operations - gas pipeline								
CSG fugitive emissions - gas pipeline	5,000	573	pipeline km	1.86E-05	t CSG/t CSG	11.47	238	
Total	3,270,000				t/yr	3,176,362	2,681	24
					Emissions (t/t CSG)	2.49E-01	2.10E-04	1.85E-06

A.15. CSG emissions to air other than greenhouse gases

The CSG greenhouse gas emissions are based on data from the Australia P acific LNG (APLNG) project.

The emissions to air covered here are NO_x, CO, SO_2, PM_{10} and VOC. There are three sources of emissions to air to calculate for the CSG upstream section:

- Emissions from the gas processing facilities
- Emissions from the water facilities
- Emissions from the wellheads

Table A.16: Exhaust emission profiles for gas engines used in a 75 TJ/day gas processing facility in the APLNG project gas fields at maximum operating load at 100% capacity (APLNG 2009)

Function	Engine model	Capacity at maximum load (bkW)	No. of engine units per facility	NO_x emission rate per engine (g/s)	Total NO_x emission rate (g/s)	CO emission rate per engine (g/s)	Total CO emission rate (g/s)	SO_2 emission rate per engine (g/s)	Total SO_2 emission rate (g/s)	PM_{10} emission rate per engine (g/s)	Total PM_{10} emission rate (g/s)
Gas compression - screw compressor	CAT G3520B	1,286	7	0.47	3.29	1.28	8.96	0.00028	0.00196	0.00012	0.00084
Gas compression - reciprocating compressor	CAT G3616	3,531	4	0.92	3.68	3.33	13.32	0.00078	0.00312	0.00031	0.00124
Power generation	CAT G3516C	1,656	1	0.67	0.67	1.33	1.33	0.00033	0.00033	0.00013	0.00013
TEG dehydration reboiler	Gas-fired boiler	n/a	1	0.01	0.01	-	0	0.00004	0.00004	0.0004	0.0004
Total emissions per gas processing facility				-	7.65	-	23.61	-	0.00545	-	0.00261

Table A.17: Exhaust emission profiles for gas engines used in water facilities corresponding with a 90 TJ/day gas processing facility (Talinga) in the APLNG project gas fields at maximum operating load at 100% capacity (APLNG 2009)

Facility	Function	Engine model	Capacity at maximum load (kW)	No. of engine units per facility	NO_x emission rate per engine (g/s)	Total NO_x emission rate (g/s)	CO emission rate per engine (g/s)	Total CO emission rate (g/s)	SO_2 emission rate per engine (g/s)	Total SO_2 emission rate (g/s)	PM_{10} emission rate per engine (g/s)	Total PM_{10} emission rate (g/s)
Water transfer station	Power generation	CAT G3406	128	1	1.72	1.72	0.11	0.11	0.00002	0.00002	0.00023	0.00023
Water treatment facility (20 ML/day)	Power generation	CAT G3406	128	4	1.72	6.88	0.11	0.44	0.00002	0.00008	0.00023	0.00092
Total emissions					-	8.6	-	0.55	-	0.0001	-	0.00115

The exhaust emission profile for a single wellhead water pump gas-fired generator are given by Balch et al. (2009). The total number of operating CSG wellheads in the Talinga gas fields that corresponds with a 90 TJ/day gas processing plant is 111 (Origin n.d.).

Table A.18: Exhaust emission profiles for wellhead water pump gas-fired generator sets (Talinga) at maximum operating load at 100% capacity (APLNG 2009)

Pollutants	NO_x	CO	SO_2
Total emissions per CSG well (g/s)	0.20	0.15	0.000014
Total emissions for 111 CSG wells (g/s)	22.2	16.65	0.001554

In the APLNG project, the quantity of gas flared per day during normal operations is approximately 3% of CSG production for each gas processing facility (APLNG 2010c). For a 75 TJ/day gas processing plant, this will correspond with an initial extraction of 75.7576 TJ/day, where 75 TJ/day is delivered and 0.7576 TJ/day is flared. The emission rate of gas flares is shown in Table A.19.

Table A.19: Exhaust emission rates of gas flares at 75 TJ/day gas processing facilities (APLNG 2009)

Pollutants	NO_x	CO	SO_2 [a]	Total hydrocarbons [b]	PM_{10} [c]
Emission rate (g/s)	1.21	36.29	6.58	2.49	-

[a] Calculated from mass balance of assumed concentration of 1ppm of H_2S in CSG fuel

[b] Assumed to be non-methane volatile organic compounds (NMVOC)

[c] No particulate emissions in a smokeless flare

The total emission rates in units of g/s are then divided by the production rate of CSG production: 75 TJ/day for the gas processing facilities and gas flares, and 90 TJ/day for the water transfer stations, water treatment facilities and the wellhead water pump gas-fired generator sets.

A.16. Data for CSG projects in Australia

Table A.20: CSG projects in Australia

No	Project	Company	Location	Capacity	Cost	Cost in A$2012	Ref
1	Argyle	Queensland Gas Company	QLD	7.4 PJ/yr	A$100 million (2007)	A$117 million	[A]
2	Tipton West CSM project	Arrow Energy/Beach Petroleum/Australian Pipeline Trust	QLD	10 PJ/yr	A$119 million (2007)	A$139 million	[A]
3	Gloucester	Metgasco	NSW	15 PJ/yr	A$200 million (2012)	A$215 million	[B]
4	Talinga	APLNG	QLD	33 PJ/yr	A$260 million (2010)	A$280 million	[B]
5	Darling Downs	APLNG	QLD	44 PJ/yr	A$500 million (2009)	A$538 million	[C]
6	Narrabri	Eastern Star Gas/Santos	NSW	150 PJ/yr	A$1,300 million (2011)	A$1,399 million	[C]

References

[A] Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) (2007). "Minerals and energy: major development projects - April 2007." from http://data.daff.gov.au/data/warehouse/pe_abarebrs99001408/ac07.4.3_mins.pdf.

[B] Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) (2009). "Minerals and energy: major development projects - April 2009." from http://data.daff.gov.au/data/warehouse/pe_abare99001641/ME09_AprListing.xls.

[C] Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) (2009). "Minerals and energy: major development projects - October 2009." from http://data.daff.gov.au/data/warehouse/pe_abare99001672/ME09_OctListing.xls

A.17. Extraction costs for U.S. coalbed methane

Firstly, the total CSG extracted is estimated. Given that the gas processing capacity is 90 TJ/day (543,882 t/yr), and 8.4% of total CSG extracted was consumed internally, the total CSG extracted was estimated to be 593,771 t/yr. This is equivalent to 75,800,000 scf/day.

A cost curve was created using lease operating costs for three different coalbed methane projects in the U.S. as outlined in Table A.21. The cost curve is shown in Figure A.2 and fits the Equation A.3.

$$I = 6160Q^{0.34} \qquad \text{(Equation A.3)}$$

where I = Capital investment in 2012 Australian dollars
Q = Capacity of CSG production in t/yr

Table A.21: Lease operating cost calculations for three U.S. coalbed methane projects

	Depth (feet)	Gas per well (thousand scf/day)	Water (billion barrels/day)	Gas per 10 wells (million scf/day)	Gas per 10 wells (t/yr)	2009US$ for 10 wells	2012A$ for 10 wells
Appalchia	2000	60	20	0.6	4,701	88,600	97,439
Black Warrior	200	100	43	1.0	7,834	133,000	146,268
San Juan	3000	500	20	5.0	39,171	194,500	189,049

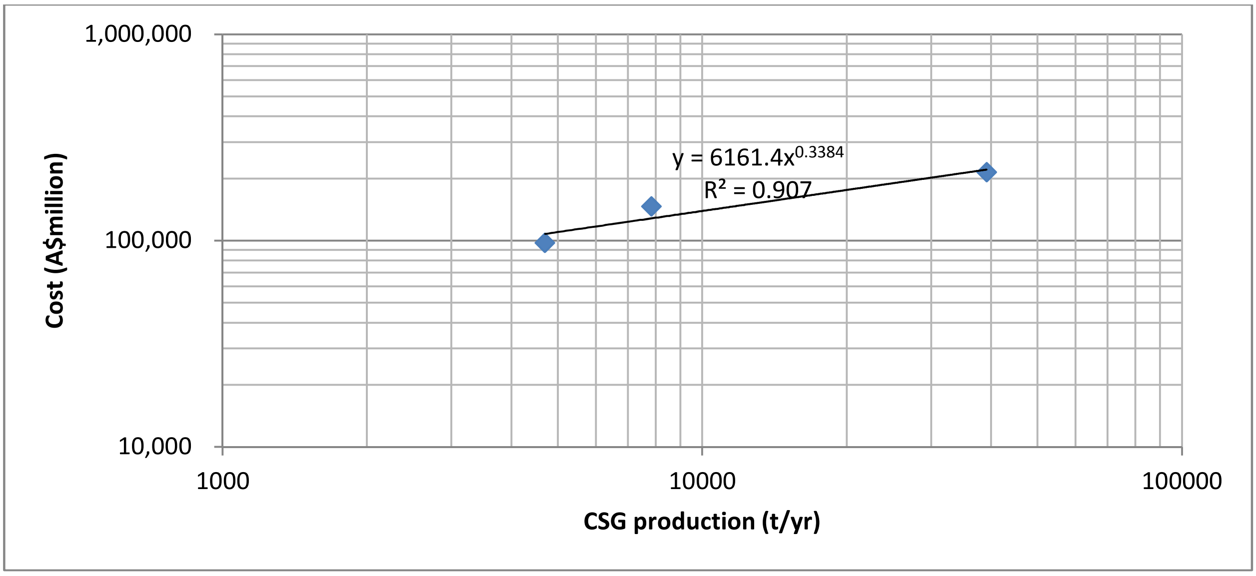


Figure A.2: Cost trend for CSG wellheads

For 593,771 tonnes CSG per year, the corresponding cost will be 2012A$565,732. This gives an operating cost for coal seam wells of $0.95 per tonne CSG extracted.

A.18. Crude oil extraction and refining LCI data

Natural gas in crude oil extraction

Natural gas usage allocated to crude oil = 0.00307 t/t crude oil produced (Sheehan et al. 1998)

Table A.22: Associated natural gas calculation from offshore crude oil extraction (Sheehan et al. 1998)

Item	Value	Comments
Gross natural gas extracted	0.26 t/t crude oil	
Natural gas reinjected	2.46%	Assume domestic case
Natural gas flared	0.067%	Assume domestic case
Natural gas vented	0.022%	Assume domestic case
Natural gas transported from offshore production facility	0.26 * (100% - 2.46% - 0.067% - 0.022%) = 0.253 t/t crude oil	

Natural gas input = 0.253 + 0.00307 = 0.256 t/t crude oil produced

Crude oil usage in crude oil extraction and refining

Crude oil is consumed in crude oil refinery for drilling and exploration. Sheehan et al. (1998) estimated that 0.215 t of crude oil is consumed for every t crude oil produced.

Sheehan et al. (1998) reported for every 7.62 t of crude oil entering the refinery, 1 t of diesel was produced together with other petroleum products. 13.4% of total emissions, raw materials and energy use required by the refinery were allocated to the production of low-sulphur diesel. Hence, it can be written that 13.4% of the 7.62 t crude oil produced entering the refinery, or 1.02 t crude oil produced, is attributed to diesel production. Although strictly speaking, this is a measure of the raw materials used to produce diesel as part of the composition of crude oil and not a measure of actual crude oil.

Table A.23 summarises the LCI data as reported by Sheehan et al. (1998). Data for extraction of crude oil is presented in two forms: Before allocation in the original units of t/t crude oil produced, and after allocation adjusted to units of t/t diesel produced. While Sheehan et al. (1998) breaks down electricity and natural gas usage in petroleum refining as sources of indirect material consumptions and emissions, this study reports electricity and natural gas in their original forms (e.g. MWh/t diesel produced and t/t diesel produced). The LCI for crude oil extraction is then added together with the LCI for diesel production from refinery to obtain the LCI for the diesel upstream section.

Table A.23: Environmental inventory data for the extraction and refining of diesel in U.S. (Sheehan et al. 1998)

	Extraction of 1 tonne crude oil (/t crude oil) (pre-allocation)		**Extraction of 1 tonne crude oil (/t diesel) (post-allocation)**		**Export of 1 tonne low sulphur diesel fuel - refinery (/t diesel)**		**Total**	
Inventory data (MWh/t)	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**
Electricity	0	0	0	0	5.84E-02	0	5.84E-02	0
Inventory data (t/t)	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**
Crude oil	1.22	1	1.05	1.02	1.02	0	1.05	0
Diesel	0	0	0	0	0	1	0	1.00
Coal	0	0	0	0	1.97E-04	0	1.97E-04	0
Natural gas	2.56E-01	2.53E-01	2.61E-01	2.58E-01	2.19E-02	0	2.51E-02	0
CO_2	0	8.99E-03	0	9.17E-03	0	2.50E-01	0	2.59E-01
CH_4	0	1.86E-05	0	1.90E-05	0	9.34E-05	0	1.12E-04
N_2O	0	2.20E-07	0	2.24E-07	0	6.15E-06	0	6.37E-06
VOC	0	1.82E-05	0	1.86E-05	0	1.06E-03	0	1.08E-03
CO	0	8.83E-06	0	9.01E-06	0	2.18E-04	0	2.27E-04
NO_x	0	9.77E-06	0	9.97E-06	0	5.25E-04	0	5.35E-04
SO_2	0	9.30E-07	0	9.49E-07	0	1.79E-03	0	1.79E-03
PM_{10}	0	1.70E-07	0	1.73E-07	0	2.62E-04	0	2.62E-04
Solid waste	0	9.80E-06	0	1.00E-05	0	6.28E-03	0	6.29E-03

Substitution of natural gas with diesel

As the study assumes a natural gas scarcity and no natural gas sources are available, the natural gas usage in the LCI was assumed to be replaced with an equivalent amount of diesel on an energy basis. As there were no heating values available for crude oil to estimate its energy content, natural gas consumed in the crude oil extraction stage was also assumed to be substituted with diesel. The additional diesel required is accounted for by increasing the extraction and refining requirements required to produce 1 net t of diesel.

Natural gas consumed in crude oil extraction = 0.00307 t/t crude oil produced

= 0.00313 t/t diesel produced

Natural gas consumed in crude oil refining = 0.0219 t/t diesel produced

Total natural gas to be substituted = 0.0251 t/t diesel produced

Higher heating value of natural gas = 51.34 GJ/t natural gas

Higher heating value of diesel = 44.95 GJ/t diesel

Equivalent diesel to substitute natural gas = 0.0287 t/t diesel produced

Table A.24: Adjustment process to substitute natural gas in diesel production from crude oil

	Production of 1 t diesel from crude oil (/t diesel)		**Material flows for equivalent diesel to substitute natural gas**		**Production of 1 t diesel from crude oil without natural gas (/0.971 t diesel)**		**Production of 1 t diesel from crude oil without natural gas (/t diesel) (adjusted)**	
Inventory data (MWh/t)	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**
Electricity	5.84E-02	0	0	0	5.84E-02	0	6.01E-02	0
Inventory data (t/t)	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**
Crude oil	1.05	0	0	0	1.05	0	1.08	0
Diesel	0	1.00	2.87E-02	0	2.86E-02	9.71E-01	2.95E-02	1.00
Coal	1.97E-04	0	0	0	0	0	0	0
Natural gas	2.51E-02	0	0	0	0	0	0	0
CO_2	0	2.59E-01	0	9.38E-02	0	3.53E-01	0	3.64E-01
CH_4	0	1.12E-04	0	1.84E-06	0	1.14E-04	0	1.17E-04
N_2O	0	6.37E-06	0	8.30E-07	0	7.20E-06	0	7.42E-06
VOC	0	1.08E-03	0	7.94E-07	0	1.08E-03	0	1.11E-03
CO	0	2.27E-04	0	1.99E-05	0	2.47E-04	0	2.54E-04
NO_x	0	5.35E-04	0	7.94E-05	0	6.15E-04	0	6.33E-04
SO_2	0	1.79E-03	0	5.63E-07	0	1.80E-03	0	1.85E-03
PM_{10}	0	2.62E-04	0	4.09E-06	0	2.66E-04	0	2.74E-04
Solid waste	0	6.29E-03	0	0.00E+00	0	6.29E-03	0	6.48E-03

A.19. Upstream substitution impact indicator calculations

For environmental impact indicators:

Step 1: Categorise material flow data into environmental impact categories

Table A.25: Environmental impact indicators for the upstream section of different fossil fuels in Australia

Feedstock	Natural gas	Black coal	Diesel	CSG
Environmental impact indicators	**t/t natural gas**	**t/t black coal**	**t/t diesel**	**t/t CSG**
Global Warming Potential (GWP)	3.16E-01	5.04E-02	4.39E-01	2.54E-01
Acidification Potential (ADP)	1.27E-03	9.08E-05	2.67E-03	6.65E-04
Photochemical Oxidation Potential (POP)	4.99E-04	1.57E-05	5.23E-04	6.49E-05
Particulate Matter Formation (PMF)	7.73E-05	5.54E-06	3.05E-04	2.11E-07
Freshwater Withdrawal (FWW)	2.88E-01	1.42E-01	4.35E-02	0.00E+00
Associated Water Withdrawal (AWW)	4.90E-01	0.00E+00	7.09E-01	5.00E+00
Saline Water Discharge (SWD)	4.51E-02	3.94E-03	4.01E-02	0.00E+00
Solid Waste Generation (SWG)	1.97E-03	7.18E+00	6.56E-03	4.50E-02

Step 2: Calculate annual environmental impacts for each upstream system

All fossil fuel values here are calculated by summing the total fossil fuel feed from all sectors covered in Chapter 4. Natural gas substitution figures correspond to the Chapter 4 sectors.

Natural gas production = 16.3 Mt/yr (represents natural gas usage in all sectors covered in Chapter 4)

Natural gas substituted with black coal = 9.38 Mt/yr

Equivalent black coal required for substitution = 23.4 Mt/yr (represents black coal usage in all sectors covered in Chapter 4)

Natural gas substituted with diesel = 6.87 Mt/yr

Equivalent diesel required for substitution = 8.60 Mt/yr (represents diesel in all sectors covered in Chapter 4)

Natural gas substituted with CSG = 16.3 Mt/yr

Equivalent CSG required for substitution = 16.3 Mt/yr (represents CSG in all sectors covered in Chapter 4)

Table A.26: Annual environmental impacts for the upstream section of different fossil fuels in Australia

Feedstock	Natural gas	Black coal	Diesel	CSG
Environmental impact indicators	**t/yr**	**t/yr**	**t/yr**	**t/yr**
Global Warming Potential (GWP)	5.14E+06	1.21E+06	3.44E+06	4.13E+06
Acidification Potential (ADP)	2.07E+04	2.18E+03	2.10E+04	1.08E+04
Photochemical Oxidation Potential (POP)	8.11E+03	3.76E+02	4.10E+03	1.05E+03
Particulate Matter Formation (PMF)	1.26E+03	1.33E+02	2.39E+03	3.43E+00
Freshwater Withdrawal (FWW)	4.69E+06	3.42E+06	3.41E+05	0.00E+00
Associated Water Withdrawal (AWW)	7.97E+06	0.00E+00	5.56E+06	8.13E+07
Saline Water Discharge (SWD)	7.33E+05	9.46E+04	3.15E+05	0.00E+00
Solid Waste Generation (SWG)	3.21E+04	1.72E+08	5.14E+04	7.32E+05

Step 3: Calculate annual substitution impacts

Table A.27: Annual environmental impacts for substitution of natural gas with different fuels in the upstream section

Feedstock	Black coal	Diesel	CSG
Environmental impact indicators	**t/yr**	**t/yr**	**t/yr**
Global Warming Potential (GWP)	- 1.76E+06	+ 1.27E+06	- 1.01E+06
Acidification Potential (ADP)	- 9.77E+03	+ 1.22E+04	- 9.88E+03
Photochemical Oxidation Potential (POP)	- 4.31E+03	+ 6.77E+02	- 7.06E+03
Particulate Matter Formation (PMF)	- 5.93E+02	+ 1.86E+03	- 1.25E+03
Freshwater Withdrawal (FWW)	+ 7.10E+05	- 1.64E+06	- 4.69E+06
Associated Water Withdrawal (AWW)	- 4.61E+06	+ 2.19E+06	+ 7.33E+07
Saline Water Discharge (SWD)	- 3.29E+05	+ 5.13E+03	- 7.33E+05
Solid Waste Generation (SWG)	+ 1.72E+08	+ 3.79E+04	+ 7.00E+05

Step 4: Divide by natural gas substituted

Natural gas substituted with black coal = 9.38 Mt/yr

Natural gas substituted with diesel = 6.87 Mt/yr

Natural gas substituted with CSG = 16.3 Mt/yr

Table A.28: Environmental substitution impacts for the upstream sections in Australia

Feedstock	Black coal	Diesel	CSG
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**
Global Warming Potential (GWP)	- 1.08E-01	+ 7.81E-02	- 6.23E-02
Acidification Potential (ADP)	- 6.01E-04	+ 7.52E-04	- 6.08E-04
Photochemical Oxidation Potential (POP)	- 2.65E-04	+ 4.16E-05	- 4.34E-04
Particulate Matter Formation (PMF)	- 3.65E-05	+ 1.14E-04	- 7.71E-05
Freshwater Withdrawal (FWW)	+ 4.36E-02	- 1.01E-01	- 2.88E-01
Associated Water Withdrawal (AWW)	- 2.83E-01	+ 1.35E-01	+ 4.51E+00
Saline Water Discharge (SWD)	- 2.02E-02	+ 3.15E-04	- 4.51E-02
Solid Waste Generation (SWG)	+ 1.06E+01	+ 2.33E-03	+ 4.30E-02

Step 5: Normalisation of environmental impacts

Table A.29: Normalised environmental substitution impacts for the upstream section in Australia

Feedstock	Black coal	Diesel	CSG
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	- 1.98E-10	+ 1.43E-10	- 1.14E-10
Acidification Potential (ADP)	- 3.51E-10	+ 4.39E-10	- 3.55E-10
Photochemical Oxidation Potential (POP)	- 2.40E-09	+ 3.77E-10	- 3.93E-09
Particulate Matter Formation (PMF)	- 4.40E-11	+ 1.38E-10	- 9.29E-11
Freshwater Withdrawal (FWW)	+ 5.30E-13	- 1.23E-12	- 3.50E-12
Associated Water Withdrawal (AWW)	- 9.04E-10	+ 4.31E-10	+ 1.44E-08
Saline Water Discharge (SWD)	- 3.22E-13	+ 5.02E-15	- 7.17E-13
Solid Waste Generation (SWG)	+ 1.71E-07	+ 3.76E-11	+ 6.95E-10

For economic impact indicators:

Natural gas substitution figures correspond to system-wide usage after extrapolation.

Natural gas usage in system-wide analysis = 27.4 Mt/yr (see Table A.125 in Appendix A.69)

Natural gas substituted with black coal = 18.5 Mt/yr (see Table A.129 in Appendix A.71)

Natural gas substituted with diesel = 8.77 Mt/yr (see Table A.133 in Appendix A.73)

Natural gas substituted with CSG = 27.4 Mt/yr (see Table A.139 in Appendix A.77)

Table A.30: Economic impacts for the upstream section of different fuels in Australia

Economic impact indicators				
Feedstock	Natural gas	Black coal	Diesel	CSG
Annualised captial costs (2012A$/t NG substituted)	85.7	17.3	n/a	83.4
Cash operating costs (2012A$/t NG substituted)	73.3	61.5	n/a	39.6
Total operating costs (2012A$/t NG substituted)	159.0	78.8	n/a	123.0

Table A.31: Economic substitution impacts for the upstream sections in Australia

Economic impact indicators			
Feedstock	Black coal	Diesel	CSG
Annualised captial costs (2012A$/t NG substituted)	+ 17.3	n/a	+ 83.4
Cash operating costs (2012A$/t NG substituted)	- 11.8	n/a	- 33.7
Total operating costs (2012A$/t NG substituted)	+ 5.5	n/a	+ 49.7

A.20. Australian reference grid electricity fuel mix

- The NSW electricity fuel mix was assumed to be 70% black coal, 12% natural gas and 18% renewables.
- The overall material data was assumed to consist only of material data from black coal and natural gas which have been reported in this analysis; the contribution from renewables was excluded from this analysis.
- Material flows for electricity generated from black coal using PCST technology are obtained from Table 4.36.
- Material flows for electricity generated from natural gas using CCGT technology are obtained from Table 4.29.

Table A.32: Material flow data for NSW electricity fuel mix

Fuel type	Black coal	Natural gas	Renewables	Total
Fuel mix	70%	12%	18%	100%
Units	t/MWh	t/MWh	t/MWh	t/MWh
Black coal	2.54E-01	0	0	2.54E-01
Natural gas	0	1.63E-02	0	1.63E-02
Cooling water	1.33E+00	9.68E-02	0	1.43E+00
Boiler feedwater	7.00E-02	9.68E-03	0	7.97E-02
Evaporation	1.19E+00	8.17E-02	0	1.27E+00
Cooling water blowdown	1.40E-01	1.51E-02	0	1.55E-01
Steam blowdown	7.00E-02	9.68E-03	0	7.97E-02
CO_2	5.48E-01	4.30E-02	0	5.91E-01
CH_4	8.87E-06	3.99E-06	0	1.29E-05
N_2O	4.01E-06	8.17E-08	0	4.09E-06
VOC	4.65E-09	5.12E-07	0	5.17E-07
CO	6.37E-05	2.45E-05	0	8.82E-05
NO_x	1.25E-03	6.07E-05	0	1.31E-03
SO_2	3.30E-09	3.97E-07	0	4.00E-07
H_2S	0	0	0	0
PM_{10}	8.93E-05	2.35E-06	0	9.16E-05
Ash	5.39E-02	0.00E+00	0	5.39E-02

A.21. Gas-fired electricity fuel consumption

BREE (2013e) provided 2010-2011 Australian generation capacities for gas based (e.g. natural gas, CSG) power generation using steam turbine, open cycle gas turbine and combined cycle gas turbine technologies. Combined cycle gas turbine power stations had the largest share of natural gas fuel consumption (63%) while open cycle gas turbine power station had the second largest share (21%) followed by steam turbine power stations (16%). The natural gas fuel consumption in Table A.33 was lower than the figure reported in BREE (2013a), so the natural gas usage for each technology in Table A.33 was scaled up such that the total fuel consumption was equal to that from BREE.

Table A.33: Performance data for gas based electricity generation technologies in Australia

Technology/Fuel	Australian generation capacity [a]		Capacity utilisation (%)	Annual generation		Efficiency (%)	Natural gas fuel consumption	
	MW	%		TWh	%		PJ	%
Steam turbine – natural gas	2,190	16%	25 [b]	4.80	12%	35.2	49.1	16%
Open cycle gas turbine – natural gas	6,870	51%	10 [c]	6.02	15%	35.2	61.6	20%
Open cycle gas turbine – CSG	519	4%	10 [c]	0.455	1%	35.2	4.65	1%
Closed cycle gas turbine – natural gas	2,610	19%	85 [c]	19.4	47%	51.6	135	41%
Closed cycle gas turbine – CSG	1,400	10%	85 [c]	10.4	25%	51.6	72.6	22%
Total	13,600	100%		41.1	100%		323	100%

[a] Generation capacities adapted from BREE (2013e)

[b] Based on Newport steam turbine power station capacity factor (Green Energy Markets 2010)

[c] Capacity utilisations for CCGT and OCGT adapted from AEGTC (Bedilion et al. 2009)

A.22. LCI data for gas- and coal-based electricity systems based on May (2003)

Table A.34: Material flow data for the generation of 1 net MWh of electricity from different fossil fuels and technologies in Australia (May 2003)

	Natural gas - OCGT		Natural gas - CCGT		Black coal - ST		Black coal - IGCC	
Inventory data (t/MWh)	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**
Natural gas	2.74E-01	0	1.40E-01	0	0	0	7.34E-03	0
Black coal	0	0	0	0	4.49E-01	0	2.52E-01	0
Fuel oil	3.21E-04	0	1.64E-04	0	3.02E-04	0		
Diesel	3.01E-07	0	1.12E-07	0	9.95E-06	0	1.06E-05	0
Petrol	3.82E-06	0	1.42E-06	0	1.09E-05	0	1.16E-05	0
LPG	3.42E-06	0	1.28E-06	0	0	0		
Low quality water	0	0	23.7	0	1.78	0	6.24E-01	0
High quality water	2.56E-04	0	1.14E-01	0	1.97E-01	0	4.60E-01	0
Evaporation	0	0	0	4.87E-01	0	1.51	0	4.71E-01
Wastewater	0	2.56E-04	0	23.3	0	3.39E-01	0	5.13E-01
Saline water								1.01E-01
CO_2	0	7.20E-01	0	3.80E-01	0	9.83E-01	0	6.34E-01
CH_4	0	9.54E-05	0	1.59E-05	0	9.85E-06	0	3.02E-05
N_2O	0	1.41E-06	0	6.97E-06	0	8.64E-06	0	9.15E-06
VOC	0	2.21E-05	0	8.90E-06	0	1.84E-05	0	7.21E-07
CO	0	5.33E-04	0	2.39E-05	0	1.19E-04	0	1.49E-04
NO_x	0	2.30E-03	0	4.97E-04	0	3.20E-03	0	1.56E-04
SO_2	0	2.98E-06	0	3.47E-06	0	4.01E-03	0	5.07E-05
PM_{10}	0	2.52E-04	0	2.29E-05	0	4.77E-04	0	7.18E-06
Ash	0	0	0	0	0	8.41E-02	0	2.58E-02

A.23. Emission to air factors

a) Emission to air factors for natural gas combustion

Table A.35: Greenhouse gas emission factors for combustion of natural gas distributed in a pipeline (DCCEE 2011)

Substance	Emission factor (kg CO_2-eq./GJ)	GWP (kg CO_2-eq./kg)	Emission factor (kg/GJ)
CO_2	51.2	1	51.2
CH_4	0.1	21	$4.76\text{x}10^{-3}$
N_2O	0.03	310	$9.68\text{x}10^{-5}$

Table A.36: Emissions to air factors for combustion of natural gas in a stationary gas turbine (DSEWPC 2012)

Substance	Emission factor (kg/PJ-HHV)	Additional information
VOC	$9.1\text{x}10^{2}$	-
CO	$3.5\text{x}10^{4}$	for uncontrolled option
	$1.3\text{x}10^{4}$	for water-steam injection option
	$6.5\text{x}10^{3}$	for lean premix option
NO_x	$1.4\text{x}10^{5}$	for uncontrolled option
	$5.6\text{x}10^{4}$	f or water-steam injection option
	$4.3\text{x}10^{4}$	for lean premix option
SO_2	$4.1\text{x}10^{5}$ x S	S = percentage sulphur content of fuel in %
	$4.51\text{x}10^{2}$	S = 0.0011 for 8.4 mg/m^3 sulphur in natural gas (see Table 4.8)
PM_{10}	$2.8\text{x}10^{3}$	for uncontrolled option

b) Emission to air factors for fuel oil combustion

Table A.37: Greenhouse gas emission factors for combustion of fuel oil (DCCEE 2011)

Substance	Emission factor (kg CO_2-eq./GJ)	GWP (kg CO_2-eq./kg)	Emission factor (kg/GJ)
CO_2	72.9	1	72.9
CH_4	0.03	21	$1.43\text{x}10^{-3}$
N_2O	0.2	310	$6.45\text{x}10^{-4}$

Table A.38: Emissions to air factors for combustion of distillate in a stationary gas turbine (DSEWPC 2012)

Substance	Emission factor (kg/PJ-HHV)	Additional information
VOC	$1.8\text{x}10^{2}$	-
CO	$1.4\text{x}10^{3}$	for uncontrolled option
	$3.3\text{x}10^{4}$	for water-steam injection option
NO_x	$3.8\text{x}10^{5}$	for uncontrolled option
	$1.0\text{x}10^{5}$	f or water-steam injection option
SO_2	$4.4\text{x}10^{5}$ x S	S = percentage sulphur content of fuel in %
	$4.4\text{x}10^{3}$	S = 0.05 for 0.05% sulphur in distillate
PM_{10}	$5.2\text{x}10^{3}$	for uncontrolled option

c) Emission to air factors for diesel combustion

Table A.39: Greenhouse gas emission factors for combustion of diesel (DCCEE 2011)

Substance	Emission factor (t CO_2-eq./GJ)	GWP (t CO_2-eq./t)	Emission factor (t/GJ)
CO_2	$6.92\text{x}10^{-2}$	1	$6.92\text{x}10^{-2}$
CH_4	$1\text{x}10^{-4}$	21	$4.76\text{x}10^{-3}$
N_2O	$2\text{x}10^{-4}$	310	$6.45\text{x}10^{-4}$

Table A.40: Emission factors for miscellaneous diesel industrial vehicle exhaust emissions (DSEWPC 2008)

Substance	Emission factor (t/kL diesel)
VOC	$4.2\text{x}10^{-3}$
CO	$1.86\text{x}10^{-2}$
NO_x	$4.5\text{x}10^{-2}$
SO_2	$2.4\text{x}10^{-5}$
PM_{10}	$3.6\text{x}10^{-3}$

d) Emission to air factors for petrol combustion

Table A.41: Greenhouse gas emission factors for combustion of petrol (DCCEE 2011)

Substance	Emission factor (t CO_2-eq./GJ)	GWP (t CO_2-eq./t)	Emission factor (t/GJ)
CO_2	$6.67\text{x}10^{-2}$	1	$6.67\text{x}10^{-2}$
CH_4	$2\text{x}10^{-4}$	21	$9.52\text{x}10^{-3}$
N_2O	$2\text{x}10^{-4}$	310	$6.45\text{x}10^{-4}$

Table A.42: Emission factors for miscellaneous petrol industrial vehicle exhaust emissions (DSEWPC 2008)

Substance	Emission factor (t/kL petrol)
VOC	$1.57\text{x}10^{-2}$
CO	$4.86\text{x}10^{-1}$
NO_x	$1.17\text{x}10^{-2}$
SO_2	$3.6\text{x}10^{-4}$
PM_{10}	$7.38\text{x}10^{-4}$

e) Emission to air factors for LPG combustion

Table A.43: Greenhouse gas emission factors for combustion of LPG (DCCEE 2011)

Substance	Emission factor (t CO_2-eq./GJ)	GWP (t CO_2-eq./t)	Emission factor (t/GJ)
CO_2	$5.96\text{x}10^{-2}$	1	$5.96\text{x}10^{-2}$
CH_4	$1\text{x}10^{-4}$	21	$4.76\text{x}10^{-3}$
N_2O	$2\text{x}10^{-4}$	310	$6.45\text{x}10^{-4}$

Table A.44: Emission factors for miscellaneous LPG industrial vehicle exhaust emissions (DSEWPC 2008)

Substance	Emission factor (t/t LPG)
VOC	0.033
CO	0.3
NO_x	0.015
SO_2	0
PM_{10}	0

f) Emission to air factors for black coal combustion

Table A.45: Greenhouse gas emission factors for combustion of black coal (DCCEE 2011)

Substance	Emission factor (kg CO_2-eq./GJ)	GWP (kg CO_2-eq./kg)	Emission factor (kg/GJ)
CO_2	8.82×10^{-2}	1	8.82×10^{-2}
CH_4	3×10^{-5}	21	1.43×10^{-3}
N_2O	2×10^{-4}	310	6.45×10^{-4}

Table A.46: Emissions to air factors for combustion of black coal in a steam cycle (DSEWPC 2012)

Substance	Emission factor (t/t BlC)	Additional information
VOC	3.0×10^{-5}	Dry bottom boilers, wall and tangentially fired
	2.0×10^{-5}	Wet bottom boilers
	6.0×10^{-4}	Cyclone furnace
CO	2.5×10^{-4}	Dry bottom boilers
NO_x	1.1×10^{-2}	Uncontrolled, dry bottom, wall fired
	5.5×10^{-3}	Low NO_x burner, dry bottom, wall fired
	6×10^{-3}	Dry bottom, wall fired, post 1978
	4.9×10^{-3}	Uncontrolled, dry bottom, tangentially fired
	1.55×10^{-2}	Uncontrolled, wet bottom, wall fired
	7×10^{-3}	Wet bottom, wall fired, post 1978
	1.65×10^{-2}	Cyclone furnace
	2.5×10^{-3}	Fluidised bed, circulating
	7.6×10^{-3}	Fluidised bed, bubbling
SO_2	$1.9 \times 10^{-2} \times S$	S = percentage sulphur content of coal as fired in %
	8.1×10^{-3}	S = 0.43 for 0.43% sulphur in coal (AGO 2006)
PM_{10}	(A)(1000)(F)(1-ER/100)(FP)	A = Weight fraction of ash in coal, default is 0.2 F = Flyash fraction of total ash, default is 0.9 ER = Emission reduction efficiency (%) FP = PM_{10} fraction of emitted particles on a mass basis
	3.4×10^{-4}	Fabric filter, ER = 99.8%, FP = 0.92
	9.6×10^{-4}	ESP plant, ER = 99.2%, FP = 0.67
	3.5×10^{-4}	A = 0.212, F = 0.9 (AGO 2006)

g) Emission to air factors for distillate/diesel combustion in boilers

Table A.47: Emissions to air factors for combustion of distillate (diesel) oil in boilers (≤30MW) (DSEWPC 2011)

Substance	Emission factor (t/t)
VOC	2.72×10^{-5}
CO	6.80×10^{-4}
NO_x	2.72×10^{-3}
SO_2	1.93×10^{-5}
PM_{10}	1.40×10^{-4}

h) Emission to air factors for natural gas combustion in boilers

Table A.48: Emissions to air factors for combustion of natural gas in boilers (>30 MW wall-fired) (DSEWPC 2011)

Substance	Emission factor (t/t)	Additional information
VOC	1.19×10^{-4}	-
CO	1.82×10^{-3}	-
NO_x	5.95×10^{-3}	for uncontrolled option
	3.03×10^{-3}	for low NO_x burner option
	2.16×10^{-3}	for flue gas recirculation + low NO_x burner option
	4.11×10^{-3}	for over fired air + low excess air option
SO_2	2.84×10^{-6} x S	S = percentage sulphur content of fuel in mg/m^3
	2.39×10^{-5}	S = 8.4 mg/m^3 sulphur in natural gas (see Table 4.8)
PM_{10}	1.6×10^{-4}	All particulates are assumed to be PM_1 with diameter around 1 micrometer

i) Emission to air factors for IGCC

Table A.49: Emissions to air factors for IGCC based on coal feedstock (NETL 2012)

Substance	Emission factor (t/t BIC)
CO_2	2.03
CH_4	7.91×10^{-6}
N_2O	9.11×10^{-9}
VOC	5.60×10^{-8}
CO	1.04×10^{-6}
NO_x	6.13×10^{-4}
SO_2	1.41×10^{-4}
PM_{10}	7.99×10^{-5}

j) Emission to air factors for diesel combustion in engines

Table A.50: Emissions to air factors for combustion of stationary large (greater than 450 kW) diesel engines (DSEWPC 2008)

Substance	Emission factor (t/MWh)	Additional information
SO_2	3.84×10^{-4}	
CO	3.34×10^{-3}	
NO_x	7.90×10^{-3}	Controlled
SO_2	4.92×10^{-3} x S^2	S is the fuel sulphur content (wt%) in diesel
	1.23×10^{-5}	S = 0.05 for 0.05% sulphur in diesel
PM_{10}	4.26×10^{-4}	

Table A.51: Emissions to air factors for combustion of natural gas in boilers (≤30 MW wall-fired) (DSEWPC 2011)

Substance	**Emission factor (t/t)**	**Additional information**
VOC	$1.19\text{x}10^{-4}$	-
CO	$1.82\text{x}10^{-3}$	-
NO_x	$2.16\text{x}10^{-3}$	for uncontrolled option
	$1.08\text{x}10^{-3}$	for low NO_x burner option
	$6.19\text{x}10^{-4}$	for flue gas recirculation + low NO_x burner option
SO_2	$2.84\text{x}10^{-6}$ x S	S = percentage sulphur content of fuel in mg/m^3
	$2.39\text{x}10^{-5}$	S = 8.4 mg/m^3 sulphur in natural gas (see Table 4.8)
PM_{10}	$1.6\text{x}10^{-1}$	All particulates are assumed to be PM_1 with diameter around 1 micrometer

Table A.52: Emissions to air factors for combustion of distillate in boilers (≤30 MW) (DSEWPC 2011)

Substance	**Emission factor (t/t)**
VOC	$2.72\text{x}10^{-5}$
CO	$6.8\text{x}10^{-4}$
NO_x	$2.72\text{x}10^{-3}$
SO_2	$1.93\text{x}10^{-5}$
PM_{10}	$1.4\text{x}10^{-4}$

A.24. Sample calculations to obtain emissions to air using emissions factors

An OCGT efficiency of 33.31% was adapted from Bedilion et al. (Bedilion et al. 2009). To reflect the switch from dry cooling to wet cooling, the efficiency was increased by 2% to 35.31%. The emissions of OCGT is calculated based on this new efficiency.

The material inputs for OCGT are adapted from Table 4.28. Each mass flow in units of t fuel/t MWh is multiplied with their respective emission factors in units of t/t fuel from Appendix A.23.

Table A.53: Emission to air factors for an OCGT power station

Substance	**Units**	**Natural gas**	**Fuel oil**	**Diesel**	**Petrol**	**LPG**
Mass flow	t fuel/MWh	2.74x10^{-1}	3.21x10^{-4}	3.01x10^{-7}	3.82x10^{-6}	3.42x10^{-6}
CO_2	t/t fuel	2.63	3.21	3.16	3.09	2.96
CH_4	t/t fuel	2.44x10^{-4}	6.30x10^{-5}	2.17x10^{-4}	4.42x10^{-4}	2.36x10^{-4}
N_2O	t/t fuel	4.97x10^{-6}	2.84x10^{-5}	2.94x10^{-5}	2.99x10^{-5}	3.20x10^{-5}
VOC	t/t fuel	3.08x10^{-5}	7.93x10^{-6}	4.20x10^{-3}	1.57x10^{-2}	3.30x10^{-2}
CO	t/t fuel	1.49x10^{-3}	6.17x10^{-5}	1.86x10^{-2}	4.86x10^{-1}	3.00x10^{-1}
NO_x	t/t fuel	3.70x10^{-3}	1.67x10^{-2}	4.05x10^{-2}	1.17x10^{-2}	1.50x10^{-2}
SO_2	t/t fuel	2.32x10^{-5}	9.69x10^{-4}	2.40x10^{-5}	3.60x10^{-4}	0
PM_{10}	t/t fuel	1.44x10^{-4}	2.29x10^{-4}	3.6x10^{-3}	7.38x10^{-4}	0

Table A.54: Calculation of emissions to air for an OCGT power station

Substance	**Units**	**Natural gas**	**Fuel oil**	**Diesel**	**Petrol**	**LPG**	**Total**
CO_2	t/MWh	5.22x10^{-1}	7.47x10^{-4}	9.50x10^{-7}	1.18x10^{-5}	1.01x10^{-5}	5.23x10^{-1}
CH_4	t/MWh	4.86x10^{-5}	1.46x10^{-8}	6.54x10^{-11}	1.69x10^{-9}	8.08x10^{-10}	4.86x10^{-5}
N_2O	t/MWh	9.87x10^{-7}	6.61x10^{-9}	8.86x10^{-12}	1.14x10^{-10}	1.09x10^{-10}	9.94x10^{-7}
VOC	t/MWh	6.12x10^{-6}	1.85x10^{-9}	1.26x10^{-9}	5.98x10^{-8}	1.13x10^{-7}	6.29x10^{-6}
CO	t/MWh	2.96x10^{-4}	1.44x10^{-8}	5.60x10^{-9}	1.86x10^{-6}	1.03x10^{-6}	2.99x10^{-4}
NO_x	t/MWh	7.34x10^{-4}	3.90x10^{-6}	1.35x10^{-8}	4.47x10^{-8}	5.13x10^{-8}	7.38x10^{-4}
SO_2	t/MWh	4.60x10^{-6}	2.26x10^{-7}	7.22x10^{-12}	1.38x10^{-9}	0	4.83x10^{-6}
PM_{10}	t/MWh	2.85x10^{-5}	5.33x10^{-8}	1.08x10^{-9}	2.82x10^{-9}	0	2.86x10^{-5}

A.25. Recirculated cooling water systems for electricity generation systems

(a) CCGT

To maintain consistency among all plants in the current analysis, the assumption was made that all plants in the current analysis use closed cycle (recirculated) water cooling. Data for closed cycle water cooling in the electricity generation industry can be found in Smart and Aspinall (2009):

- 0.68 ML/GWh for cooling
- 0.2 ML/GWh for blowdown, makeup and potable water

It is assumed that 0.68 ML/GWh will be lost due to evaporation in wet cooling towers at full load. Water is also lost from the cooling tower through blowdown, which is an essential to control the concentration level of contaminates and pollutants in the water. The amount of blowdown depends on the environmental conditions of the area and quality of the water being used. Based on a typical six cycles of concentration 0.12 ML/GWh is required. This is replaced with low quality water, which is essentially the same grade as that used as cooling water. The remaining 0.08 ML/GWh is made up of high quality water. Thus, blowdown is assumed to be one fifth of the water lost due to evaporation.

The low quality water, high quality water, evaporation, wastewater and saline water values are adjusted according to the heat rate or the amount of fuel used, which is determined by the efficiency chosen for CCGT power stations.

(b) PCST

Data for recirculated cooling for sub-critical and super-critical power stations were provided by Smart and Aspinall (2009).

- 1.7 ML/GWh for cooling water make-up in super-critical power stations (1.9 ML/GWh for sub-critical)
- 0.2 ML/GWh for blowdown (one fifth of cooling make-up, most likely rounded up)
- 0.1 ML/GWh for other uses

(c) IGCC

Data for recirculated cooling for IGCC power stations were provided by Smart and Aspinall (2009). 1.2 ML/GWh was reported, including cooling, blowdown and process water. It was assumed that water for other uses is the same as the steam turbine case, while the ratio between cooling water and blowdown make-up is the same as the steam turbine case. The approximate breakdown was assumed to be:

- 0.98 ML/GWh for cooling
- 0.116 ML/GWh for blowdown
- 0.1 ML/GWh for other uses

Table A.55: Mass balance for combined cycle power station with recirculated cooling (Smart and Aspinall 2009)

	Production of 1 MWh of electricity from a CCGT power station with recirculated cooling		Production of 1 MWh of electricity from a sub-critical PCST power station with recirculated cooling		Production of 1 MWh of electricity from a super-critical PCST power station with recirculated cooling		Production of 1 MWh of electricity from a IGCC power station with recirculated cooling	
Inventory data (t/MWh)	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**	**Input**	**Output**
Natural gas	1.36E-01	0	4.10E-01	0	3.50E-01	0	3.48E-01	0
Cooling water makeup	8.00E-01	0	2.10	0	1.90	0	1.10	0
Steam makeup	8.00E-02	0	1.00E-01	0	1.00E-01	0	1.00E-01	0
Evaporation	0	6.80E-01	0	1.90		1.70	0	0.98
Cooling water blowdown	0	1.20E-01	0	2.00E-01		2.00E-01	0	1.16E-01
Steam blowdown	0	8.00E-02	0	1.00E-01		1.00E-01	0	1.00E-01
CO_2	0	3.55E-01	0	8.84E-01		7.58E-01	0	7.50E-01

According to SPX Cooling Technologies (2009), evaporation losses (E) can be approximated as 1.6% of the total recirculating cooling water flow rate (F) for every 11°C (20°F) of temperature range, while drift (D) can be approximated as 0.02% of the total recirculating cooling water flow rate (F). Blowdown can be estimated using Equation A.4.

$$B = \frac{E - [(C-1) \times D]}{(C-1)} \qquad \text{(Equation A.4)}$$

where C is the cycles of concentration which is a ratio of the concentration of the recirculating water flow rate with respect to the concentration of the makeup water. Smart (2009) quotes the typical cycles of concentration to be six (i.e. C = 6). Using the values of E, D and C above, B was calculated to be 0.3% of the total recirculating water cooling water flow rate. The total recirculating cooling water flow rate can also be calculated:

$$M = 0.016F + 0.0002F + 0.003F = 0.0192F \qquad \text{(Equation A.5)}$$

Thus, the makeup water (M) can be estimated to be around 1.92% of the total recirculating water flow rate (F).

A.26. CCGT capital cost data

Table A.56: Capital cost of CCGT projects in Australia

No	Project	Company	Location	Capacity (MW)	Cost (2012A$million)	Ref
1	Richmond Valley	Metgasco	NSW	30	40	[A]
2	Owen Springs	Power & Water	NT	32	89.5	[A]
3	Cape Lambert	CTEC	WA	120	180	[A][B]
4	Centauri 1	Eneabba Gas	WA	168	150	[A]
5	Yarnima	BHP Billiton	WA	190	597	[A]
6	Diamantina (2 stages)	APA/AGL	QLD	242	500	[A]
7	Westlink Power Project	Westlink	QLD	300	300	[A]
8	Hanging Rock (stage 1)	Loran	NSW	300	360	[A]
9	Bamarang (2 stages)	Lumo Gen	NSW	400	400	[A]
10	Tallawarra (stage B)	EnergyAustralia	NSW	400	500	[A]
11	SEQ1	AGL	QLD	500	350	[A]
12	Mortlake Lake (stage 1)	Origin	VIC	550	810	[A]
13	Bannaby	Snowy Hydro	NSW	600	500	[A]
14	Wellington	ERM Power	NSW	660	680	[A]
15	Marulan	EnergyAustralia	NSW	700	450	[A]
16	Tarrone	AGL	VIC	900	700	[A]
17	Dalton	AGL	NSW	1000	700	[A]
18	Cherokee	Tungkillo Powerco	SA	1000	750	[A]
19	Yallourn	EnergyAustralia	VIC	1000	1300	[A]
20	Aldoga	EnergyAustralia	QLD	1500	1800	[A]
21	Blackstone	EnergyAustralia	QLD	1500	1800	[A]

References

[A] Bureau of Resource Energy and Economics (BREE) (2012). Major electricity generation projects - November 2012. http://www.bree.gov.au/files/files/publications/megp/elec-generation-projects-appendix.xls.

[B] Australian Mining (2014). "Clough wins collapsed Forge Rio Tinto contract." http://www.miningaustralia.com.au/news/clough-wins-collapsed-forge-rio-tinto-contract.

A.27. U.S. feedstock coal analysis

Table A.57: Coal analysis of Pittsburgh No.8 coal (Buchanan et al. 2003)

Rank	**Bituminous**		
Seam	**Pittsburgh No.8**		
Proximate analysis (wt%)			
	As received	**Dry**	
Moisture	6.0	0	
Ash	9.9	10.6	
Volatile matter	35.9	38.2	
Fixed carbon	48.2	51.2	
Total	100.00	100.00	
Ultimate analysis (wt%)			
	As received	**Dry**	**Air dry**
Ash	9.9	10.6	10.3
Carbon	69.4	73.8	71.9
Hydrogen	5.2	4.8	5.0
Nitrogen	1.2	1.3	1.3
Sulphur	2.9	3.1	3.0
Oxygen	11.4	6.5	8.6
Total	100	100	100
Heating value			
Higher heating value	29.0	30.8	
Higher heating value free of moisture and ash		34.5	
Lower heating value	27.7		

Table A.58: Coal analysis of Illinois No.6 coal (NETL 2010a)

Rank	**Bituminous**	
Seam	**Illinois No.6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate analysis (wt%)		
	As received	**Dry**
Moisture	11.12	0
Ash	9.7	10.91
Volatile matter	34.99	39.37
Fixed carbon	44.19	49.72
Total	100.00	100.00
Sulphur	2.51	2.82
Ultimate analysis (wt%)		
	As received	**Dry**
Moisture	11.12	71.72
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulphur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
Total	100.00	100.00
Heating value		
Higher heating value	27.11	30.51
Lower heating value	26.15	29.54

A.28. Integrated Gasification and Combined Cycle (IGCC) mass balance

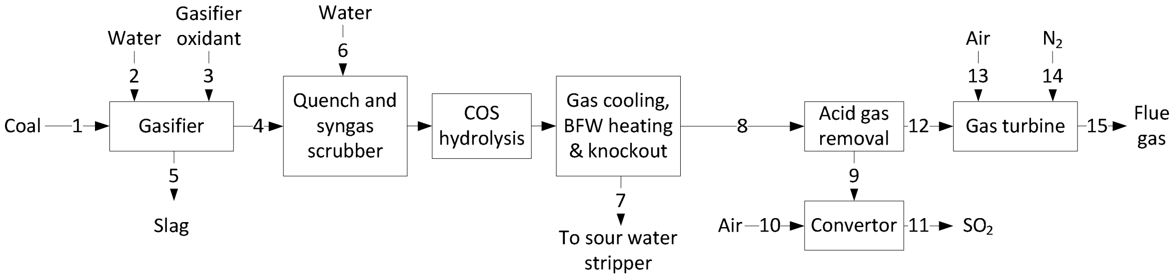


Figure A.3: Flow diagram of IGCC system

U.S. NETL IGCC

Table A.59: IGCC mass balance using Illinois No. 6 coal (NETL 2010a)

Molar flow (kmol/hr)	-	4830	5300	22200	-	5930	20000	9000	953	1250	2210	19800	106000	19600	145000
Mass flow (t/hr)	212	87	170	446	23.2	107	423	162	37	36.2	73.0	397	3050	544	4000
Components (mol%)															
Ar	-	0	0.03	0.01	-	0	0.01	0	0	0.01	0.01	0	0.01	0	0.01
CH4	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
C2H6	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
C3H8	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
i-C4H10	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
n-C4H10	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
i-C5H12	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
n-C5H12	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
n-C6H14	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
CO	-	0	0	0.36	-	0	0.40	0	0	0	0	0.41	0	0	0
CO2	-	0	0	0.14	-	0	0.18	0	0.61	0	0.26	0.16	0	0	0.08
COS	-	0	0	0.00	-	0	0	0	0	0	0	0	0	0	0
H2	-	0	0	0.34	-	0	0.38	0	0	0	0	0.39	0	0	0
H2O	-	1.00	0	0.14	-	1.00	0	1.00	0.01	0	0.01	0	0.01	0	0.06
H2S	-	0	0	0.01	-	0	0.01	0	0.18	0	0	0	0	0	0
HCl	-	0	0	0		0	0	0	0	0	0	0	0	0	0
He	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
N2	-	0	0.02	0.01	-	0	0.02	0	0.19	0.77	0.52	0.03	0.77	0.99	0.74
NH3	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
O2	-	0	0.95	0	-	0	0	0	0	0	0.12	0	0.21	0.01	0.10
SO2	-	0	0	0	0	0	0	0	0	0	0.08	0	0	0	0
Total	-	1.00	1.00	1.00	-	1.00	1.00	1.00	1.00	1.00	1.00	0.99	1.00	1.00	1.00

From NETL (2010a)

Mass of Illinois No.6 coal = 212 t/hr
Higher Heating Value (HHV) of coal = 27.1 GJ/t
Net plant efficiency = 39%
Gas turbine power = 464 MW
Steam turbine power = 276 MW
Other = 7.5 MW
Total power generated = 748 MW
Total auxiliaries = 126 MW
Net power = 622 MW

Auxiliaries include steam turbine auxiliaries 0.1 MW, Claus plant auxiliaries 0.25 MW and Claus plant recycle compressor 2.09 MW.

Efficiency changed from 39% to 45%

Net electricity generated = (212)(27.1)(0.45)/3600 = 718 MW

For this design, the auxiliaries remain the same as the 39% efficiency case, but the Claus plant and its associated auxiliaries are excluded.

Auxiliairies = (125750-250-2090)/1000 = 123 MW

Gross electricity generated = 718+123 = 842 MW
Electricity generated from gas turbine = (842)(464)/747 = 523 MW

Australian IGCC

Table A.60: IGCC mass balance using Australian black coal (see Chapter 0 for black coal composition)

Stream number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Vapour fraction	-	0	1.00	1.00	-	0	1.00	0	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Molar flow (kmol/hr)	-	5540	4850	20700	-	5920	18000	9440	773	217	990	17200	92800	17200	114000
Mass flow (t/hr)	212	99.7	156	431	41.5	107	399	170	30.7	6260	37	368	2680	476	3520
Components (mol%)															
Ar	-	0	0.03	0.01	-	0	0.01	0	0	0.01	0	0	0.01	0	0.01
CH4	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
C2H6	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
C3H8	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
i-C4H10	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
n-C4H10	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
i-C5H12	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
n-C5H12	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
n-C6H14	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
CO	-	0	0	0.37	-	0	0.43	0	0	0	0	0.45	0	0	0
CO2	-	0	0	0.14	-	0	0.19	0	0.73	0	0.57	0.17	0	0	0.09
COS	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
H2	-	0	0	0.30	-	0	0.35	0	0	0	0	0.36	0	0	0
H2O	-	1.00	0	0.17	-	1.00	0	1.00	0.02	0.01	0.02	0	0.01	0	0.01
H2S	-	0	0	0	-	0	0	0	0.04	0	0	0	0	0	0
HCl	-	0	0	0		0	0	0	0	0	0	0	0	0	0
He	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
N2	-	0	0.02	0.01	-	0	0.02	0	0.22	0.77	0.34	0.01	0.77	0.99	0.78
NH3	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0
O2	-	0	0.95	0	-	0	0	0	0	0.21	0.05	0	0.21	0.01	0.11
SO2	-	0	0	0	-	0	0	0	0	0	0.03	0	0	0	0
Total	-	1.00	1.00	1.00	-	1.00	1.00	1.00	1.01	1.00	1.00	1.00	1.00	1.00	1.00

Mass of Australian black coal = 212 t/hr
Higher Heating Value (HHV) of coal = 24.4 GJ/t
Net plant efficiency = 45%
Net electricity generated = (212)(24.4)(0.45)/3600 = 646 MW

For this design, the auxiliaries remain the same as the U.S. NETL case, where the Claus plant and its associated auxiliaries are excluded.

Auxiliairies = (125750-250-2090)/1000 = 123 MW

Gross electricity generated = 646+123 = 769 MW
Electricity generated from gas turbine = 769(464)/747 = 478 MW

A.29. Grid electricity substitution impact indicator calculations

Step 1: Categorise material flow data into environmental impact categories

Table A.61: Environmental impacts for baseload electricity generation from different fossil fuels

Option	Baseload grid electricity			Peaking grid electricity		
Feedstock	Natural gas	Black coal	CSG	Natural gas	Diesel	CSG
Technology	CCGT	PCST	CCGT	OCGT	IC	OCGT
Environmental impact indicators	**t/MWh**	**t/MWh**	**t/MWh**	**t/MWh**	**t/MWh**	**t/MWh**
Global Warming Potential (GWP)	3.59E-01	7.84E-01	3.59E-01	5.24E-01	6.75E-01	5.24E-01
Acidification Potential (ADP)	3.57E-04	1.25E-03	3.57E-04	5.22E-04	5.54E-03	5.22E-04
Photochemical Oxidation Potential (POP)	2.16E-05	5.24E-05	2.16E-05	3.16E-05	4.71E-04	3.16E-05
Particulate Matter Formation (PMF)	1.96E-05	1.28E-04	1.96E-05	2.86E-05	4.26E-04	2.86E-05
Freshwater Withdrawal (FWW)	8.87E-01	2.00	8.87E-01	0.00E+00	0.00E+00	0.00E+00
Saline Water Discharge (SWD)	2.07E-01	3.00E-01	2.07E-01	0.00E+00	0.00E+00	0.00E+00
Solid Waste Generation (SWG)	0.00E+00	7.70E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Economic impact indicators	**2012A$ /MWh**	**2012A$ /MWh**	**2012A$ /MWh**	**2012A$ /MWh**	**2012A$ /MWh**	**2012A$ /MWh**
Annualised captial costs	17.2	43.2	7.2	91.8	33.8	91.8
Cash operating costs	39.5	42.0	33.3	109.7	273.6	100.7
Total operating costs	**56.6**	**85.2**	**40.5**	**201.6**	**307.4**	**192.5**

Step 2: Calculate the environmental impacts resulting from substitution of natural gas

Table A.62: Environmental impacts due to substitution of natural gas in baseload electricity generation in Australia

Option	Baseload grid electricity		Peaking grid electricity	
Feedstock	NG→BlC	NG→CSG	NG→D	NG→CSG
Technology	CCGT→PCST	CCGT	OCGT→IC	OCGT
Environmental impact indicators	**t/MWh**	**t/MWh**	**t/MWh**	**t/MWh**
Global Warming Potential (GWP)	4.25E-01	0.00E+00	1.51E-01	0.00E+00
Acidification Potential (ADP)	8.89E-04	0.00E+00	5.02E-03	0.00E+00
Photochemical Oxidation Potential (POP)	3.07E-05	0.00E+00	4.40E-04	0.00E+00
Particulate Matter Formation (PMF)	1.08E-04	0.00E+00	3.97E-04	0.00E+00
Freshwater Withdrawal (FWW)	1.11E+00	0.00E+00	0.00E+00	0.00E+00
Saline Water Discharge (SWD)	9.33E-02	0.00E+00	0.00E+00	0.00E+00
Solid Waste Generation (SWG)	7.70E-02	0.00E+00	0.00E+00	0.00E+00
Economic impact indicators	**2012A$/MWh**	**2012A$/MWh**	**2012A$/MWh**	**2012A$/MWh**
Annualised captial costs	43.2	0.0	33.8	0.0
Cash operating costs	2.5	-6.2	163.8	-9.0
Total operating costs	**45.7**	**-6.2**	**197.6**	**-9.0**

Step 3: Calculate annual environmental impacts

Natural gas usage in baseload grid electricity generation = 5.49 x 10^6 tonnes (Figure 5.1)

Australian 2012 baseload grid electricity generation = 40.4 x 10^6 MWh

Natural gas usage in peaking grid electricity generation = 1.75 x 10^6 tonnes (Figure 5.1)

Australian 2012 peaking grid electricity generation = 8.83 x 10^6 MWh

Table A.63: Annual environmental impacts due to substitution of natural gas in baseload electricity generation in Australia

Feedstock	NG→BIC	NG→CSG	NG→D	NG→CSG
Technology	CCGT→PCST	CCGT	OCGT→IC	OCGT
Environmental impact indicators	**t/yr**	**t/yr**	**t/yr**	**t/yr**
Global Warming Potential (GWP)	1.72E+07	0.00E+00	1.33E+06	0.00E+00
Acidification Potential (ADP)	3.59E+04	0.00E+00	4.44E+04	0.00E+00
Photochemical Oxidation Potential (POP)	1.24E+03	0.00E+00	3.88E+03	0.00E+00
Particulate Matter Formation (PMF)	4.36E+03	0.00E+00	3.51E+03	0.00E+00
Freshwater Withdrawal (FWW)	4.49E+07	0.00E+00	0.00E+00	0.00E+00
Saline Water Discharge (SWD)	3.77E+06	0.00E+00	0.00E+00	0.00E+00
Solid Waste Generation (SWG)	3.11E+06	0.00E+00	0.00E+00	0.00E+00
Economic impact indicators	**2012A$mil/yr**	**2012A$mil/yr**	**2012A$mil/yr**	**2012A$mil/yr**
Annualised captial costs	1,743.3	0.0	299.0	0.0
Cash operating costs	102.8	-249.8	1,447.8	-79.8
Total operating costs	**1,846.1**	**-249.8**	**1,746.8**	**-79.8**

Step 4: Divide by natural gas substituted

Natural gas substituted in baseload grid electricity generation = 5.49 x 10^6 tonnes

Natural gas substituted in peaking grid electricity generation = 1.75 x 10^6 tonnes

Table A.64: Substitution impact indicators for baseload electricity generation in Australia

Option	Baseload grid electricity				Peaking grid electricity			
Feedstock	NG→BIC		NG→CSG		NG→D		NG→CSG	
Technology	Extraction and refining	CCGT→PCST	Extraction and refining	CCGT	Extraction and refining	OCGT→IC	Extraction and refining	OCGT
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**
Global Warming Potential (GWP)	-1.08E-01	3.02E+00	-6.23E-02	0.00E+00	7.81E-02	7.60E-01	-6.23E-02	0.00E+00
Acidification Potential (ADP)	-6.01E-04	5.93E-03	-6.08E-04	0.00E+00	7.52E-04	2.53E-02	-6.08E-04	0.00E+00
Photochemical Oxidation Potential (POP)	-2.65E-04	-3.93E-05	-4.34E-04	0.00E+00	4.16E-05	2.21E-03	-4.34E-04	0.00E+00
Particulate Matter Formation (PMF)	-3.65E-05	7.57E-04	-7.71E-05	0.00E+00	1.14E-04	2.00E-03	-7.71E-05	0.00E+00
Freshwater Withdrawal (FWW)	4.36E-02	8.22E+00	-2.88E-01	0.00E+00	-1.01E-01	0.00E+00	-2.88E-01	0.00E+00
Associated Water Withdrawal (AWW)	-2.83E-01	-2.83E-01	4.51E+00	0.00E+00	1.35E-01	0.00E+00	4.51E+00	0.00E+00
Saline Water Discharge (SWD)	-2.02E-02	6.66E-01	-4.51E-02	0.00E+00	3.15E-04	0.00E+00	-4.51E-02	0.00E+00
Solid Waste Generation (SWG)	1.06E+01	1.12E+01	4.30E-02	0.00E+00	2.33E-03	0.00E+00	4.30E-02	0.00E+00
Economic impact indicators	**2012A$/t NG substituted**		**2012A$/t NG substituted**		**2012A$/t NG substituted**		**2012A$/t NG substituted**	
Annualised captial costs	18.7		-		170.4		-	
Cash operating costs	317.4		-45.5		825		-45.5	
Total operating costs	**336.1**		**-45.5**		**995.4**		**-45.5**	

Step 5: Normalisation of environmental impacts

Table A.65: Normalised substitution impact indicators for baseload electricity generation in Australia

Option	Baseload grid electricity		Peaking grid electricity	
Feedstock	NG→BlC	NG→CSG	NG→D	NG→CSG
Technology	CCGT→PCST	CCGT	OCGT→IC	OCGT
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	5.52E-09	-1.14E-10	1.53E-09	-1.14E-10
Acidification Potential (ADP)	3.46E-09	-3.55E-10	1.52E-08	-3.55E-10
Photochemical Oxidation Potential (POP)	-3.56E-10	-3.93E-09	2.04E-08	-3.93E-09
Particulate Matter Formation (PMF)	9.12E-10	-9.29E-11	2.55E-09	-9.29E-11
Freshwater Withdrawal (FWW)	9.99E-11	-3.50E-12	-1.23E-12	-3.50E-12
Associated Water Withdrawal (AWW)	-9.04E-10	1.44E-08	4.31E-10	1.44E-08
Saline Water Discharge (SWD)	1.06E-11	-7.17E-13	5.02E-15	-7.17E-13
Solid Waste Generation (SWG)	1.80E-07	6.95E-10	3.76E-11	6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised captial costs	18.7	-	170.4	-
Cash operating costs	317.4	-45.5	825.0	-45.5
Total operating costs	**336.1**	**-45.5**	**995.4**	**-45.5**

A.30. Off-grid power stations in Western Australia

Table A.66: Gas-fired power stations connected to the NWIS in the Pilbara region (2012)

Location	Plant name	Purpose	Company	Fuel	Technology	Total capacity (MW)	Reference
Cape Lambert		Iron ore mining	Rio Tinto	Natural gas	Steam turbine	105	[A][B]
Dampier		Iron ore mining	Rio Tinto	Natural gas	Steam turbine	120	[A][B]
Karratha	Karratha power station	Residential/commercial	ATCO Australia	Natural gas	Gas turbine	86	[A][B][C]
Karratha	Yurralyi Maya (7 Mile)	Iron ore mining	Rio Tinto	Natural gas	Gas turbine	160-250	[A][B]
Newman		Iron ore mining	Alinta Energy/BHP Billiton	Natural gas	Gas turbine	140-184	[A][B]
Paraburdoo		Iron ore mining	Rio Tinto	Natural gas	Gas turbine	120+20 (standby)	[A][B]
Port Hedland	Boodarie power station Port Hedland power station	Iron ore mining	Alinta Energy/BHP Billiton	Natural gas	Gas turbine	160-210	[A][B]

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[A] Bureau of Resources and Energy Economics (BREE) (2013). Beyond the NEM and the SWIS: 2011-12 regional and remote electricity in Australia. http://www.bree.gov.au/publications/rare/index.html.

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Table A.67: Gas-fired power stations generating off-grid electricity in Western Australia (non-NWIS) (2012)

Location	Plant name	Power used for	Company	Technology	Total capacity (MW)	Reference
Barrow Island		Gas processing	Chevron (Gorgon LNG)		10	[A]
Broome (WKPP)		Residential/Commercial	Energy Developments/Horizon Power	Reciprocating engine	40-49	[A][C]
Burrup Peninsula	Karratha gas plant	Gas processing	Woodside (North West Shelf Joint Venture)		240	[A][B]
Burrup Peninsula	Pluto phase 1	Gas processing	Woodside		160	[A][B]
Cape Preston magnetite mine		Magnetite mining	CITIC Pacific Mining		450	[A][F]
Carnarvon	Mungullah	Residential/Commercial	Horizon Power		15.3	[A][G]
Darlot gold mine		Gold mining	Energy Developments/Barrick Gold of Australia	Reciprocating engine	11.6-12	[A][C]
Derby (WKPP)		Residential/Commercial	Energy Developments/Horizon Power	Reciprocating engine	12-13.1	[A][C]
Devil Creek gas plant		Gas processing	Apache Energy		10	[A]
Enfield project			Woodside Petroleum		10	[A]
Esperance		Residential/Commercial	Burns & Roe Worley		38.5	[A][H]
Exmouth		Residential/Commercial	Worley Parsons		8	[A][I]
Fitzroy Crossing (WKPP)		Residential/Commercial	Energy Developments/Horizon Power	Reciprocating engine	3.7-4	[A][C]
Gwalia Deeps gold mine		Gold mining	Pacific Energy KPS		17	[A]
Halls Creek (WKPP)		Residential/Commercial	Energy Developments/Horizon Power	Reciprocating engine	3.3-4	[A][C]
Jundee gold mine		Gold mining	Energy Developments/Newmont	Reciprocating engine	22.5	[A][C]
Laminara project			Woodside		15	[A]
Leinster nickel mine		Nickel mining	Southern Cross Energy		65	[A]
Mount Magnet		Gold mining	Energy Developments/Mount Magnet South		1.9-3.6	[A][E]
Mount Magnet mine		Gold mining	Energy Developments/Ramelius Resources	Reciprocating engine	18-22	[A][C][D]
Mt Keith nickel oeprations		Nickel mining	Southern Cross Energy		116	[A]
Murrin Murrin nickel mine		Nickel mining	Glencore Investments	Combined cycle	80	[A]
Nifty copper mine		Copper mining	Aditya Birla		22.8	[A]
Onslow (private)			Onslow Electric Power		3.6	[A][B]
Plutonic gold mine		Gold mining	Barrick Gold of Australia		28.3	[A]
Stybarrow oil and gas			BHP Billiton		30	[A]
Sunrise Dam gold mine		Gold mining	Energy Developments/AngloGold Ashanti	Reciprocating engine	26.8-28	[A][C]
Telfer gold mine		Gold mining	Newcrest Mining		159-161	[A][B]
Tropicana mine			KPS (Pacific Energy)		47	[A]
Varanus Island gas plant		Gas processing	Apache Energy		8	[A]
Vincent project			Woodside		15	[A]
Wandoo			Vermillion Oil and Gas		2.5	[A]
Wheatstone			Chevron		1	[A]
Wiluna gold mine		Gold mining	Apex Gold		20.6	[A]

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[A] Bureau of Resources and Energy Economics (BREE) (2013). Beyond the NEM and the SWIS: 2011-12 regional and remote electricity in Australia. http://www.bree.gov.au/publications/rare/index.html.

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A.31. Calculation of boiler plant cost

Purchased cost of package boiler plants are provided by Peters et al. (2003). The steam capacity of the boiler plant is required to calculate the purchased costs. Equation A.6 is used to calculate the steam rate for a boiler.

$$\text{Boilercapacity(MW)} = \frac{\dot{m}_{steam}\left(h_{steam} - h_{water}\right)}{1000} \qquad \text{(Equation A.6)}$$

Where $\dot{m}_{steam}$ = Mass flow rate of steam, in kg/s

h_{steam} = Enthalpy of steam leaving boiler, kJ/kg

h_{water} = Enthalpy of water entering boiler, kJ/kg

To calculate the boiler capacity, the enthalpies of steam and water at a given pressure are required. Choosing an average pressure of 30 bar, the enthalpies of water and steam at 30 bar is given to be 1008.4 kJ/kg and 2802.3 kJ/kg. Cost curves are provided corresponding to steam pressures of 4240 kPa, 2860 kPa and 1825 kPa. The choice of a pressure of 30 bar also helps to facilitate the calculation of steam flows based on the closest pressure which is 2860 kPa.

The fuel consumption can be calculated by multiplying the boiler capacity by $\frac{100}{85}$, given the assumption that the boiler is 85% efficient.

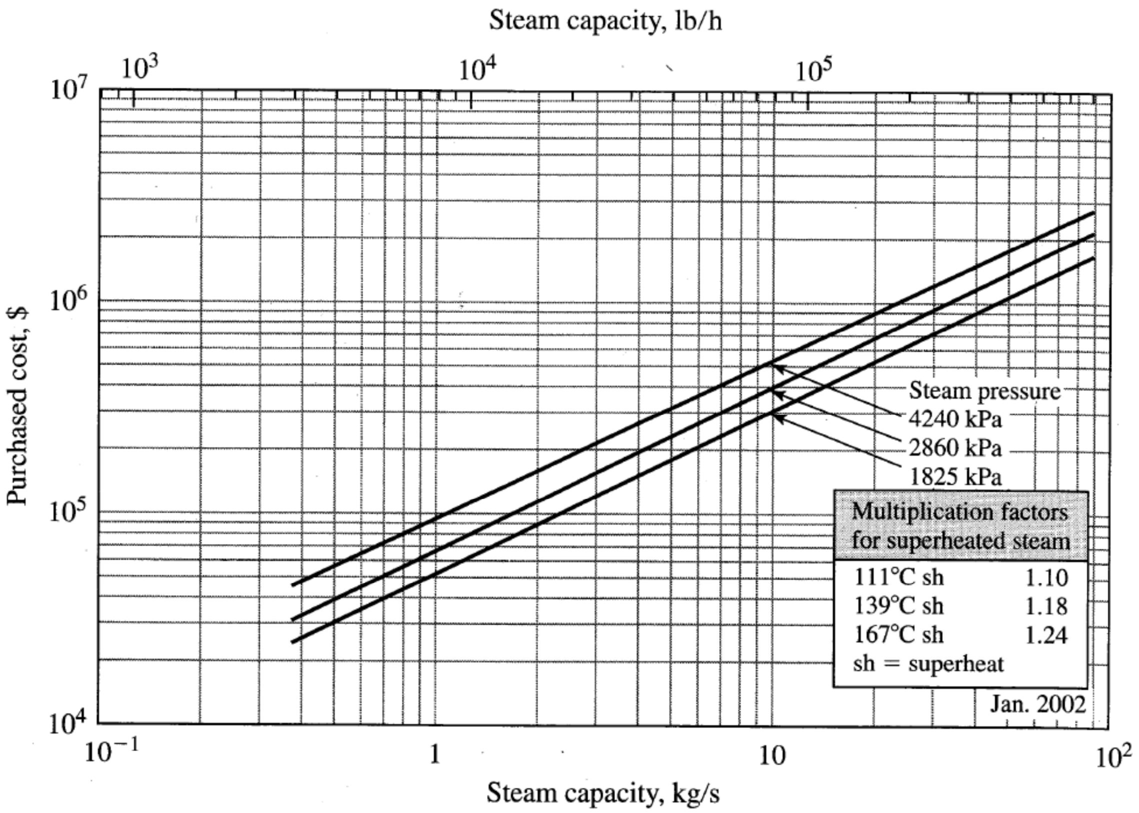

Figure A.4: Cost curve for boilers (Spath & Mann 2001)

Table A.68 shows the steam capacities and approximate costs for boiler plants of different sizes at 85% efficiency.

Table A.68: Steam capacities and approximate costs for different sized boilers

Boiler capacity (MW)	$\dot{m}_{steam}$ (kg/s)	Approximate cost (\$)	Fuel consumption (MJ/s)
1	0.6	45,000	1.8
10	6.6	300,000	11.8
30	19.7	700,000	35.3
50	32.8	800,000	58.8
120	78.7	2,000,000	141.2

A.32. Mining substitution impact indicator calculations

Step 1: Categorise material and cost data into environmental and economic impact categories

Table A.69: Environmentaland economic impact indicators for power and heating in mining using different fossil fuels

Option	Non-grid electricity			Heating		
Feedstock	Natural gas	Diesel	CSG	Natural gas	Diesel	CSG
Technology	IC	IC	IC	Boiler	Boiler	Boiler
Environmental impact indicators	**t/MWh**	**t/MWh**	**t/MWh**	**t/GJ_{heat}**	**t/GJ_{heat}**	**t/GJ_{heat}**
Global Warming Potential (GWP)	5.60E-01	6.75E-01	5.60E-01	6.04E-02	9.14E-02	6.04E-02
Acidification Potential (ADP)	1.14E-03	5.54E-03	1.14E-03	1.16E-05	5.46E-05	1.16E-05
Photochemical Oxidation Potential (POP)	2.75E-04	4.71E-04	2.75E-04	2.74E-06	3.01E-06	2.74E-06
Particulate Matter Formation (PMF)	3.06E-07	4.26E-04	3.06E-07	3.67E-06	3.97E-06	3.67E-06
Freshwater Withdrawal (FWW)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Saline Water Discharge (SWD)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Solid Waste Generation (SWG)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Economic impact indicators	**2012A$ /MWh**	**2012A$ /MWh**	**2012A$ /MWh**	**2012A$ /GJ_{heat}**	**2012A$ /GJ_{heat}**	**2012A$ /GJ_{heat}**
Annualised captial costs	6.4	4.4	6.4	0.2	0.2	0.2
Cash operating costs	97.9	299.5	89.7	26.3	59.5	25.2
Total operating costs	**104.3**	**303.9**	**96.1**	**26.5**	**59.7**	**25.4**

Step 2: Calculate the environmental and economic impacts resulting from substitution of natural gas

Table A.70: Environmentaland economic impacts due to substitution of naturla gas in the Australian mining sector

Option	Non-grid electricity		Heating	
Feedstock	NG→D	NG→CSG	NG→D	NG→CSG
Technology	IC	IC	Boiler	Boiler
Environmental impact indicators	**t/MWh**	**t/MWh**	**t/GJ_{heat}**	**t/GJ_{heat}**
Global Warming Potential (GWP)	1.15E-01	0.00E+00	3.10E-02	0.00E+00
Acidification Potential (ADP)	4.40E-03	0.00E+00	4.29E-05	0.00E+00
Photochemical Oxidation Potential (POP)	1.96E-04	0.00E+00	2.76E-07	0.00E+00
Particulate Matter Formation (PMF)	4.26E-04	0.00E+00	3.05E-07	0.00E+00
Freshwater Withdrawal (FWW)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Saline Water Discharge (SWD)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Solid Waste Generation (SWG)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Economic impact indicators	**2012A$/MWh**	**2012A$/MWh**	**2012A$/$GJ_{heat}$**	**2012A$/$GJ_{heat}$**
Annualised captial costs	4.4	-	0.2	-
Cash operating costs	201.6	-8.2	33.2	-1.0
Total operating costs	**206.0**	**-8.2**	**33.4**	**-1.0**

Step 3: Calculate annual environmental impacts

Assumptions:

- 9:1 split of natural gas in mining for electricity and heating
- 39% thermal efficiency for electricity generated from IC
- 85% thermal efficiency for heating from natural gas in boilers

Annual Australian mining electricity demand

$$= \left(\frac{4.60\times10^{6}t}{yr}\right)\left(\frac{51.34GJ}{1t}\right)\left(\frac{39}{100}\right)\left(\frac{1MWh}{3.6GJ}\right) = 25.6\text{x}10^{6}\ \text{MWh/yr}$$

Annual Australian mining heating demand

$$= \left(\frac{0.51\times10^{6}t}{yr}\right)\left(\frac{51.34GJ}{1t}\right)\left(\frac{10}{100}\right)\left(\frac{85}{100}\right) = 2.23\text{x}10^{6}\ \text{GJ/yr}$$

Table A.71: Annual environmental and economic impacts due to substitution of natural gas in the Australian mining sector

Option	Non-grid electricity		Heating	
Feedstock	NG→D	NG→CSG	NG→D	NG→CSG
Technology	IC	IC	Boiler	Boiler
Environmental impact indicators	**t/yr**	**t/yr**	**t/yr**	**t/yr**
Global Warming Potential (GWP)	2.95E+06	0.00E+00	6.92E+05	0.00E+00
Acidification Potential (ADP)	1.13E+05	0.00E+00	9.58E+02	0.00E+00
Photochemical Oxidation Potential (POP)	5.01E+03	0.00E+00	6.16E+00	0.00E+00
Particulate Matter Formation (PMF)	1.09E+04	0.00E+00	6.80E+00	0.00E+00
Freshwater Withdrawal (FWW)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Saline Water Discharge (SWD)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Solid Waste Generation (SWG)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Economic impact indicators	**2012A$/yr**	**2012A$/yr**	**2012A$/yr**	**2012A$/yr**
Annualised captial costs	112.8	0.0	5.1	0
Cash operating costs	5,158.0	-209.2	740.4	-21.8
Total operating costs	**5,270.8**	**-209.2**	**745.5**	**-21.8**

Step 4: Divide by natural gas substituted

Assumptions:

- 9:1 split of natural gas in mining for electricity and heating
- Higher heating value of 51.34 GJ/t and 44.07 GJ/t for natural gas/CSG and diesel/fuel oil.

Natural gas substituted in electricity generation = 4,599,991 t/yr

Natural gas substituted in heating = 511,110 t/yr

Table A.72: Substitution impact indicators for the Australian mining sector

Option	Non-grid electricity				Heating			
Feedstock	NG→D		NG→CSG		NG→D		NG→CSG	
Technology	Extraction and refining	IC	Extraction and refining	IC	Extraction and refining	Boiler	Extraction and refining	Boiler
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**
Global Warming Potential (GWP)	7.81E-02	7.60E-01	-1.14E-10	0.00E+00	7.81E-02	1.35E+00	-1.14E-10	0.00E+00
Acidification Potential (ADP)	7.52E-04	2.53E-02	-3.55E-10	0.00E+00	7.52E-04	1.87E-03	-3.55E-10	0.00E+00
Photochemical Oxidation Potential (POP)	4.16E-05	2.21E-03	-3.93E-09	0.00E+00	4.16E-05	1.20E-05	-3.93E-09	0.00E+00
Particulate Matter Formation (PMF)	1.14E-04	2.00E-03	-9.29E-11	0.00E+00	1.14E-04	1.33E-05	-9.29E-11	0.00E+00
Freshwater Withdrawal (FWW)	-1.01E-01	0.00E+00	-3.50E-12	0.00E+00	-1.01E-01	0.00E+00	-3.50E-12	0.00E+00
Associated Water Withdrawal (AWW)	1.35E-01	0.00E+00	1.44E-08	0.00E+00	1.35E-01	0.00E+00	1.44E-08	0.00E+00
Saline Water Discharge (SWD)	3.15E-04	0.00E+00	-7.17E-13	0.00E+00	3.15E-04	0.00E+00	-7.17E-13	0.00E+00
Solid Waste Generation (SWG)	2.33E-03	0.00E+00	6.95E-10	0.00E+00	2.33E-03	0.00E+00	6.95E-10	0.00E+00
Economic impact indicators	**2012A$/t NG substituted**		**2012A$/t NG substituted**		**2012A$/t NG substituted**		**2012A$/t NG substituted**	
Annualised captial costs	24.5		-		1.1		-	
Cash operating costs	1,121.3		-45.5		161		-4.7	
Total operating costs	**1,145.8**		**-45.5**		**162.1**		**-4.7**	

Step 5: Normalisation of environmental impacts

Table A.73: Normalised substitution impact indicators for the Australian mining sector

Option	Non-grid electricity		Heating	
Feedstock	NG→D	NG→CSG	NG→D	NG→CSG
Technology	IC	IC	Boiler	Boiler
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	1.32E-09	-1.14E-10	2.62E-09	-1.14E-10
Acidification Potential (ADP)	1.47E-08	-3.55E-10	1.53E-09	-3.55E-10
Photochemical Oxidation Potential (POP)	1.02E-08	-3.93E-09	4.86E-10	-3.93E-09
Particulate Matter Formation (PMF)	2.99E-09	-9.29E-11	1.54E-10	-9.29E-11
Freshwater Withdrawal (FWW)	-1.23E-12	-3.50E-12	-1.23E-12	-3.50E-12
Associated Water Withdrawal (AWW)	4.31E-10	1.44E-08	4.31E-10	1.44E-08
Saline Water Discharge (SWD)	5.02E-15	-7.17E-13	5.02E-15	-7.17E-13
Solid Waste Generation (SWG)	3.76E-11	6.95E-10	3.76E-11	6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised captial costs	24.5	-	1.1	-
Cash operating costs	1,121.3	-45.5	161	-4.7
Total operating costs	**1,145.8**	**-45.5**	**162.1**	**-4.7**

A.33. Adjustment of export steam from steam reforming plant literature

Spath and Mann (2001) reported that a 1.5 million Nm^3/day (or 5.62 t/hr) SMR H_2 plant produces 1,858 t/day (77.42 t/h) of 263°C and 4.8 MPa (700 psi) export steam. This is equivalent to 13.78 t steam/t H_2 or 77.42 t steam/hr. In order to estimate the equivalent flowrate of steam used in the analysis (310°C and 10,000 kPa), a HYSYS model is constructed as shown in Figure A.5.

Procedure

1. The export steam from Spath and Mann (2001) at 263°C and 4.8 MPa is brought to the temperature and pressure of the boiler feedwater at 310°C and 10,000 kPa.
2. 77.42 t/h of steam at 263°C and 4.8 MPa (SMRLiterature1) is fed into a compressor (SMRComp1) to increase its pressure to 10,000 kPa. The compressor requires a duty of 4.737 MW.
3. Heat is removed from the steam (SMRLiteraurtre2) to form saturated water at 310°C and 10,000 kPa (SMRLiterature3) using a heater (SMRHX1). The heater removes 34.79 MW of heat.
4. The net energy available to produce steam is (34.79 – 4.737) MW = 30.06 MW
5. This net energy is used to convert saturated water (SMRSteam1) to saturated steam (SMRSteam2) at 310°C and 10,000 kPa. 79.88 t/h of steam is produced.

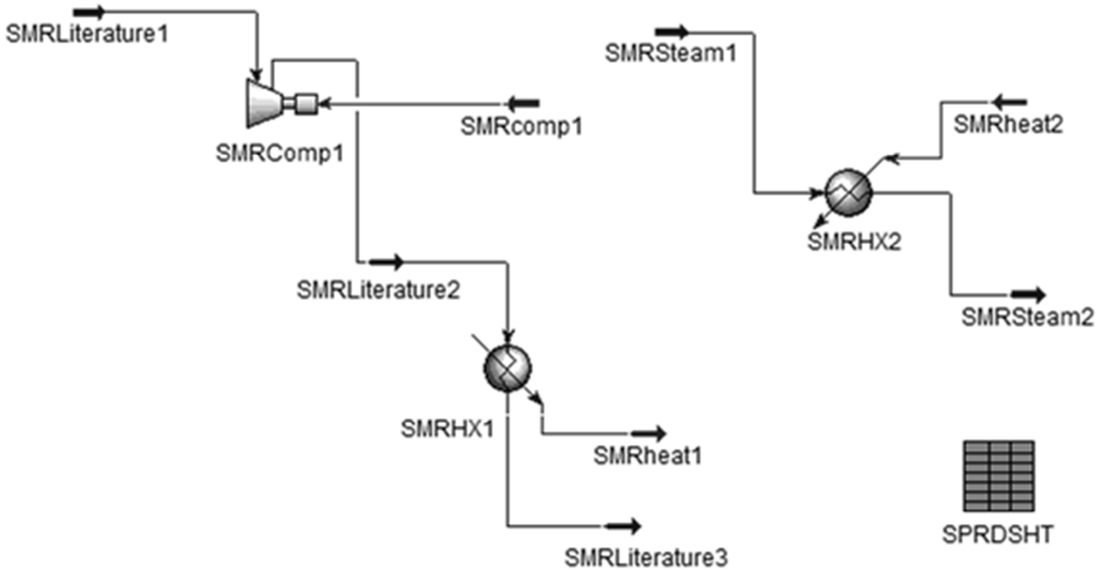

Figure A.5: HYSYS simulation of steam cycle in SMR H_2 plant.

Given that the SMR hydrogen plant in Spath and Mann (2001) produces 5.62 t/h of H_2, the steam-to-H_2 produced is (79.88/5.62) = 14.21 t steam/t H_2.

A.34. SMR plant environmental flows literature comparison

The material data for hydrogen production using SMR in Table A.74 were assembled from various sources (Spath & Mann 2001, Boyce et al. 2004, Rutkowski 2012, Linde 2014). The natural gas usage was between 3 to 3.23 t/t H_2 for all sources with the exception of Boyce et al. (2004) which reported the natural gas requirement of a modern SMR hydrogen plant to be 4.19 t/t H_2. There was also a large difference in reported water usage for all sources. The demineralised water consumption to generate steam for the reforming and shift reactions was the most consistent and ranged between 4.8 to 5.47 t/t H_2. The cooling water usage varied from 5.67 to 35.6 t/t H_2, with the highest cooling water usage recorded by Linde (2014). Although not specified in the literature, the difference may be due to whether the cooling water figure reported is for the cooling water flowrate or the cooling water makeup. The cooling water flowrate is reported if the amount of cooling water required for cooling duty is of interest. The quantity remains almost the same regardless of the type of cooling water system chosen. If the system is a recirculated cooling water system, normally the makeup water is reported as the input for the plant. The makeup water normally makes up a small percentage of the cooling water flowrate. The nature and extent of heat recovery, as well as external conditions such as climate, may affect the cooling water required. The demineralised water consumed to generate export steam ranged from 6.9 to 16.0 t/t H_2. This will vary depending on the desired amount of export steam specified in the literature. Out of the sources, the material data from Rutkowski (2012) were chosen to represent the SMR hydrogen plant in this analysis as the information was more recent than that reported by Spath et al. (2001) and Boyce et al. (2004).

Table A.74: Material flow data for hydrogen production via steam methane reforming from various literature

Inventory data	Units	Spath et al. (2001)	Boyce et al. (2004)	Rutkowski (2012)	Linde (2014)
Input					
Electricity	MWh/t H_2	2.94E-01	2.00E-01	5.69E-01	1.89E-01
Natural gas feedstock	t/t H_2	2.70	3.00	3.21	3.23
Natural gas fuel	t/t H_2	3.00E-01	1.19	Included above	Included above
Cooling water	t/t H_2	n/a	11.9	5.67	35.6
Deminaralised water	t/t H_2	18.80	21.4	12.7	12.37
Consumption					
Process steam	t/t H_2	4.80	5.35	12.7	5.47
Output					
Export steam	t/t H_2	14.0	16.0	Included above	6.9
CO_2	t/t H_2	8.89	n/a	7.94	n/a
CO	t/t H_2	7.98E-05	n/a	n/a	n/a
NO_x	t/t H_2	8.98E-04	n/a	9.91E-04	n/a
PM_{10}	t/t H_2	2.20E-05	n/a	n/a	n/a

Only Spath et al. (2001) and Rutkowski (2012) provided emission data for hydrogen plants. Spath et al. (2001) reported the emissions of CH_4, N_2O, VOC and SO_2 from hydrogen plants to be negligible with respect to the emissions over the whole life cycle.

A.35. SMR plant cost data

This section outlines the hydrogen plant data used to plot Figure 4.28 and their sources.

Literature data

Table A.75: SMR plant data from literature

No	Location	Capacity (t/yr)	Original capital cost	Adjusted capital cost (2012A$)	Ref
1	Australia	10,950	1996A$ 29 million	$45 million	[A]
2	US	43,281	2002US$ 30 million	$78 million	[B]
3	US	54,750	2002US$ 47 million	$123 million	[C]
4	US	87,896	1998US$ 65 million	$169 million	[D]
5	US	138,476	2005US$ 135 million	$227 million	[E]
6	US	152,497	2000US$ 131 million	$341 million	[F]

References

[A] Sinclair, S. (1996). CHE 4117 Design project: Altona refinery natural gas hydrogen plant, Monash University.

[B] Molburg, John C., Doctor, Richard D. (2003). Hydrogen from steam-methane reforming with CO_2 capture. 20th Annual International Pittsburgh Coal Conference. Pittsburgh, PA.

[C] Simbeck, D. R. and Chang, E. (2002). Hydrogen supply: Cost estimate for hydrogen pathways – Scoping analysis. Mountain View, California, NREL.

[D] Gray, D. and Tomlinson, G. (2001). Hydrogen from coal, Center for Science and Technology.

[E] Rutkowski, Mike D. (2012). Current (2010) hydrogen from natural gas without CO_2 capture and sequestration, NREL.

[F] Klett, M. G., White, J. S., Schoff, R. L. and Buchanan, T. S. (2002). Hydrogen production facilities plant performance and cost comparisons. J. R. Longanbach. Reading, Pennsylvania, Parsons Infrastructure and Technology Group Inc.

Actual plant data

Table A.76: Actual SMR plant data

No	Company	Plant name	Location	Capacity (t/yr)	Original capital cost	Adjusted capital cost (2012A$)	Ref
7	Thyssen Krupp Uhde GmbH	Koch-Glitsch	Novopolotsk, Belarus	30,709	2003€ 8 million	$16 million	[A][B][C]
8	Air Products and Chemicals	Carson	California, US	87,896	2000US$ 80 million	$115 million	[C]
9	Thyssen Krupp Uhde GmbH	Neste Oil Porvoo Refinery	Finland	120,868	2006€ 25 million	$40 million	[A][D]

References

[A] ThyssenKrupp (2014). "Products & solutions - References - Chemical industry - Hydrogen." 5 December 2013. http://www.thyssenkrupp-industrial-solutions.com/products-solutions/references/chemical-industry/hydrogen.html.

[B] ICIS News (2003). "Uhde to build Belarus hydrogen plant for Koch-Glitsch." http://www.icis.com/Articles/2003/01/09/187647/uhde-to-build-belarus-hydrogen-plant-for-koch-glitsch.html.

[C] PR Newswire (n.d.). "Air Products brings Carson, California hydrogen plant on-stream." http://www.prnewswire.com/news-releases/air-products-brings-carson-california-hydrogen-plant-on-stream-72374327.html.

[D] Kable (2014). Neste Oil Porvoo Refinery Diesel Project, Porvoo, Finland. http://www.hydrocarbons-technology.com/projects/fortum/.

A.36. Adjustment of export steam from coal gasification plant literature

Buchanan et al. (2003) designed a coal to H_2 plant which co-produces electricity. The heat recovered from the gasifier produces enough feedstock steam for the shift reaction and steam at 951.2°F (510.7°C) and 1264 psia (8715kPa) which is fed into a steam turbine. The configuration of the coal to hydrogen is modified so that it produces export steam instead of electricity. The steam turbine is removed and 560,222 lb/hr (254.1 t/h) of steam at 510.7°C and 8715kPa is available for export. In order to estimate the equivalent flowrate of steam used in the analysis (310°C and 10,000 kPa), a HYSYS model is constructed as shown in Figure A.6.

Procedure

1. The steam from Buchanan et al. (2003) at 510.7°C and 8715kPa is brought to the temperature and pressure of the boiler feedwater at 310°C and 10,000 kPa.
2. 254.1 t/h of steam at 510.7°C and 8715kPa (CGLiterature1) is fed into a compressor (CGComp1) to increase its pressure to 10,000 kPa. The compressor requires a duty of 4.392 MW.
3. Heat is removed from the steam (CGLiterautre2) to form saturated water at 310°C and 10,000 kPa (CGLiterature3) using a heater (CGHX1). The heater removes 140.4 MW of heat.
4. The net energy available to produce steam is (140.4 – 4.392) MW = 136.0 MW
5. This net energy is used to convert saturated water (CGSteam1) to saturated steam (CGSteam2) at 310°C and 10,000 kPa. 361.4 t/h of steam is produced.

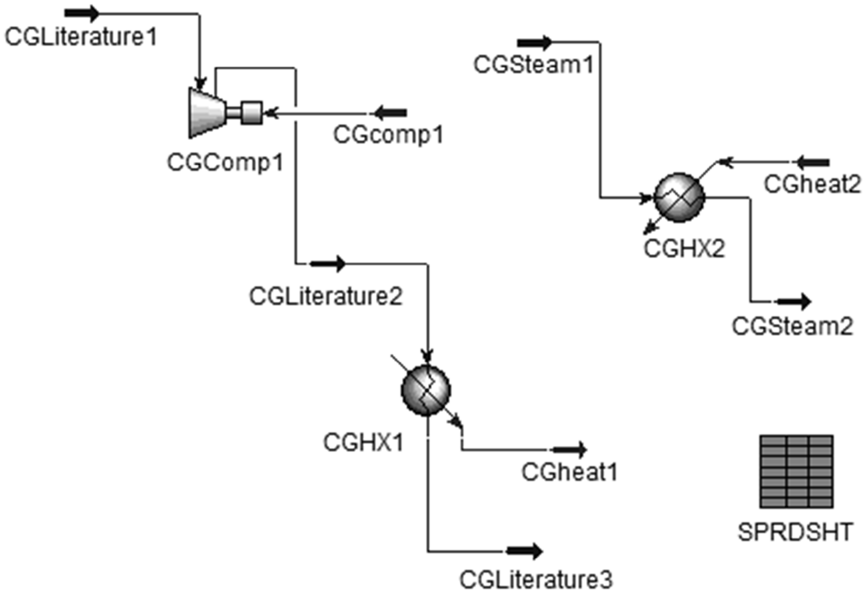

Figure A.6: HYSYS simulation of steam cycle in coal gasification (CG) H_2 plant

Given that the SMR hydrogen plant in Buchanan et al. (2003) produces 26,049 lb/h or 21.5 t/h of H_2, the steam-to-H_2 produced is (361.4/21.5) = 16.81 t steam/t H_2.

A.37. Coal-to-hydrogen plant mass balance

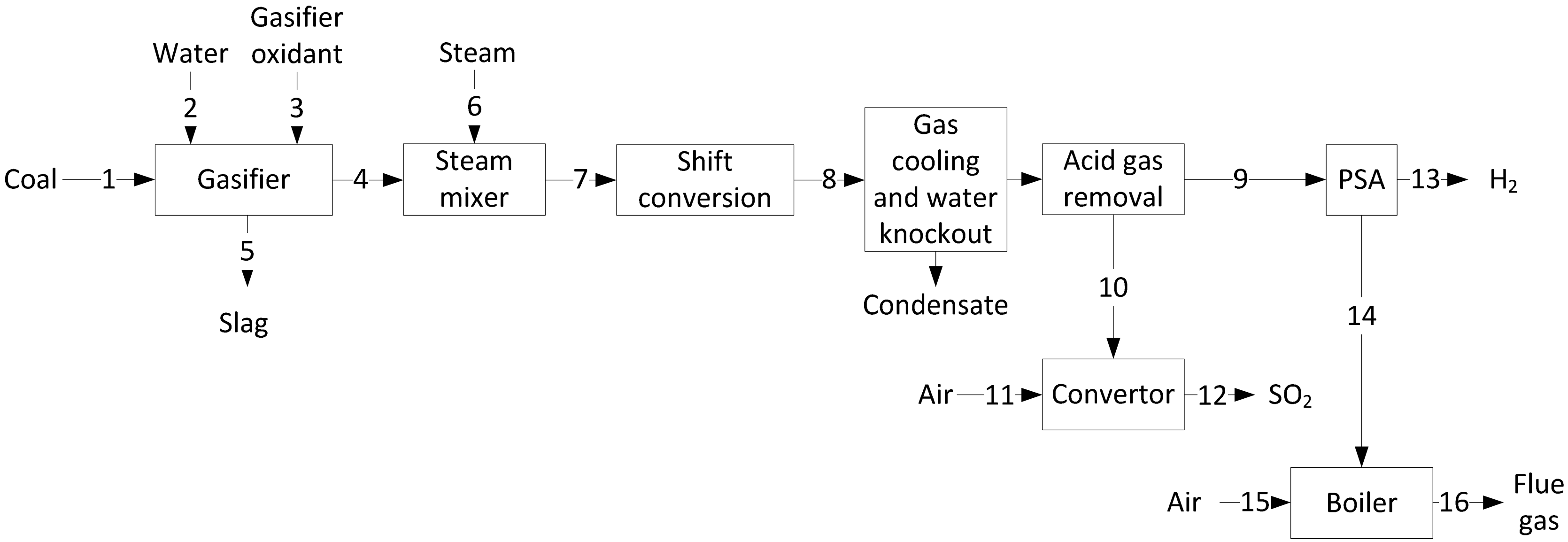

Figure A.7: Coal-to-hydrogen plant flow diagram

Coal-to-hydrogen material balance is taken from Buchanan et al. (Buchanan et al. 2003). U.S. Pittsburgh No.8 coal is used as the feedstock (see Appendix A.27 for U.S. coal properties). This coal is replaced with Australian reference coal (see Chapter 0).

- For the gasifier, the individual components of the gasifier product are adjusted according to the coal composition. e.g. The ratio of CH_4, CO, CO_2 and COS are assumed to be linked to the amount of C in the coal.
- Convertors (e.g. shift and SO_2 convertors) and fuel burners (e.g. PSA offgas burner) have the same conversion rates in %.
- The acid gas removal and PSA units have the same removal rates in %.

Table A.77: Mass balance for H_2 plant using No. Pittsburgh coal (NETL 2010a)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Mass flow rate (t/hr)	101.0	42.6	81.1	229	10.3	149	334	378	196	60.4	19.7	80.1	11.8	185	237	422
Temperature (°C)	-	15.6	158	260	-	260	260	458	50.6	50.6	166	399	21.1	21.1	31.7	138
Pressure (MPa, abs)	0.101	0.101	4.27	2.70	0.103	3.24	2.70	2.63	2.33	2.33	0.310	0.300	2.14	0.117	0.117	0.101
Mole fraction (%)																
Ar	-	0	0.04	0.01	-	0	0	0	0.01	0	0.01	0	0	0.01	0.01	0.01
CH_4	-	0	0	0	-	0	0	0		0	0	0	0	0.01	0	0
CO	-	0	0	0.42	-	0	0.24	0.06	0.10	0	0	0	0	0.20	0	0
CO_2	-	0	0	0.10	-	0	0.06	0.24	0.27	0.94	0	0.64	0	0.53	0	0.34
H_2	-	0	0	0.33	-	0	0.19	0.38	0.61	0	0	0	1.00	0.24	0	0
H_2O	-	1.00	0	0.12	-	1.00	0.49	0.31		0	0.01	0.05	0	0.01	0.01	0
H_2S	-	0	0	0.01	-	0	0	0		0.06	0	0	0	0	0	0.13
HCl	-	0	0	0	-	0	0	0		0	0	0	0	0	0	0
N_2	-	0	0.01	0.01	-	0	0	0	0.01	0	0.77	0.26	0	0.01	0.77	0.49
NH_3	-	0	0	0	-	0	0	0		0	0	0	0	0	0	0
O_2	-	0	0.95	0	-	0	0	0		0	0.21	0	0	0	0.21	0.02
SO_2	-	0	0	0	-	0	0	0	0	0	0	0.05	0	0	0	0
Total	-	1.00	1.00	1.00	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Mass of Pittsburgh No.8 coal	= 101 t/hr
Hydrogen produced	= 11.8 t/hr
CO_2 produced	= 21.5 t/t H_2
SO_2 produced	= 0.481 t/t H_2 (prior to conversion into H_2SO_4)
CO produced	= 9.63×10^{-4} t/t H_2

Table A.78: Mass balance for H_2 plant using Australian black coal (AGO 2006)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Mass flow rate (t/hr)	101.0	36.8	64.5	200	17.6	149	334	334	51.7	184	3.41	188	11.4	40.3	222	262
Temperature (°C)	-	15.6	158	260	-	260	260	458	50.6	50.6	166	399	21.1	21.1	31.7	138
Pressure (MPa, abs)	0.101	0.101	4.27	2.70	0.103	3.24	2.70	2.63	2.33	2.33	0.310	0.300	2.14	0.117	0.117	0.101
Mole fraction (%)																
Ar	-	0	0.04	0.01	-	0	0.01	0.01	0.01	0	0.01	0	0	0.03	0.01	0.02
CH_4	-	0	0	0	-	0	0	0	0.01	0	0	0	0	0.02	0	0
CO	-	0	0	0.41	-	0	0.24	0.06	0.13	0	0	0	0	0.39	0	0
CO_2	-	0	0	0.09	-	0	0.06	0.23	0.01	1.00	0	1.00	0	0.02	0	0.13
H_2	-	0	0	0.36	-	0	0.21	0.39	0.84	0	0	0	1.00	0.52	0	0
H_2O	-	1.00	0	0.12	-	1.00	0.48	0.30	0	0	0.01	0	0	0.01	0.01	0
H_2S	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0	0.18
HCl	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0	0
N_2	-	0	0.01	0.01	-	0	0	0.01	0.01	0	0.77	0	0	0.02	0.77	0.65
NH_3	-	0	0	0	-	0	0	0	0	0	0	0	0	0	0	0
O_2	-	0	0.95	0	-	0	0	0	0	0	0.21	0	0	0	0.21	0.03
SO_2	-	0	0	0	-	0	0	0	0	0	0	0.05	0	0	0	0
Total	-	1.00	1.00	1.00	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Mass of Australian reference coal = 101 t/hr

Hydrogen produced = 11.4 t/hr

CO_2 produced = 20.6 t/t H_2

SO_2 produced = 0.0799 t/t H_2 (prior to conversion into H_2SO_4)

CO produced = 8.86×10^{-4} t/t H_2

A.38. Hydrogen from coal environmental flows literature comparison

The data in Table A.79 summarises the various inputs and outputs of a coal gasification hydrogen plant from various sources (Bechtel Corporation et al. 2003, Leonard M. Bartone et al. 2007, Rutkowski 2008). For comparison, the LCA data for IGCC from NETL (2010) was included.

Table A.79: Material flow data for hydrogen production via coal gasification from various literature

Inventory data	Units	Bechtel (2003)	Buchanan et al. (2003)/Rutkowski (2005)	Leonard et al. (2007)	Dufour et al. (2011)	NETL IGCC LCA (2010)
Input						
Electricity	MWh/t H_2	6.28	3.46	2.94	1.45	-
Black coal	t/t H_2	8.84	8.51	8.51	4.34	8.51
Cooling water	t/t H_2	-[a]	-	7.36	9.12	33.2
Process water	t/t H_2	39.4	11.3	5.51	11.6	-
Output						
Electricity	MWh/t H_2	4.98	6.64	-	2.29	-
Wastewater	t/t H_3	2.08E-01	1.30E-01	1.74	-	-
CO_2	t/t H_2	20.3	21.4	20.0	-	1.77E+01
CH_4	t/t H_2	-	0	-	-	6.73E-05
N_2O	t/t H_2	-	-	-	-	7.75E-08
VOC	t/t H_2	-	-	-	-	4.76E-07
CO	t/t H_2	5.84E-02	1.08E-03	-	-	8.84E-06
NO_x	t/t H_2	8.58E-04	-	-	2.16E-02	5.21E-03
SO_2	t/t H_2	6.07E-03	2.42E-03	4.36E-04	3.46E-02	1.20E-03
PM	t/t H_2	-	-	-	8.90E-02	6.80E-04
Ash	t/t H_2	1.18	7.38E-01	1.23E+00	-	-

[a] Possibly included in the total water usage reported, which was assumed to be in the process water category.

Bechtel (2003) developed and optimised a coal to hydrogen plant (located under Subtask 1.7) using the Wabash River coal gasification repowering project as the starting point. Dry Illinois No. 6 coal was used and the composition and heating values of this coal can be found in Appendix A.27. Bechtel (2003) reported that a coal-to-hydrogen plant will have higher emission levels of CO, lower emission levels of CO_2, NO_x (as NO_2) and SO_2, and lower water usage when compared to an IGCC plant with a similar sized gasifier. Both plants produce the same amount of slag. According to Bechtel (2003), the slag is 15% water and the remaining 85% was assumed to be solid material or ash for the purpose of this analysis. As the full slurry quench cooling method was used and some water-soluble components will dissolve in the water, this slag water will be treated as wastewater which will require treatment. Bechtel (2003) used the PSA tail gas as fuel for steam generation, which was used to generate power using steam turbine. Approximately 5 MWh/t H2 was produced to partially offset the electricity requirements of the plant, which was 6.3 MWh/t H_2.

Buchanan et al. (2003) and Rutkowski (2008) provided mass balances and properties of the coal feedstock used in a central distribution hydrogen plant. The properties of the Pittsburgh No. 8 coal can be found in Appendix A.27. The input values of coal feedstock and process water were provided, as well as output values of CO, CO_2, SO_2 and slag, which was assumed to be 15% water and 85% ash similar to Bechtel (2003). Rutkowski (2008) reported a value of 11.3 t/t H_2 for the process water requirements, which is sufficient for the gasification process in addition to meeting other steam demands across the plant. Rutkowski (2008) included a steam turbine generator in the plant capital costs, indicating that the HRSG fuelled by PSA tail gas was used to produce steam for the steam turbine to generate electricity. A net production of 3.18 MWh/t H_2 was reported.

Leonard et al. (2007) provided usage data for a syngas from coal plant with co-production of hydrogen (ratio of 44:1 on mass basis). The study revealed the breakdown of cooling water consumption for both the gasifier and the ASU unit which were not reported in Bechtel (2003) and Rutkowski (2008). The ASU unit was also revealed to be the most power-intensive equipment in the plant as it made up more than 65% of the total plant electricity demand. In addition to coal feedstock, the gasification process also consumes relatively small amounts of natural gas as a supplementary fuel. For gasification systems using quench cooling, a natural gas ring burner was installed at the bottom of the gasifier "to maintain the temperature of the slag pool in the hearth, to prevent tap blockage and to consume any remaining coke particles" (Leonard M. Bartone et al. 2007). Approximately 1.5 t natural gas was combusted in the gasifier's ring burner for every 1000 t coal fed into the gasifier. Another use of natural gas was in the auxiliary boiler for start-up, where approximately 0.47 t natural gas was consumed for every 1000 t coal feedstock (Griffing & Overcash 2010). In the event of a natural gas scarcity, a substitute fuel was required to replace the natural gas, such as diesel fuel oil. The usage data of the syngas and hydrogen plant from Leonard et al. (2007) were adjusted to reflect a pure hydrogen plant with a gasifier of the same size by converting the units to the basis of usage per tonne of coal feedstock consumed in the gasification process. Then, the units were multiplied with the coal consumption per tonne of hydrogen product from Rutkowski (2008). When converting from a syngas and hydrogen plant to a pure hydrogen plant, the demand for process water to produce steam will be higher and will approach that reported by Rutkowski (2008). Given that the hydrogen production was 771 kg/hr, it can be estimated that 6940 t/hr out of 10136 t/hr of the process water makeup was used to react with coal to produce hydrogen, and the remainder will replace an equivalent amount exiting the system as wastewater. The wastewater is the result of steam being used in strippers throughout the process to regenerate solvents and remove impurities. Thus, for a pure hydrogen plant, the wastewater production can be approximated to be 1.74 t/t H_2. Steam is also used to heat up process streams. The cooling water demand, however, was not expected to change for the conversion to a pure hydrogen plant.

Dufour et al. (2011) reported the mass and energy balances of hydrogen produced from coal gasification, but the results included electricity consumption for CCS compression, resulting in a net export electricity was 0.8 MWh/t H_2. Ruether et al. (2005) reported that a coal to hydrogen plant with CCS will produce a net export power of 0.9 MWh/t H_2 while a non-CCS coal to hydrogen plant will produce a higher net export power of 2.9 MWh/t H_2, which is close to 3.18 MWh/t H_2 reported by Rutkowski (2008). The process water consumption of 11.6 t/t H_2 reported by Dufour et al. (2011) was also similar to the value of 11.3t/t H_2 reported by Rutkowski (2008). However, the coal consumption value of 4.34 t/t H_2 was half that found in other literature and emissions of NO_x, SO_2 and particulates were higher than average, although these emissions were quoted as emissions from a coal gasifier.

A.39. Coal gasification plant cost data

Literature data

Table A.80: Coal gasification plant cost data from literature

No	Location	Capacity (t/yr)	Original capital cost	Adjusted capital cost (2012A$)	Ref
1	US	49,275	2002A$ 145 million	$377 million	[A]
2	US	93,238	2005US$ 313 million	$526 million	[B]
3	US	97,872	1998US$ 271 million	$703 million	[C]
4	US	114,099	2000US$ 264 million	$689 million	[D]

References

[A] Simbeck, D. R. and Chang, E. (2002). Hydrogen supply: Cost estimate for hydrogen pathways – Scoping analysis. Mountain View, California, NREL.

[B] Rutkowski, Mike D. (2012). Current (2010) hydrogen from natural gas without CO_2 capture and sequestration, NREL.

[C] Gray, D. and Tomlinson, G. (2001). Hydrogen from coal, Center for Science and Technology.

[D] Klett, M. G., White, J. S., Schoff, R. L. and Buchanan, T. S. (2002). Hydrogen production facilities plant performance and cost comparisons. J. R. Longanbach. Reading, Pennsylvania, Parsons Infrastructure and Technology Group Inc.

A.40. Hydrogen substitution impact indicator calculations

Step 1: Categorise material flow data into environmental and economic impact categories

Table A.81: Environmental impacts for hydrogen production from different fossil fuels

Option	Hydrogen		
Feedstock	NG	BlC	CSG
Technology	SMR	CG	SMR
Environmental impact indicators	**t/t H_2**	**t/t H_2**	**t/t H_2**
Global Warming Potential (GWP)	9.13E+00	2.33E+01	9.13E+00
Acidification Potential (ADP)	5.23E-04	8.83E-02	5.23E-04
Photochemical Oxidation Potential (POP)	9.69E-05	3.67E-04	9.69E-05
Particulate Matter Formation (PMF)	1.03E-04	1.19E-03	1.03E-04
Freshwater Withdrawal (FWW)	2.65E+01	5.08E+01	3.18E+01
Saline Water Discharge (SWD)	1.97E+00	4.40E+00	2.22E+00
Solid Waste Generation (SWG)	3.07E-02	1.84E+00	3.07E-02
Economic impact indicators	**2012A$mil/t H_2**	**2012A$mil/t H_2**	**2012A$mil/t H_2**
Annualised captial costs	255.5	681.2	255.5
Cash operating costs	551.7	750.3	400.8
Total operating costs	**807.2**	**1,431.4**	**656.2**

Step 2: Calculate the environmental and economic impacts resulting from substitution of natural gas

Table A.82: Environmental impacts due to substitution of natural gas in hydrogen production in Australia

Option	Hydrogen	
Feedstock	NG→BlC	NG→CSG
Technology	SMR→CG	SMR
Environmental impact indicators	**t/t H_2**	**t/t H_2**
Global Warming Potential (GWP)	1.41E+01	0.00E+00
Acidification Potential (ADP)	8.77E-02	0.00E+00
Photochemical Oxidation Potential (POP)	2.70E-04	0.00E+00
Particulate Matter Formation (PMF)	1.09E-03	0.00E+00
Freshwater Withdrawal (FWW)	2.43E+01	0.00E+00
Saline Water Discharge (SWD)	2.43E+00	0.00E+00
Solid Waste Generation (SWG)	1.81E+00	0.00E+00
Economic impact indicators	**2012A$mil/t H_2**	**2012A$mil/t H_2**
Annualised captial costs	681.2	0.0
Cash operating costs	198.5	-151.1
Total operating costs	**879.7**	**-151.1**

Step 3: Calculate annual environmental impacts

Annual Australian hydrogen production = 3 x 10^5 tonnes

Table A.83: Annual environmental impacts due to substitution of natural gas in Australia's hydrogen production

Option	Hydrogen	
Feedstock	NG→BlC	NG→CSG
Technology	SMR→CG	SMR
Environmental impact indicators	**t/yr**	**t/yr**
Global Warming Potential (GWP)	4.24E+06	0.00E+00
Acidification Potential (ADP)	2.63E+04	0.00E+00
Photochemical Oxidation Potential (POP)	8.11E+01	0.00E+00
Particulate Matter Formation (PMF)	3.26E+02	0.00E+00
Freshwater Withdrawal (FWW)	7.29E+06	0.00E+00
Saline Water Discharge (SWD)	7.29E+05	0.00E+00
Solid Waste Generation (SWG)	5.43E+05	0.00E+00
Economic impact indicators	**2012A$mil/yr**	**2012A$mil/yr**
Annualised captial costs	204.3	0.0
Cash operating costs	59.6	-45.3
Total operating costs	**263.9**	**-45.3**

Step 4: Divide by natural gas substituted

Natural gas substituted in hydrogen production = 9.6 x 10^5 tonnes

Table A.84: Substitution impact indicators for hydrogen production in Australia

Option	Hydrogen			
Feedstock	NG→BlC		NG→CSG	
Technology	Extraction and refining	SMR→CG	Extraction and refining	SMR
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**
Global Warming Potential (GWP)	-1.08E-01	4.39E+00	-6.23E-02	0.00E+00
Acidification Potential (ADP)	-6.01E-04	2.72E-02	-6.08E-04	0.00E+00
Photochemical Oxidation Potential (POP)	-2.65E-04	8.39E-05	-4.34E-04	0.00E+00
Particulate Matter Formation (PMF)	-3.65E-05	3.38E-04	-7.71E-05	0.00E+00
Freshwater Withdrawal (FWW)	4.36E-02	7.55E+00	-2.88E-01	0.00E+00
Associated Water Withdrawal (AWW)	-2.83E-01	0.00E+00	4.51E+00	0.00E+00
Saline Water Discharge (SWD)	-2.02E-02	7.54E-01	-4.51E-02	0.00E+00
Solid Waste Generation (SWG)	1.06E+01	5.62E-01	4.30E-02	0.00E+00
Economic impact indicators	**2012A$/t NG substituted**		**2012A$/t NG substituted**	
Annualised captial costs	211.5		-	
Cash operating costs	61.7		-46.9	
Total operating costs	**273.2**		**-46.9**	

Step 5: Normalisation of environmental impacts

Table A.85: Normalised substitution impact indicators for hydrogen production in Australia

Option	Hydrogen	
Feedstock	NG→BlC	NG→CSG
Technology	SMR→CG	SMR
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	7.84E-09	-1.14E-10
Acidification Potential (ADP)	1.56E-08	-3.55E-10
Photochemical Oxidation Potential (POP)	-1.64E-09	-3.93E-09
Particulate Matter Formation (PMF)	3.63E-10	-9.29E-11
Freshwater Withdrawal (FWW)	9.23E-11	-3.50E-12
Associated Water Withdrawal (AWW)	-9.04E-10	1.44E-08
Saline Water Discharge (SWD)	1.17E-11	-7.17E-13
Solid Waste Generation (SWG)	1.80E-07	6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised captial costs	211.5	-
Cash operating costs	61.7	-46.9
Total operating costs	**273.2**	**-46.9**

A.41. Literature data for ammonia plants

Table A.86 includes material flow data for ammonia production from various literature, including data from NPI (2013a) and EPA (2001).

EFMA (2000) reported emissions for the Best Available Technique (BAT) ammonia production in Europe, which were most effective in achieving a high general level of protection for the environment as a whole. For ammonia production using natural gas as a feedstock, the conventional Uhde steam reforming method was selected as the BAT. CO_2 is the product for the both steam reforming of natural gas (1.3 t/t NH_3) and combustion of natural gas (0.5 t/t NH_3) in the primary reformer. The flue gas from the primary reformer will also produce CO, NO_2 and SO_2 emissions. The CO and SO_2 emissions were expected to be less than $3x10^{-5}$ t/t NH_3 and $1x10^{-5}$ t/t NH_3 respectively. The NO_x emissions can range from $6x10^{-4}$ to $1.3x10^{-3}$ t/t NH_3, but for new plants an emission level of $4.5x10^{-4}$ t/t NH_3 was achievable. The BAT ammonia process was reported to not produce any solid waste, but spent catalysts and other waste material make up less than $2x10^{-4}$ t/t NH_3.

NPI data of ammonia production facilities are classified under the “Fertiliser and pesticide manufacturing” category and the emission-reporting boundary encompasses the whole facility rather than just the single ammonia plant (e.g. CSBP’s Kwinana ammonium nitrate operations and Gibson Island urea operations). One standalone ammonia plant is Yara Pilbara’s ammonia plant located at the Burrup peninsula in Western Australia. Recent NPI data was reported for this plant and a 2001 EPA report was published. Both sources reported the Yara Pilbara ammonia plant to have higher CO emissions and lower NO_x and SO_2 emissions than that reported by EFMA (2000). The natural gas consumption and greenhouse gas emissions that were found in the EPA report was found to be identical to that of the BAT.

Table A.86: Material flow data for ammonia production via Uhde steam methane reforming from various literature

Inventory data	Units	EFMA (2000)	Yara Pilbara ammonia plant (NPI 2012)	Burrup ammonia plant (EPA 2001)	NPI emission factors (2004)
Input					
Electricity	MWh/t NH_3	-	-	-	-
Natural gas feedstock	t/t NH_3	0.48	-	0.66	-
Natural gas fuel	t/t NH_3	0.19	-	Included above	-
Cooling water	t/t NH_3	-	-	17.2 [a]	-
Process water	t/t NH_3	1.50 [b]	-	1.09E-05 [c]	-
Output					
CO_2	t/t NH_3	1.80	-	1.83	-
CH_4	t/t NH_3	-	-	-	-
N_2O	t/t NH_3	-	-	-	-
VOC	t/t NH_3	-	2.24E-05	0	3.69E-03
CO	t/t NH_3	3.00E-05	1.29E-03	1.30E-04	7.90E-03
NO_x	t/t NH_3	1.30E-03	1.41E-04	6.50E-04	-
SO_2	t/t NH_3	1.00E-05	6.35E-08	8.00E-07	2.88E-05
PM_{10}	t/t NH_3	-	3.06E-05	1.22E-05	-
Solid waste	t/t NH3	2.00E-04	-	2.94E-05	-

[a] Direct cooling using seawater

[b] Process steam consumption

[c] Makeup water to replace blowdown

A.42. Air separation unit (ASU)

Morgan (2013) calculated the power requirements for the ASU of a 300 t/day ammonia plant, which was solely for the compression train used at the inlet. Equation A.7 was used to determine the fluid power required.

$$\dot{W}_{fluid} = T_{in} N \frac{n}{(n-1)} R\dot{m} \left\{ \left[\left(\frac{P_2}{P_1} \right)^{\frac{1}{N}} \right]^{\left(\frac{n-1}{n} \right)} - 1 \right\} \qquad (\text{Equation A.7})$$

where T_{in} is the temperature of the feed entering the compressor train in K; *N* is the number of stages in the compression train; *n* is the polytropic exponent; *R* is the specific gas constant in kJ/kg.K; $\dot{m}$ is the mass flow rate in kg/s; P_2 is the final pressure in bar; P_1 is the initial pressure in bar.
The assumptions were:

- Intake temperature, T_{in} = 21°C
- 3 compression stages to raise the pressure to 8 bar
- Polytropic extent = 1.4
- Recovery ratio of ASU = 70% by volume
- R_{air} = 0.287 kJ/kg.K

A 300 t/day ammonia plant will require 0.82 t/t NH_3 of nitrogen. Thus, the air intake ($\dot{m}$) into the first compressor of the ASU will be 1.8 t/t NH_3. The fluid power required was calculated to be 0.792 MW. The total combined shaft and driver work is given by Equation A.8.

$$\dot{W}_{total} = \frac{\dot{W}_{fluid}}{\eta_i \eta_{driver}} \qquad (\text{Equation A.8})$$

Assuming an adiabatic compressor efficiency (η_i) of 75% and a driver efficiency (η_{driver}) of 95%, the total power required ($\dot{W}_{total}$) was found to be 1.112 MW or 0.09 MWh/t NH_3. 10.5 kg/s (3 t/t NH_3) of water was required for interstage cooling, but the literature assumed the cooling water pump power was assumed to be negligible in this circumstance. The amount of makeup water required for the ASU was 0.2 kg/s (0.06 t/t NH_3)

A.43. Ammonia synthesis unit power calculation

Morgan (2013) calculated the power requirements and cooling duty of an ammonia synthesis loop for a 300 t/day capacity ammonia plant. The power in the synthesis loop was required only for the compression train and recycle compressor. Assuming operation at 150 bar and 450°C, a total 7.91 MW of electrical power was required by the compressors.

The cooling water requirements were based on the duties of the heat exchangers that preheated the gases entering the reactor and cooled down the product streams leaving the reactor, as well as the intercoolers that cooled the gas between compression stages to minimise compressor work. The ammonia synthesis loop required a cooling duty of 6.7 MW. The cooling water flowrate was calculated using Equation A.9.

$$\dot{Q} = \dot{m}_{H_2O} CP_{H_2O} \Delta T \qquad \text{(Equation A.9)}$$

The assumptions were:

- Specific heat capacity of water, CP_{H_2O} = 4.18 kJ/kg.K
- Cooling water range = 5 - 15°C

The mass flowrate of water ($\dot{m}_{H_2O}$) was calculated to be 145.7 kg/s or 41.53 t/t NH_3 based on a cooling water range of 11°C. The cooling water pump was sized using Equation A.10.

$$P_{Pump} = \frac{1.67 \dot{m}_{H_2O} \Delta P}{\eta_{Pump}} \qquad \text{(Equation A.10)}$$

where $\dot{m}_{H_2O}$ is the mass flow rate of water in m^3/min; ΔP is the pressure drop in the piping in *bar*, and η_{Pump} is the efficiency of the pump.

Assuming the reciprocating pump has:

- Pressure drop, ΔP = 6 *bar*
- Pump efficiency, η_{Pump} = 85%

The total pumping power was found to be 0.103 MW, which was almost negligible with respect to the whole plant. This brought the total power required in the ammonia synthesis loop to be 8.01 MW or 0.64 MWh/t NH_3.

Assuming a closed cycle cooling water system, based on the cooling duty of 6.7 MW, the makeup water required to replace evaporation, drift and blowdown losses was calculated to be 2.8 kg/s (0.806 t/t NH_3).

A.44. Capital cost of steam reforming ammonia plant

➢ Adjustment for hydrogen plant, ASU and ammonia synthesis:

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad (\text{Equation 4.5})$$

Assuming:

- Capacity exponent: b = 0.732 for hydrogen plant, b = 0.7 for ASU and ammonia synthesis
- Plant cost index: F_r (2005) = 292, F_r (2010) = 349, F_p (2012) = 370 (Appendix A.2)
- US$ to A$ conversion rate: L (2005) = 1.33, L (2010) = 1.14 (Appendix A.3)

Table A.87: Capital cost adjustment for ammonia plant components (Cost are expressed in 2012A$)

	Original				Adjusted			
	Capacity	Cost year	Currency	Original cost	Capacity	Cost year	Currency	Adjusted cost
Hydrogen plant	379 t/day	2005	US$	$ 135 million [a]	360 t/day	2012	A$	$ 219 million
ASU	250 t/day	2010	US$	$ 6.90 million	1650 t/day	2012	A$	$ 31.2 million
Ammonia synthesis plant	300 t/day	2010	US$	$ 22.5 million	2000 t/day	2012	A$	$ 103 million
Total						2012	A$	$ 353 million

[a] Capital cost obtained from Section 4.5.2.2.2.

A.45. Capital cost of coal to ammonia plant

- Adjustment for hydrogen plant, ASU and ammonia synthesis:

$$I_p = I_r\left(\frac{Q_p}{Q_r}\right)^b\left(\frac{F_p}{F_r}\right)L \qquad \text{(Equation 4.5)}$$

Assuming:

- Capacity exponent: b = 0.733 for hydrogen plant, b = 0.7 for ASU and ammonia synthesis
- Plant cost index: F_r (2005) = 292, F_r (2010) = 349, F_p (2012) = 370 (Appendix A.2)
- US$ to A$ conversion rate: L (2005) = 1.33, L (2010) = 1.14 (Appendix A.3)

Table A.88: Capital cost adjustment for ammonia plant components (Cost are expressed in 2012A$)

	Original				Adjusted			
	Capacity	Cost year	Currency	Original cost	Capacity	Cost year	Currency	Adjusted cost
Hydrogen plant	284 t/day	2005	US$	$ 291 million [a]	360 t/day	2012	A$	$ 583 million
Ammonia synthesis plant	300 t/day	2010	US$	$ 22.5 million	2000 t/day	2012	A$	$ 103 million
Total						2012	A$	$ 686 million

[a] Capital cost obtained from Section 4.5.2.3.2.

A.46. Ammonia substitution impact indicator calculations

Step 1: Categorise material flow data into environmental and economic impact categories

Table A.89: Environmental impacts for ammonia production from different fossil fuels

Option	Ammonia		
Feedstock	Natural gas	Black coal	CSG
Technology	LAC	CG	LAC
Environmental impact indicators	**t/t NH_3**	**t/t NH_3**	**t/t NH_3**
Global Warming Potential (GWP)	2.04E+00	4.61E+00	2.04E+00
Acidification Potential (ADP)	1.38E-04	8.22E-02	1.38E-04
Photochemical Oxidation Potential (POP)	4.18E-05	9.84E-05	4.18E-05
Particulate Matter Formation (PMF)	8.51E-05	2.92E-04	8.51E-05
Freshwater Withdrawal (FWW)	4.13E+00	1.11E+01	7.58E+00
Saline Water Discharge (SWD)	6.54E-01	9.69E-01	6.99E-01
Solid Waste Generation (SWG)	4.48E-02	1.67E+00	4.48E-02
Economic impact indicators	**2012A$/t NH_3**	**2012A$/t NH_3**	**2012A$/t NH_3**
Annualised captial costs	75.5	146.6	75.5
Cash operating costs	180.3	215.6	144.6
Total operating costs	**255.8**	**362.2**	**220.1**

Step 2: Calculate the environmental and economic impacts resulting from substitution of natural gas

Table A.90: Environmental impacts due to substitution of natural gas in ammonia production in Australia

Option	Ammonia	
Feedstock	NG→BlC	NG→CSG
Technology	LAC→CG	LAC
Environmental impact indicators	**t/t NH_3**	**t/t NH_3**
Global Warming Potential (GWP)	2.57E+00	0.00E+00
Acidification Potential (ADP)	8.21E-02	0.00E+00
Photochemical Oxidation Potential (POP)	5.65E-05	0.00E+00
Particulate Matter Formation (PMF)	2.07E-04	0.00E+00
Freshwater Withdrawal (FWW)	3.47E+00	0.00E+00
Saline Water Discharge (SWD)	2.70E-01	0.00E+00
Solid Waste Generation (SWG)	1.63E+00	0.00E+00
Economic impact indicators	**2012A$/t NH_3**	**2012A$/t NH_3**
Annualised captial costs	146.6	0.0
Cash operating costs	35.2	-35.8
Total operating costs	**181.8**	**-35.8**

Step 3: Calculate annual environmental impacts

Annual Australian ammonia production, y_{NH_3} = 1.7 x 10^6 tonnes (WYLD Group et al. 2008)

Table A.91: Annual environmental impacts due to substitution of natural gas in Australia's ammonia production

Option	Ammonia	
Feedstock	NG→BlC	NG→CSG
Technology	LAC→CG	LAC
Environmental impact indicators	**t/yr**	**t/yr**
Global Warming Potential (GWP)	4.36E+06	0.00E+00
Acidification Potential (ADP)	1.39E+05	0.00E+00
Photochemical Oxidation Potential (POP)	9.61E+01	0.00E+00
Particulate Matter Formation (PMF)	3.52E+02	0.00E+00
Freshwater Withdrawal (FWW)	5.90E+06	0.00E+00
Saline Water Discharge (SWD)	4.59E+05	0.00E+00
Solid Waste Generation (SWG)	2.76E+06	0.00E+00
Economic impact indicators	**2012A$mil/yr**	**2012A$mil/yr**
Annualised captial costs	204.4	0.0
Cash operating costs	59.6	-60.8
Total operating costs	**263.9**	**-60.8**

Step 4: Divide by natural gas substituted

Natural gas substituted in ammonia production = 5.1 x 10^5 tonnes

Table A.92: Substitution impact indicators for ammonia production in Australia

Option	Ammonia			
Feedstock	NG→BlC		NG→CSG	
Technology	Extraction and refining	LAC→CG	Extraction and refining	LAC
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**
Global Warming Potential (GWP)	-1.08E-01	4.42E+00	-6.23E-02	0.00E+00
Acidification Potential (ADP)	-6.01E-04	1.41E-01	-6.08E-04	0.00E+00
Photochemical Oxidation Potential (POP)	-2.65E-04	9.74E-05	-4.34E-04	0.00E+00
Particulate Matter Formation (PMF)	-3.65E-05	3.57E-04	-7.71E-05	0.00E+00
Freshwater Withdrawal (FWW)	4.36E-02	5.98E+00	-2.88E-01	0.00E+00
Associated Water Withdrawal (AWW)	-2.83E-01	0.00E+00	4.51E+00	0.00E+00
Saline Water Discharge (SWD)	-2.02E-02	4.65E-01	-4.51E-02	0.00E+00
Solid Waste Generation (SWG)	1.06E+01	2.80E+00	4.30E-02	0.00E+00
Economic impact indicators	**2012A$/t NG substituted**		**2012A$/t NG substituted**	
Annualised captial costs	252.7		-	
Cash operating costs	60.7		-61.6	
Total operating costs	**313.4**		**-61.6**	

Step 5: Normalisation of environmental impacts

Table A.93: Normalised substitution impact indicators for ammonia production in Australia

Option	Ammonia	
Feedstock	NG→BlC	NG→CSG
Technology	LAC→CG	LAC
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	7.90E-09	-1.14E-10
Acidification Potential (ADP)	8.23E-08	-3.55E-10
Photochemical Oxidation Potential (POP)	-1.52E-09	-3.93E-09
Particulate Matter Formation (PMF)	3.86E-10	-9.29E-11
Freshwater Withdrawal (FWW)	7.32E-11	-3.50E-12
Associated Water Withdrawal (AWW)	-9.04E-10	1.44E-08
Saline Water Discharge (SWD)	7.08E-12	-7.17E-13
Solid Waste Generation (SWG)	2.16E-07	6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised captial costs	252.7	-
Cash operating costs	60.7	-61.6
Total operating costs	**313.4**	**-61.6**

A.47. Alumina plant utility system requirements calculations

- Alumina production rate = 480 t alumina/hr
- Calcination energy requirement = 3.1 GJ/t alumina (Hudson et al. 2000)

Calculating electricity required by alumina refinery

- Refinery eletrictiy requirement = 2806 MJ/t alumina (Griffing & Overcash 2010)
  = 2806/3600
  = 0.78 MWh/t alumina

Calculating steam required by alumina refinery

Assume alumina refinery requires steam for digestion use.

- Steam enthalpy = 1320 MJ/t @ 100 bar, 311°C
- Alumina production rate = 480 t alumina/hr
- Digestion heat requirement = 4200 MJ/t alumina (Griffing & Overcash 2010)
  = 4200(480)
  = 202000 MJ/hr
- Refinery steam requirement = 202000/1320
  = 1530 t steam/hr
  = 1530/480
  = 3.18 t steam/t alumina

A.48. Natural gas-based alumina plant calciner HYSYS model

Assumptions

- Air to NG ratio = 11
- Hot flue gas + evaporated free water = 1100°C
- Natural gas feed rate = 34 t/hr
- HRSG efficiency = 85%

Results of modelling

- Steam production rate = 668 t/hr (100% efficiency)
  = (668)(0.85)/34
  = 16.8 t steam/t NG (85% efficiency)

Table A.94: Mass balance for alumina refinery natural gas-fired calciner HYSYS model

Stream number	Natural gas feed	Ambient air feed	Flue1	Bottom	Alumina free water	Flue2	Flue3	BFW	Steam
Vapour fraction	1.00	1.00	1.00	0	0	1.00	1.00	0	1
Temperature (°C)	15.0	25.0	1870	1870	39.6	1100	1210	310	311
Pressure (kPa)	1000	1000	1000	1000	101	101	397	10000	10000
Molar flow (kmol/hr)	1910	21000	23000	0	8350	31300	97300	89600	89600
Mass flow (t/hr)	34.0	606	640	0	150	790	2710	1610	1610
Components (mol%)									
CH4	0.91	0	0	0	0	0	0	0	0
C2H6	0.05	0	0	0	0	0	0	0	0
C3H8	0.01	0	0	0	0	0	0	0	0
i-C4H10	0	0	0	0	0	0	0	0	0
n-C4H10	0	0	0	0	0	0	0	0	0
i-C5H12	0	0	0	0	0	0	0	0	0
n-C5H12	0	0	0	0	0	0	0	0	0
n-C6H14	0	0	0	0	0	0	0	0	0
N2	0.01	0.79	0.72	0	0	0.53	0.72	0	0
O2	0	0.21	0	0	0	0.02	0	0	0
CO2	0.02	0	0.09	0	0	0.06	0.09	0	0
H2O	0	0	0.17	0	1.00	0.39	0.17	1.00	1.00
He	0	0	0	0	0	0	0	0	0
H2	0	0	0	0	0	0	0	0	0
CO	0	0	0	0	0	0	0	0	0
Ar	0	0	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0	0	0	0
NH3	0	0	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	0	1.00	1.00	1.00	1.00	1.00

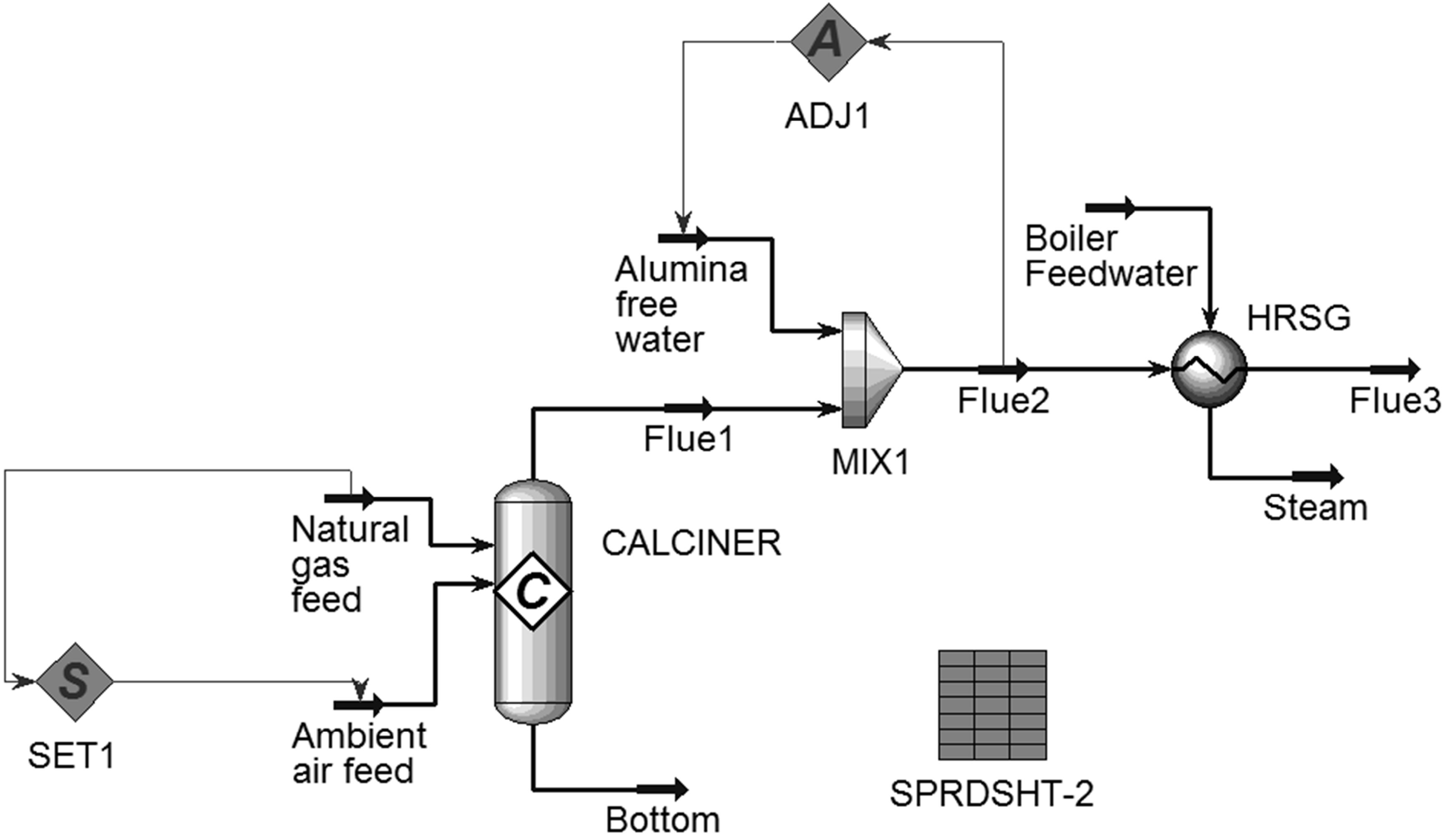

Figure A.8: Alumina plant natural gas-fired calciner HYSYS model

A.49. Natural gas-based alumina plant cogeneration unit HYSYS model

The cogeneration system consists of a gas turbine and a Heat Recovery Steam Generator (HRSG).

Assumptions

- Mass of NG = 144 t/hr
- HHV of NG = 50.9 GJ/t (calculated by HYSYS)
- Gas turbine efficiency = 32.8% HHV
- Gross output = (0.328)(50.9 GJ/t)/[(3.6GJ/MWh)(144t/hr)]
  = 668.7 MW
  = 4.68 MWh/t NG
- Turbine inlet max temperature = 1370°C (Bedilion et al. 2009)
- Air to NG ratio = 30
- Steam properties = 311°C @ 10,000 kPa
- Steam generation efficiency = 85%

Results of modelling

- Turbine inlet temperature = 1350°C
- HRSG inlet = 561°C
- Steam generated = 1449 t/hr (100% efficiency)
  = 1449(0.85)/144
  = 8.55 t steam/t NG (85% efficiency)

Table A.95: Mass balance for alumina refinery natural gas-fired cogeneration HYSYS model

Stream number	Ambient air feed	Compressed air	Natural gas feed	Fuel mix	Flue1	Bottom	Flue2	Flue3	Flue4	BFW	Steam
Vapour fraction	1.00	1.00	1.00	1.00	1.00	0	1.00	1.00	1.00	0	1
Temperature (°C)	25.0	635	15.0	602	1350	1350	1100	561	320	310	311
Pressure (kPa)	101	3100	3100	3100	3100	3100	1070	51.7	17.2	10000	10000
Molar flow (kmol/hr)	243000	243000	8080	251000	251000	0	251000	251000	251000	80400	80400
Mass flow (t/hr)	7000	7000	144	7140	7140	0	7140	7140	7140	1450	1450
Components (mol%)											
CH4	0	0	0.91	0.03	0	0	0	0	0	0	0
C2H6	0	0	0.05	0	0	0	0	0	0	0	0
C3H8	0	0	0.01	0	0	0	0	0	0	0	0
i-C4H10	0	0	0	0	0	0	0	0	0	0	0
n-C4H10	0	0	0	0	0	0	0	0	0	0	0
i-C5H12	0	0	0	0	0	0	0	0	0	0	0
n-C5H12	0	0	0	0	0	0	0	0	0	0	0
n-C6H14	0	0	0	0	0	0	0	0	0	0	0
N2	0.79	0.79	0.01	0.76	0.76	0	0.76	0.76	0.76	0	0
O2	0.21	0.21	0	0.20	0.14	0	0.14	0.14	0.14	0	0
CO2	0	0	0.02	0	0.03	0	0.03	0.03	0.03	0	0
H2O	0	0	0	0	0.06	0	0.06	0.06	0.06	1.00	1.00
He	0	0	0	0	0	0	0	0	0	0	0
H2	0	0	0	0	0	0	0	0	0	0	0
CO	0	0	0	0	0	0	0	0	0	0	0
Ar	0	0	0	0	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0	0	0	0	0	0
NH3	0	0	0	0	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	1.00	1.00	0.00	1.00	1.00	1.00	1.00	1.00

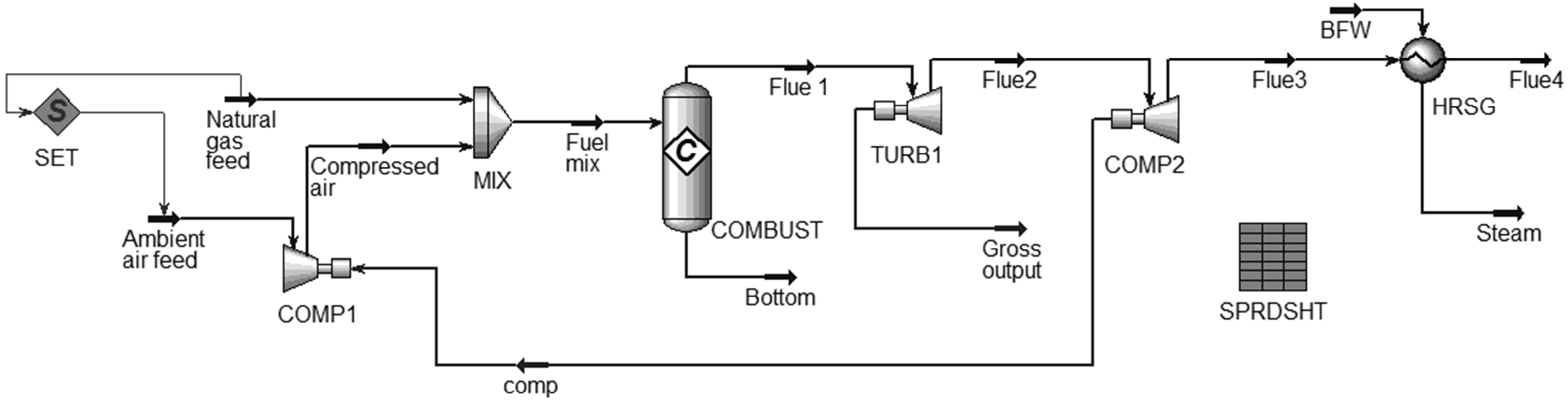

Figure A.9: Alumina plant natural gas-fired cogeneration HYSYS model

A.50. Natural gas-based alumina refinery utility system calculations

First, the steam recovered from calciner hot flue gas is calculated, and then the remaining steam recovered using gas turbine hot flue gas is calculated.

Alumina production rate = 480 t/hr

Calculating steam recovered from calcination
Assume calciner converts natural gas fuel to energy at 85% efficiency.

Calcination energy required = 3.1 GJ/t alumina

Natural gas required = 3.1/[(51.34)(0.85)]
= 0.071 t NG fuel/t alumina

Steam recovered from calciner = 16.8 t steam/t NG fuel (see Appendix A.48)
= (16.8)(0.071)
= 1.20 t steam/t alumina

Calculating steam recovered from cogeneration
Steam required by alumina refinery = 3.18 t steam/t alumina (see Appendix A.47)

Steam recovered from gas turbine HRSG = 3.18 - 1.20
= 1.99 t steam/t alumina

Steam generated = 8.55 t steam/t NG fuel (see Appendix A.49)

Natural gas required = 1.99/8.55
= 0.23 t NG fuel/t alumina

Calculating export electricity
Electricity generated = 4.68 MWh/t NG fuel (see Appendix A.48)
= (4.68)(0.23)
= 1.09 MWh/t alumina
= 522 MW

Utility requirement = 522(21.1)/(471)
= 23 MW
= 0.05 MWh/t alumina

Refinery electricity requirement = 0.78 MWh/t alumina (see Appendix A.47)
= 374 MW

Export electricity = 1.09 - 0.05 - 0.78
= 0.26 MWh/t alumina
= 125 MW

Total natural gas required = 0.071+0.23
= 0.303 t NG fuel/t alumina

A.51. Natural gas-based alumina refinery utility system capital cost calculations

(A) The capital costs of equipment were based on CCGT technology costs reported in Bedilion et al. (2009).
(B) The steam turbine and cooling water system is removed.
(C) The gross output of the gas turbine is adjusted based on capacity only using Equation 4.5 until it matches the gross output of the gas turbine from Appendix A.50.
(D) The capital cost of the calciner HRSG is added to the total capital costs.
(E) The capital costs are adjusted for inflation from 2009 to 2012 Australian dollars using Equation 4.5.

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad \text{(Equation 4.5)}$$

Assuming:

- Q is based on gross output of gas turbine in MW
- Capacity exponent: b = 0.76 for cogeneration plant
- Plant cost index: F_r (2009) = 337, F_p (2012) = 370
- No conversion rate L

Table A.96: Adjustment for capital cost of natural-gas based alumina refinery utility system

Parameters	A	B	C	D	E
Gas turbine output (MW)	472	472	522		
Steam turbine output (MW)	261	0	0		
Auxiliaries (MW)	21.1	21.1	23.3		
Net output (MW)	711	451	498		
Fuel consumption(GJ-HHV/hr)	5,171	5,171	5,717	1,525	
Efficiency (%)	49.5	31.4	31.4		
Capital cost	2009A$	2009A$	2009A$	2009A$	2012A$
Feedwater & misc. BOP systems	28.3	28.3	30.5		33.54
Combustion turbine & accessories	190.0	190.0	204.8		225.20
HRSG, ducting and stack	96.5	96.5	104.2	62.4	114.56
Steam turbine generator (inc. ACC)	195.0	0	0.0		0.00
Cooling water system	6.7	0	0.0		0.00
Accessory electric plant	66.0	66.0	71.3		78.37
Instrumentation & controls	24.7	24.7	26.6		29.27
Improvements to site	22.1	22.1	23.9		26.28
Buildings & structures	23.4	23.4	25.2		27.76
Total bare erected cost	653.0	653.0	486.5		534.98

A.52. Black coal-based alumina refinery utility system HYSYS model

Assumptions

- Efficiency of IGCC = 45%

Values taken from IGCC mass balance

- Mass of Australian black coal = 212 t/hr (see Appendix A.37)
- Mass of syngas = 368 t/hr (see Appendix A.37)
- Ratio of syngas to black coal = 368/212
  = 1.74 t syngas/t coal
- Gas turbine output = 446 MW
  = 446/368
  = 1.21 MWh/t syngas

Results of modelling

- Syngas Higher Heating Value (HHV) = 10.9 GJ/t
- Steam generated = 632 t/hr (100% efficiency)
  = [(632)(0.85)]/368
  = 1.46 t steam/t syngas (85% efficiency)

Table A.97: Mass balance for alumina plant black coal-based utility system HYSYS model

Stream number	Ambient air feed	Compressed air	Syngas	Nitrogen	Fuel mix	Flue1	Bottom	Flue2	Flue3	BFW	Steam
Vapour fraction	1.00	1.00	1.00	1.00	1.00	1.00	0	1.00	1.00	0	1.00
Temperature (°C)	25.0	376	196	93	196	914	914	535	320	310	311
Pressure (kPa)	101	1000	3170	2650	1620	1000	1000	95.5	61.0	10000	10000
Molar flow (kmol/hr)	92700	92700	17500	17000	127000	120000	0	120000	120000	35100	35100
Mass flow (t/hr)	2680	2680	368	476	3520	3520	0	3520	3520	632	632
Components (mol%)											
CH_4	0	0	0	0	0	0.01	0	0	0	0	0
C_2H_6	0	0	0	0	0	0	0	0	0	0	0
C_3H_8	0	0	0	0	0	0	0	0	0	0	0
$i\text{-}C_4H_{10}$	0	0	0	0	0	0	0	0	0	0	0
$n\text{-}C_4H_{10}$	0	0	0	0	0	0	0	0	0	0	0
$i\text{-}C_5H_{12}$	0	0	0	0	0	0	0	0	0	0	0
$n\text{-}C_5H_{12}$	0	0	0	0	0	0	0	0	0	0	0
$n\text{-}C_6H_{14}$	0	0	0	0	0	0	0	0	0	0	0
N_2	0.79	0.79	0.01	0.99	0.71	0.75	0	0.75	0.75	0	0
O_2	0.21	0.21	0	0.01	0.15	0.13	0	0.13	0.13	0	0
CO_2	0	0	0.17	0	0.02	0.08	0	0.08	0.08	0	0
H_2O	0	0	0	0	0	0.03	0	0.03	0.03	1.00	1.00
He	0	0	0.01	0	0	0	0	0	0	0	0
H_2	0	0	0.36	0	0.05	0	0	0	0	0	0
CO	0	0	0.45	0	0.06	0	0	0	0	0	0
Ar	0	0	0	0	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0	0	0	0	0
H_2S	0	0	0	0	0	0	0	0	0	0	0
NH_3	0	0	0	0	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	1.00	1.00	1.00	0.00	1.00	1.00	1.00	1.00

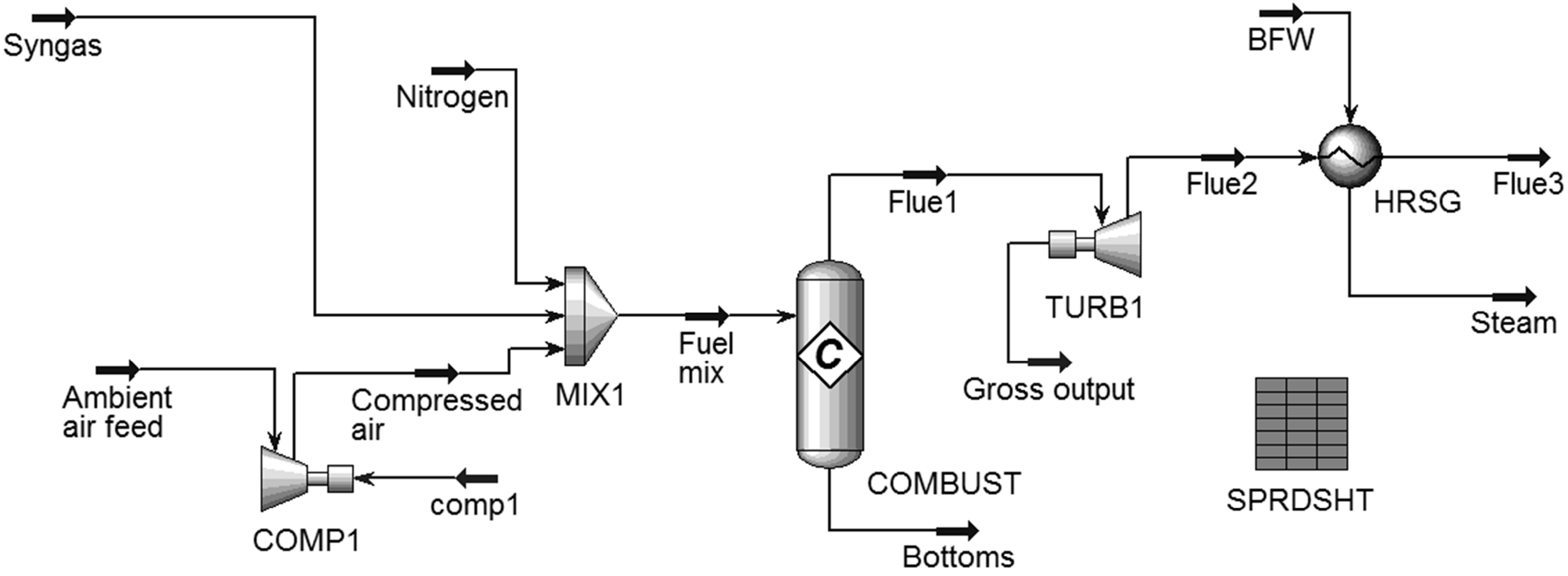

Figure A.10: Alumina plant black coal-based utility system HYSYS model.

A.53. Black coal-based alumina plant syngas-fired calciner model

Assumptions

- Air to NG ratio = 11
- Mass of free water in alumina absorbed into hot flue gas, which lowers temperature of hot flue gas to 1100°C
- Syngas feed rate = 210 t/hr
- HRSG efficiency = 85%

Results of modelling

- Steam production rate = 588 t/hr (100% efficiency)
  = (588)(0.85)/210
  = 2.38 t steam/t syngas (85% efficiency)

Table A.98: Mass balance for alumina plant syngas-fired calciner system

Stream number	Syngas feed	Ambient air feed	Flue1	Bottom	Alumina free water	Flue2	Flue3	BFW	Steam
Vapour fraction	1.00	1.00	1.00	0	0	1.00	1.00	0	1.00
Temperature (°C)	15.0	25.0	1920	1920	39.6	1100	320	310	311
Pressure (kPa)	1000	1000	1000	1000	101	101	1.32	10000	10000
Molar flow (kmol/hr)	9970	10600	16500	0	8070	31300	24600	32600	32600
Mass flow (t/hr)	210	305	515	0	145	790	660	588	588
Components (mol%)									
CH4	0	0	0.06	0	0	0.04	0.04	0	0
C2H6	0	0	0	0	0	0	0	0	0
C3H8	0	0	0	0	0	0	0	0	0
i-C4H10	0	0	0	0	0	0	0	0	0
n-C4H10	0	0	0	0	0	0	0	0	0
i-C5H12	0	0	0	0	0	0	0	0	0
n-C5H12	0	0	0	0	0	0	0	0	0
n-C6H14	0	0	0	0	0	0	0	0	0
N2	0.01	0.79	0.51	0	0	0.34	0.34	0	0
O2	0	0.21	0	0	0	0	0	0	0
CO2	0.17	0	0.32	0	0	0.21	0.21	0	0
H2O	0	0	0.11	0	1.00	0.40	0.40	1.00	1.00
He	0.01	0	0.01	0	0	0	0	0	0
H2	0.36	0	0	0	0	0	0	0	0
CO	0.45	0	0	0	0	0	0	0	0
Ar	0	0	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0	0	0	0
NH3	0	0	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	0	1.00	1.00	1.00	1.00	1.00

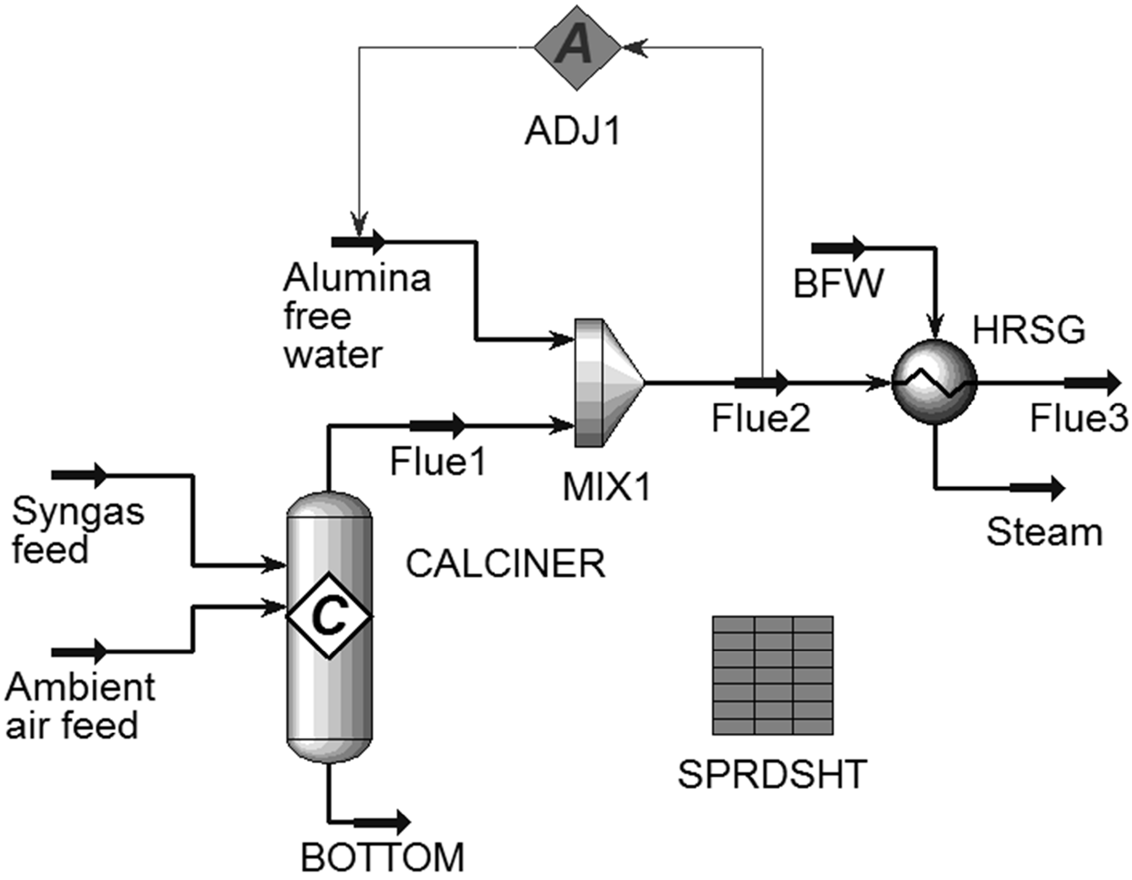

Figure A.11: Alumina plant syngas-fired calciner system

A.54. Black coal-based alumina refinery utility system calculations

First, the steam recovered from calciner hot flue gas is calculated, and then the remaining steam recovered using gas turbine hot flue gas is calculated.

Alumina production rate = 480 t/hr

Calculating steam recovered from calcination

- Assume calciner converts syngas fuel to energy at 85% efficiency.
- Calcination energy required = 3.1 GJ/t alumina
- Syngas Higher Heating Value (HHV) = 10.9 GJ/t (see Appendix A.52)
- Syngas required = 3.1/[(10.9)(0.85)]
  = 0.334 t syngas fuel/t alumina
- Steam recovered from calciner = 2.38 t steam/t syngas fuel
  (see Appendix A.53)
  = (2.38)(0.334)
  = 0.795 t steam/t alumina

Calculating steam recovered from cogeneration

- Steam required by alumina refinery = 3.18 t steam/t alumina (see Appendix A.47)
- Steam recovered from gas turbine HRSG = 3.18-0.795 = 2.39 t steam/t alumina
- Steam generated = 1.97 t steam/t syngas fuel
  (see Appendix A.52)
- Syngas required = 2.39/1.97
  = 1.21 t syngas fuel/t alumina

Calculating export electricity

- Electricity generated = 1.21 MWh/t syngas fuel
  (see Appendix A.52)
  = (1.21)(1.21) = 1.47 MWh/t alumina
  = 704 MW

For this design, the auxiliaries were assumed to be the same as the IGCC case in Appendix A.28, but the Claus plant and steam turbine components with their associated auxiliaries are excluded.

- Auxiliairies = [(125750-100-250-2090)/1000](446)/(704)
  = 191 MW
  = 0.40 MWh/t alumina
- Refinery electricity requirement = 0.78 MWh/t alumina (see Appendix A.47)
  = 374 MW
- Export electricity = 1.47-0.40-0.78
  = 0.29 MWh/t alumina
  = 139 MW

Total black coal required = (1.21+0.33)/(1.74)
= 0.89 t black coal/t alumina

A.55. Black coal-based alumina refinery utility system capital cost calculations

(A) The capital costs of equipment were based on IGCC technology costs reported in Bedilion et al. (2009).
(B) The steam turbine and cooling water system is removed.
(C) The gross output of the gas turbine is adjusted based on capacity only using Equation 4.5 until it matches the gross output of the gas turbine from Appendix A.54.
(D) The capital cost of the calciner HRSG is added to the total capital costs. Due to the additional syngas and subsequent black coal feedstock required, the gasifier is increased in size and all capital costs are adjusted based on fuel consumption using Equation 4.5.
(E) The capital costs are adjusted for inflation from 2009 to 2012 Australian dollars using Equation 4.5.

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad \text{(Equation 4.5)}$$

Assuming:

- Q is based on gross output of gas turbine in MW or black coal consumption in GJ-HHV/hr
- Capacity exponent: b = 0.7
- Plant cost index: F_r (2009) = 337, F_p (2012) = 370
- No conversion rate L

Table A.99: Adjustment for capital cost of black coal-based alumina refinery utility system

Parameters	A	B	C	D	E
Gas turbine output (MW)	572	572	704		
Steam turbine output (MW)	318	0	0		
Auxiliaries (MW)	156	156	191		
Net output (MW)	728	416	513		
Fuel consumption(GJ-HHV/hr)	6,659	6,659	8,159	10,400	
Efficiency (%)	39.4	22.5	22.6		
Capital cost	2009A$	2009A$	2009A$	2009A$	2012A$
Coal and fluxant/sorbent handling	84.8	84.8	97.7	112.6	123.9
Coal and fluxant/sorbent prep & feed	353.6	353.6	407.6	469.9	516.8
Feedwater & misc. BOP systems	38.6	38.6	44.6	51.4	56.5
Gasifier (inc. ASU) & accessories	1,123.4	1,123.4	1295.1	1493.0	1642.0
Gas cleanup & piping/flue gas cleanup	161.5	161.5	186.2	214.6	236.0
Combustion turbine & accessories	189.7	189.7	222.2	222.2	244.3
HRSG, ducting and stack	96.5	96.5	113.0	171.1	188.2
Steam turbine generator (inc. ACC)	227.3	0	0.0	0.0	0.0
Cooling water system	41.5	0	0.0	0.0	0.0
Ash/spent sorbent handling	109.3	109.3	126.0	145.3	159.8
Accessory electric plant	130.3	130.3	150.2	173.1	190.4
Instrumentation & controls	38.8	38.8	44.7	51.5	56.7
Improvements to site	38.6	38.6	44.5	51.3	56.4
Buildings & structures	38.4	38.4	44.3	51.1	56.2
Total bare erected cost	2,672.3	2,403.5	2776.0	3207.0	3527.0

A.56. Alumina refinery utility system substitution impact indicator calculations

Step 1: Categorise material flow data into environmental impact categories

Table A.100: Environmental impact indicators for utilities in alumina refineries based on different fossil fuels

Option	Alumina refinery utility system		
Feedstock	NG	BlC	CSG
Technology	Cogen	IGCC	Cogen
Environmental impact indicators	**t/t alumina**	**t/t alumina**	**t/t alumina**
Global Warming Potential (GWP)	6.83E-01	1.63E+00	6.83E-01
Acidification Potential (ADP)	6.40E-04	8.25E-05	6.40E-04
Photochemical Oxidation Potential (POP)	3.68E-05	1.69E-06	3.68E-05
Particulate Matter Formation (PMF)	2.32E-05	4.13E-05	2.32E-05
Freshwater Withdrawal (FWW)	-2.32E-01	-4.22E-01	-2.32E-01
Saline Water Discharge (SWD)	9.82E-02	7.19E-02	9.82E-02
Solid Waste Generation (SWG)	-1.40E-02	1.52E-01	-1.40E-02
Economic impact indicators	**2012A$/t alumina**	**2012A$/t alumina**	**2012A$/t alumina**
Annualised captial costs	19.9	131.0	19.9
Cash operating costs	48.2	66.1	35.3
Total operating costs	**68.1**	**197.1**	**55.1**

Step 2: Calculate the environmental and economic impacts resulting from substitution of natural gas

Table A.101: Environmental impacts due to substitution of natural gas in alumina refineries

Option	Alumina refinery utility system	
Feedstock	NG→BlC	NG→CSG
Technology	Cogen→IGCC	Cogen
Environmental impact indicators	**t/t alumina**	**t/t alumina**
Global Warming Potential (GWP)	9.50E-01	0.00E+00
Acidification Potential (ADP)	-5.57E-04	0.00E+00
Photochemical Oxidation Potential (POP)	-3.51E-05	0.00E+00
Particulate Matter Formation (PMF)	1.81E-05	0.00E+00
Freshwater Withdrawal (FWW)	-1.90E-01	0.00E+00
Saline Water Discharge (SWD)	-2.62E-02	0.00E+00
Solid Waste Generation (SWG)	1.66E-01	0.00E+00
Economic impact indicators	**2012A$/t alumina**	**2012A$/t alumina**
Annualised captial costs	131.0	0.0
Cash operating costs	17.9	-12.9
Total operating costs	**148.9**	**-12.9**

Step 3: Calculate annual environmental impacts

Annual Australian ammonia production = 9,300,000 t/yr

Table A.102: Annual environmental impacts due to substitution of natural gas in Australia's alumina refineries

Option	Alumina refinery utility system	
Feedstock	NG→BlC	NG→CSG
Technology	Cogen→IGCC	Cogen
Environmental impact indicators	**t/yr**	**t/yr**
Global Warming Potential (GWP)	5.39E+06	0
Acidification Potential (ADP)	-3.16E+03	0
Photochemical Oxidation Potential (POP)	-1.99E+02	0
Particulate Matter Formation (PMF)	1.02E+02	0
Freshwater Withdrawal (FWW)	-1.08E+06	0
Saline Water Discharge (SWD)	-1.49E+05	0
Solid Waste Generation (SWG)	9.41E+05	0
Economic impact indicators	**2012A$mil/yr**	**2012A$mil/yr**
Annualised captial costs	742.6	0.0
Cash operating costs	101.6	-73.2
Total operating costs	**844.2**	**-73.2**

Step 4: Divide by natural gas substituted

Natural gas substituted in ammonia production = 51,000 tonnes

Table A.103: Substitution impact indicators for alumina refineries in Australia

Option	Alumina refinery utility system			
Feedstock	NG→BlC		NG→CSG	
Technology	Extraction and refining	Cogen→IGCC	Extraction and refining	Cogen→IGCC
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**
Global Warming Potential (GWP)	-1.08E-01	3.18E+00	-6.23E-02	0.00E+00
Acidification Potential (ADP)	-6.01E-04	-1.86E-03	-6.08E-04	0.00E+00
Photochemical Oxidation Potential (POP)	-2.65E-04	-1.18E-04	-4.34E-04	0.00E+00
Particulate Matter Formation (PMF)	-3.65E-05	6.04E-05	-7.71E-05	0.00E+00
Freshwater Withdrawal (FWW)	4.36E-02	-6.36E-01	-2.88E-01	0.00E+00
Associated Water Withdrawal (AWW)	-2.83E-01	0.00E+00	4.51E+00	0.00E+00
Saline Water Discharge (SWD)	-2.02E-02	-8.78E-02	-4.51E-02	0.00E+00
Solid Waste Generation (SWG)	1.06E+01	5.55E-01	4.30E-02	0.00E+00
Economic impact indicators	**2012A$/t NG substituted**		**2012A$/t NG substituted**	
Annualised captial costs	438.0		-	
Cash operating costs	59.9		-43.2	
Total operating costs	**497.9**		**-43.2**	

Step 5: Normalisation of environmental impacts

Table A.104: Normalised substitution impact indicators for alumina refineries in Australia

Option	Alumina refinery utility system	
Feedstock	NG→BlC	NG→CSG
Technology	Cogen→IGCC	Cogen→IGCC
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	5.62E-09	-1.14E-10
Acidification Potential (ADP)	-1.44E-09	-3.55E-10
Photochemical Oxidation Potential (POP)	-3.46E-09	-3.93E-09
Particulate Matter Formation (PMF)	2.88E-11	-9.29E-11
Freshwater Withdrawal (FWW)	-7.20E-12	-3.50E-12
Associated Water Withdrawal (AWW)	-9.04E-10	1.44E-08
Saline Water Discharge (SWD)	-1.72E-12	-7.17E-13
Solid Waste Generation (SWG)	1.80E-07	6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised captial costs	438.0	-
Cash operating costs	59.9	-43.2
Total operating costs	**497.9**	**-43.2**

A.57. Nickel refinery utility system requirements calculations

Nickel production rate = 75,000 t nickel/yr (DEC 2011)
= 75,000/[(365)(24)]
= 8.56 t nickel/hr

Electricity requirement = 2.90 MWh/t nickel (Norgate & Rankin 2000)

H_2S required = 1,600 t H_2S /yr
= 1,600/[(365)(24)]
= 0.183 t H_2S /hr
= 0.021 t H_2S /t nickel

NH_3 required = 0.637 t NH_3 /t nickel (Norgate & Rankin 2000)

Calculating natural gas required using mass balances

(a) H_2S production

$$S(l)+H_2(g)\rightarrow H_2S(g) \qquad (\text{Equation 4.44})$$

Table A.105: Mass balance for H_2S fiormation

Component	S	H_2	H_2S
Molecular weight (kg/kmol)	32	2	34
Molar flow (mol)	-1	-1	+1
Mass flow (t)	0.941	0.0588	1

For 0.183t/hr of H_2S:

H_2 required = 0.0107 t H_2/hr
= 0.00125 t H_2/t nickel

S required = 0.172 t S/hr
= 0.0201 t S/t nickel

(b) NH_3 production

$$N_2+3H_2 \leftrightarrow 2NH_3 \qquad \Delta H^{\circ}_{298} = -92.44\, kJ/mol \qquad (\text{Equation 4.35})$$

Table A.106: Mass balance for NH_3 formation

Component	N_2	H_2	NH_3
Molecular weight (kg/kmol)	28	2	34
Molar flow (mol)	-1	-3	+2
Mass flow (t)	0.824	0.176	1

For 0.637t/hr of NH_3:

H_2 required = 0.962 t H_2/hr
= 0.112 t H_2/t nickel

N_2 required = 4.49 t N_2/hr

= 0.525 t N_2/t nickel

(c) H_2 production

H_2 required for H_2S and nickel refinery = 15 t H_2/day
= 0.625 t H_2/hr
= 0.0730 t/t nickel

H_2 required for NH_3 = 0.962 t H_2/hr

Total H_2 required = 1.59 t H_2/hr
= 0.185 t H_2/t nickel

(d) Natural gas required

Natural gas required for H_2 production = 2.89 + 0.317
= 3.21 t natural gas/t H_2
= 0.594 t natural gas/hr
= 0.0694 t natural gas/t nickel

Calculating steam and electricity generation

DEC (2011) reported natural gas consumption for steam production. It was assumed that this steam represents the steam requirement for the entire nickel refinery.

Natural gas consumed in boilers for steam use = 5.00 t natural gas/hr (DEC 2011)

Steam generation from natural gas boilers = 25.2 t steam/t natural gas (from HYSYS model in Figure A.12)

Steam requirement = 126 t steam/hr
= 14.7 t steam/t nickel

Table A.107: Mass balance for natural gas boiler HYSYS model

Stream number	Natural gas feed	Ambient air feed	Flue1	Bottoms	Flue2	BFW	Steam
Vapour fraction	1.00	1.00	1.00	0	1.00	0	1
Temperature (°C)	15.0	25.0	1870	1870	320	310	311
Pressure (kPa)	1000	1000	1000	1000	900	10000	10000
Molar flow (kmol/hr)	281	3090	3380	0	3380	8140	8140
Mass flow (t/hr)	5.00	89.1	94.1	0	94.1	147	147
Components (mol%)							
CH_4	0.91	0	0	0	0	0	0
C_2H_6	0.05	0	0	0	0	0	0
C_3H_8	0.01	0	0	0	0	0	0
i-C_4H_{10}	0	0	0	0	0	0	0
n-C_4H_{10}	0	0	0	0	0	0	0
i-C_5H_{12}	0	0	0	0	0	0	0
n-C_5H_{12}	0	0	0	0	0	0	0
n-C_6H_{14}	0	0	0	0	0	0	0
N_2	0.01	0.79	0.72	0	0.72	0	0
O_2	0.00	0.21	0.02	0	0.02	0	0
CO_2	0.02	0	0.09	0	0.09	0	0
H_2O	0	0	0.17	0	0.17	1.00	1.00
He	0	0	0	0	0	0	0
H_2	0	0	0	0	0	0	0
CO	0	0	0	0	0	0	0
Ar	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0
H_2S	0	0	0	0	0	0	0
NH_3	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	0	1.00	1.00	1.00

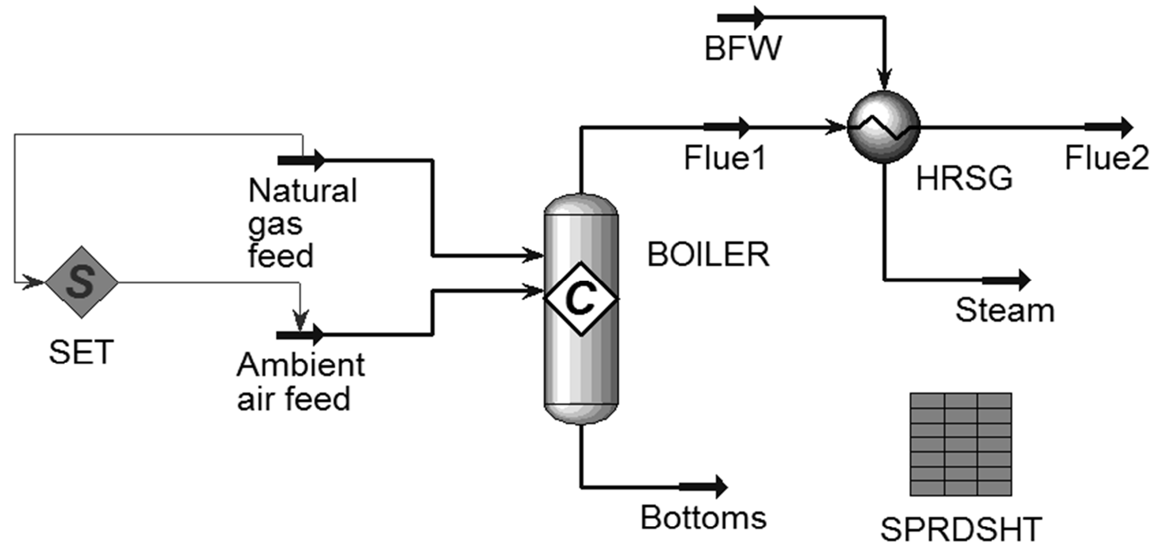

Figure A.12: HYSYS simulation of natural gas-fired boiler for steam generation calculations

A.58. Natural gas-based nickel refinery utility system calculations

Steam is produced from both the SMR plant and the gas turbine HRSG. As the SMR plant size is sized to meet the H_2 requirement, the steam production from the SMR plant is fixed. The remaining steam is then met by the gas turbine HRSG.

Steam produced from SMR plant = 4.18 t steam/t H_2 (Spath & Mann 2001)
= 6.64 t steam/hr
= 0.775 t steam/t nickel

Steam produced from gas turbine HRSG = 126 - 6.64 = 119 t steam/hr
= 14.7 - 0.775 = 13.9 t steam/t nickel

Natural gas consumption and electricity generated using the gas turbine is calculated using the HYSYS factors from Appendix A.49.

Natural gas required for gas turbine = 8.55 t steam/t natural gas (see Appendix A.49)
= 119/8.55 = 13.9 t natural gas/hr
= 13.9/8.55 = 1.63 t natural gas/nickel

Electricity generated from gas turbine = 4.68 MWh/t natural gas (see Appendix A.49)
= (4.68)(13.9) = 65.2 MW
= (4.68)(1.63) = 7.62 MWh/t nickel

The various auxiliaries and electricity internal usage is deducted from the gross electricity to calculate the net export electricity. The gas turbine/HRSG auxiliaries are calculated based on a ratio of auxiliaries (21.1 MW) over gross output (472 MW for both gas turbines) from Bedilion et al. (2009).

Refinery requirements = 24.8 MW = 2.90 MWh/t nickel

Gas turbine/HRSG auxiliaries = (65.2)(21.1)/(472)
= 2.91 MW = 0.340 MWh/t nickel

SMR H_2 plant = 0.903 MW = 0.105 MWh/t nickel

Air Separation Unit (ASU) = 0.49 MW = 0.0567 MWh/t nickel

NH_3 synthesis loop = 3.50 MW = 0.409 MWh/t nickel

Net export electricity = 65.2 - 24.8 – 2.9 - 0.903 - 0.49 - 3.5 = 32.6 MW
= 7.62 - 2.9 - 0.34 - 0.105 - 0.0567 - 0.409
= 3.81 MWh/t nickel

A.59. Natural gas-based nickel refinery utility system capital cost calculations

(A) The capital costs of equipment in CCGT technology were adapted from Bedilion et al. (2009).
(B) The steam turbine and cooling water system is removed.
(C) The gross output of the turbine is adjusted based on capacity only using Equation 4.5 until it matches the gross output of the gas turbine from Appendix A.58.
(D) The capital costs are adjusted for inflation from 2009 to 2012 Australian dollars using Equation 4.5.

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad \text{(Equation 4.5)}$$

Assuming:

- Q is based on gross output of gas turbine in MW
- Capacity exponent: b = 0.76 for cogeneration plant
- Plant cost index: F_r (2009) = 337, F_p (2012) = 370
- No conversion rate L

Table A.108: Adjustment for capital cost of cogeneration system for alumina refinery

Parameters	A	B	C	D
Gas turbine output (MW)	472	472	65.2	
Steam turbine output (MW)	261	0	0	
Auxiliaries (MW)	21.1	21.1	2.61	
Net output (MW)	711	451	0.304	
Fuel consumption(GJ-HHV/hr)	5171	5171	715	
Efficiency (%)	49.5	31.4	31.4	
Capital cost	2009A$	2009A$	2009A$	2012A$
Feedwater & misc. BOP systems	28.3	28.3	6.3	6.9
Combustion turbine & accessories	190.0	190.0	42.3	46.5
HRSG, ducting and stack	96.5	96.5	21.5	23.7
Steam turbine generator (inc. ACC)	195.0	0	0.0	0.0
Cooling water system	6.7	0	0.0	0.0
Accessory electric plant	66.0	66.0	14.7	16.2
Instrumentation & controls	24.7	24.7	5.5	6.0
Improvements to site	22.1	22.1	4.9	5.4
Buildings & structures	23.4	23.4	5.2	5.7
Total bare erected cost	653.0	653.0	100.5	110.5

A.60. Capital cost of chemical manufacture components in the natural gas-based nickel refinery utility system

- Adjustment for hydrogen plant, ASU and ammonia synthesis:

$$I_p = I_r \left(\frac{Q_p}{Q_r} \right)^b \left(\frac{F_p}{F_r} \right) L \qquad \text{(Equation 4.5)}$$

Assuming:

- Capacity exponent: b = 0.732 for hydrogen plant, b = 0.7 for ASU and ammonia synthesis
- CEPCI: F_r (2005) = 292, F_r (2010) = 349, F_p (2012) = 370
- US$ to A$ conversion rate: L (2005) = 1.33, L (2010) = 1.14

Table A.109: Capital cost adjustment for ammonia plant components (Cost are expressed in 2012A$)

	Original				Adjusted			
	Capacity	Cost year	Currency	Original cost	Capacity	Cost year	Currency	Adjusted cost
Hydrogen plant	379 t/day	2005	US$	$ 135 million [a]	38 t/day	2012	A$	$ 43.9 million
ASU	250 t/day	2010	US$	$ 6.90 million	175 t/day	2012	A$	$ 6.50 million
Ammonia synthesis plant	300 t/day	2010	US$	$ 22.5 million	215 t/day	2012	A$	$ 21.5 million
Total						2012	A$	$ 71.9 million

[a] Capital cost obtained from Section 4.5.2.2.2.

A.61. Black coal-based nickel refinery utility system mass balance

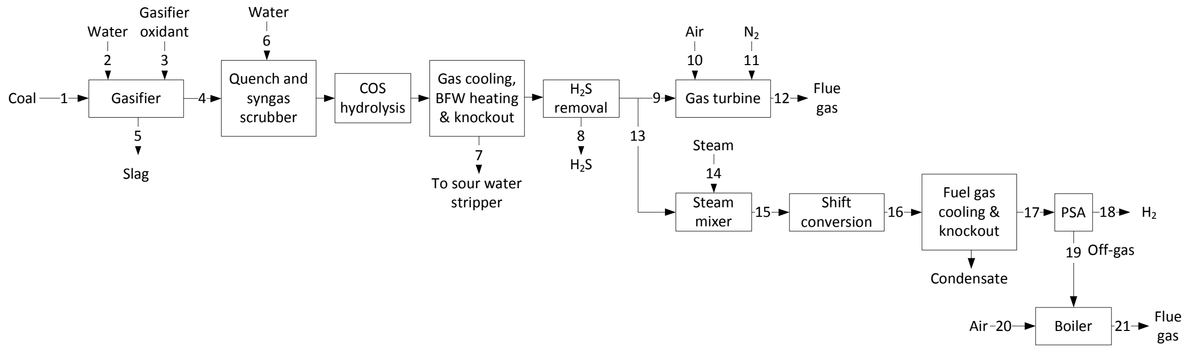

Figure A.13: Coal gasification combined utility (power, steam and chemicals) system mass balance

The combined utility system is designed to produce electricity, steam and chemicals for the nickel refinery. The starting design is similar in design to the coal-to-hydrogen plant in Appendix A.37, which is adapted from Buchanan et al. (2003).

Approximately 0.218 t/hr of H_2S is removed from 47.9 t/hr of coal, which is equivalent to 0.00455 t H_2S recovered for every t coal.

Table A.110: Mass balance for H_2 plant using No. Pittsburgh coal (NETL 2010a)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Mass flow rate (t/hr)	47.9	17.5	30.7	95.1	8.40	24.1	33.2	0.218	59.3	530	94.4	683	24.9	22.0	46.9	46.9	7.30	1.59	5.71	31.2	36.9
Temperature (°C)	-	15.6	158	260	-	260	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	458	50.6	21.1	21.1	31.7	138
Pressure (MPa, abs)	0.101	0.101	4.27	2.70	0.103	3.24	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	2.63	2.33	2.14	0.117	0.117	0.101
Mole fraction (%)																					
Ar	-	0	0.04	0.01	-	0	0		0.01	0.01	0	0.01	0.01	0	0	0.01	0.01	0	0.03	0.01	0.02
CH_4	-	0	0	0	-	0	0		0	0	0	0	0	0	0	0	0.01	0	0.02	0	0
CO	-	0	0	0.41	-	0	0		0.46	0	0	0	0.46	0	0.24	0.06	0.13	0	0.39	0	0
CO_2	-	0	0	0.09	-	0	0		0.11	0	0	0.07	0.11	0	0.06	0.24	0.01	0	0.52	0	0.13
H_2	-	0	0	0.36	-	0	0		0.41	0	0	0	0.41	0	0.21	0.39	0.84	1.00	0.01	0	0
H_2O	-	1.00	0	0.12	-	1.00	1.00		0	0.01	0	0.06	0	1.00	0.48	0.30	0	0	0.01	0.01	0
H_2S	-	0	0	0	-	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0.18
HCl	-	0	0	0	-	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0
N_2	-	0	0.01	0.01	-	0	0		0.01	0.77	0.99	0.65	0.01	0	0	0	0.01	0	0.02	0.77	0.65
NH_3	-	0	0	0	-	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0
O_2	-	0	0.95	0	-	0	0		0	0.21	0.01	0.10	0	0	0	0	0	0	0	0.21	0.03
SO_2	-	0	0	0	-	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0
Total	-	1.00	1.00	1.00	-	1.00	1.00		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

A.62. Black coal-based nickel refinery gas turbine and HRSG HYSYS model

Values taken from mass balance

- Mass of syngas = 59.3 t syngas/hr (Appendix A.62)

Results of modelling

- Syngas Higher Heating Value (HHV) = 13.2 GJ/t
- Steam generated = 137 t/hr (100% efficiency)
  = [(137)(0.85)]/59.3
  = 1.96 t steam/t syngas (85% efficiency)
- Gross electricity generated = 91.1 MW
  = 91.1/59.3 = 1.54 MWh/t syngas

Table A.111: Mass balance for black coal-based nickel refinery gas turbine and HRSG HYSYS model

Stream number	Ambient air feed	Compressed air	Syngas	Nitrogen	Fuel mix	Flue1	Bottom	Flue2	Flue3	BFW	Steam
Vapour fraction	1.00	1.00	1.00	1.00	1.00	1.00	0	1.00	1.00	0	1.00
Temperature (°C)	15.0	455	260	93	382	954	954	558	320	310	311
Pressure (kPa)	101	1620	2700	2650	1620	1620	1620	150	116	10000	10000
Molar flow (kmol/hr)	18400	18400	3110	3400	24900	23500	0	23520	23520	7580	7580
Mass flow (t/hr)	530	530	59.3	95.0	684	684	0	684	684	137	137
Components (mol%)											
CH4	0	0	0	0	0	0.01	0	0	0	0	0
C2H6	0	0	0	0	0	0	0	0	0	0	0
C3H8	0	0	0	0	0	0	0	0	0	0	0
i-C4H10	0	0	0	0	0	0	0	0	0	0	0
n-C4H10	0	0	0	0	0	0	0	0	0	0	0
i-C5H12	0	0	0	0	0	0	0	0	0	0	0
n-C5H12	0	0	0	0	0	0	0	0	0	0	0
n-C6H14	0	0	0	0	0	0	0	0	0	0	0
N2	0.79	0.79	0.01	0.99	0.72	0.76	0	0.76	0.76	0	0
O2	0.21	0.21	0	0.01	0.16	0.13	0	0.13	0.13	0	0
CO2	0	0	0.11	0	0.01	0.06	0	0.06	0.06	0	0
H2O	0	0	0	0	0	0.03	0	0.03	0.03	1.00	1.00
He	0	0	0	0	0	0	0	0	0	0	0
H2	0	0	0.41	0	0.05	0	0	0	0	0	0
CO	0	0	0.46	0	0.06	0	0	0	0	0	0
Ar	0	0	0.01	0	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0	0	0	0	0	0
NH3	0	0	0	0	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	1.00	1.00	1.00	0.00	1.00	1.00	1.00	1.00

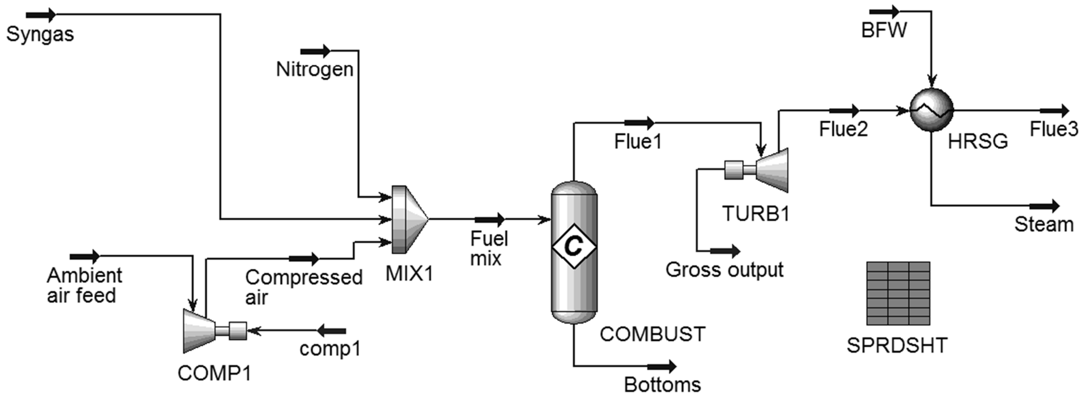

Figure A.14: HYSYS simulation of black coal-based nickel refinery gas turbine and HRSG

A.63. Black coal-based PSA off-gas boiler HYSYS model

Assumptions

- PSA off-gas feed rate = 5.72 t/hr
- Ambient air feed = 31.2 t/hr
- HRSG efficiency = 85%

Results of modelling

- Steam production rate = 28.6 t/hr (100% efficiency)
  = [(28.6)(0.85)]/5.72
  = 4.25 t steam/t syngas (85% efficiency)

Table A.112: Mass balance for black coal-based PSA offgas boiler HYSYS model

Stream number	PSA offgas	Ambient air feed	Flue1	Bottom	Flue2	BFW	Steam
Vapour fraction	1.00	1.00	1.00	0	1.00	0	1
Temperature (°C)	21.1	25.0	1140	1140	320	310	311
Pressure (kPa)	117	117	117	117	17	10000	10000
Molar flow (kmol/hr)	385	1080	1290	0	1293	1590	1590
Mass flow (t/hr)	5.72	31.2	37.0	0	37	28.6	28.6
Components (mol%)							
CH_4	0.02	0	0.04	0	0.04	0	0
C_2H_6	0	0	0	0	0	0	0
C_3H_8	0	0	0	0	0	0	0
i-C_4H_{10}	0	0	0	0	0	0	0
n-C_4H_{10}	0	0	0	0	0	0	0
i-C_5H_{12}	0	0	0	0	0	0	0
n-C_5H_{12}	0	0	0	0	0	0	0
n-C_6H_{14}	0	0	0	0	0	0	0
N_2	0.02	0.79	0.67	0	0.67	0	0
O_2	0	0.21	0.12	0	0.12	0	0
CO_2	0.02	0	0.08	0	0.08	0	0
H_2O	0.01	0	0.08	0	0.08	1.00	1.00
He	0	0	0	0	0	0	0
H_2	0.52	0	0	0	0	0	0
CO	0.39	0	0	0	0	0	0
Ar	0.03	0	0.01	0	0.01	0	0
COS	0	0	0	0	0	0	0
H_2S	0	0	0	0	0	0	0
NH_3	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	0	1.00	1.00	1.00

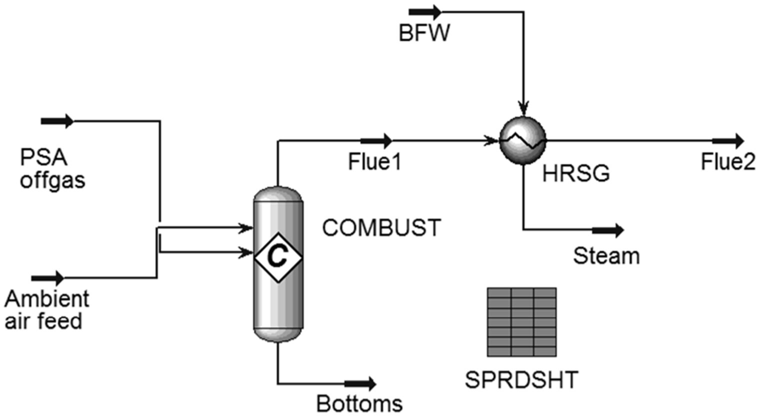

Figure A.15: HYSYS simulation of black coal-based PSA offgas boiler to produce steam

A.64. Black coal-based nickel refinery utility system calculations

Steam is produced from both the PSA off-gas boiler and the gas turbine HRSG. The shift reaction consumes a portion of the steam. As the H_2 plant size is sized to meet the H_2 requirement, the steam production from the PSA off-gas boiler is fixed. The remaining steam is then met by the gas turbine HRSG.

Hydrogen produced = 1.59 t H_2/hr
= 0.185 t H_2/t nickel

Total PSA off-gas produced = 5.72 t PSA off-gas/hr
= 0.668 t PSA off-gas/t nickel

Steam produced from PSA off-gas boiler = 4.25 t steam/t offgas (Appendix A.63)
= (4.25)(5.72) = 24.3 t steam/hr
= 2.84 t steam/t nickel

Steam consumed for shift reaction = 22.0 t steam/hr
= 2.56 t steam/t nickel

Steam available = 24.3 – 22.0 = 2.34 t steam/hr
= 2.84 – 2.56 = 0.27 t steam/t nickel

Syngas consumption and electricity generated using the gas turbine is calculated using the HYSYS factors from Appendix A.52.

Steam produced from gas turbine HRSG = 126 – 2.34 = 123 t steam/hr
= 14.69 – 0.27 = 14.4 t steam/t nickel

Syngas required to produce steam = 1.96 t steam/t syngas (Appendix A.62)
= 123/1.96 = 63.1 t syngas/hr
= 7.37 t syngas/t nickel

Gross electricity produced = 1.54 MWh/t syngas (Appendix A.62)
= (63.1)(1.54) = 96.9 MW
= 11.32 MWh/t nickel

The various auxiliaries and electricity internal usage is deducted from the gross electricity to calculate the net export electricity. The auxiliaries are assumed to be similar to that of an IGCC plant from NETL (2010a).

Refinery requirements = 24.8 MW = 2.90 MWh/t nickel

IGCC auxiliaries = 37.2 MW = 4.35 MWh/t nickel

H_2 plant = 5.5 MW = 0.64 MWh/t nickel

NH_3 synthesis loop = 3.5 MW = 0.41 MWh/t nickel

Net export electricity = 96.9 – 24.8 – 37.2 – 5.5 – 25.8 = 25.8 MW

= 3.02 MWh/t nickel

The nickel refinery requires 0.183 t/hr of H_2S or 0.0213 t H_2S/t nickel. Given that the total amount of coal produced is as follows:

Syngas required for hydrogen production = 25.0 t syngas/hr
= 1.77 t syngas/t nickel

Syngas required for electricity generation = 63.1 t syngas/hr
= 7.37 t syngas/t nickel

Total syngas required = 25.0 + 63.1 = 88.0 t syngas/hr
= 1.77 + 7.37 = 10.3 t syngas/t nickel

Total coal required = 1.76 t syngas/t coal
= 10.3/1.76 = 5.84 t coal/t nickel

Total H_2S produced = 0.00455 t H_2S/t coal (Appendix A.61)
= (0.00455)(5.84) = 0.0266 t H_2S/t nickel

As the amount of H_2S recovered is enough to meet the demand of the nickel refinery, there is no need for a H_2S plant.

A.65. Black coal-based nickel refinery utility system capital cost calculations

(A) The capital costs of equipment were based on IGCC technology costs reported in Bedilion et al. (2009).
(B) The steam turbine and cooling water system is removed.
(C) The gross output of the gas turbine is adjusted to match the gross output of the gas turbine from Appendix A.54. The capital costs for each equipment are adjusted based on the gasifier capacity (i.e. black coal feed consumption in t/hr) using Equation 4.5. The capital costs of the gas turbine and HRSG are adjusted independently based on the turbine capacity (i.e. gross ouput in MW).
(D) The capital cost of the calciner HRSG is added to the total capital costs. Due to the additional syngas and subsequent black coal feedstock required, the gasifier is increased in size and all capital costs are adjusted based on fuel consumption using Equation 4.5.
(E) The capital costs are adjusted for inflation from 2009 to 2012 Australian dollars using Equation 4.5.

$$I_p = I_r\left(\frac{Q_p}{Q_r}\right)^b\left(\frac{F_p}{F_r}\right)L$$

(Equation 4.5)

Assuming:

- Q is based on gross output of gas turbine in MW or black coal consumption in GJ-HHV/hr
- Capacity exponent: b = 0.76 for gas turbine and HRSG only, 0.7 for all other equipment
- Plant cost index: F_r (2009) = 337, F_p (2012) = 370
- No conversion rate L

Table A.113: Adjustment for capital cost of black coal-based nickel refinery utility system

Parameters	A	B	C	D	E
Gas turbine output (MW)	572	572	92.4		
Steam turbine output (MW)	318	0	0		
Auxiliaries (MW)	156	156	37.2		
Net output (MW)	728	416	55.2		
Fuel consumption(GJ-HHV/hr)	6,659	6,659	874	1,220	
Efficiency (%)	39.4	22.5	22.7		
Capital cost	2009A$	2009A$	2009A$	2009A$	2012A$
Coal and fluxant/sorbent handling	84.8	84.8	20.5	25.8	28.4
Coal and fluxant/sorbent prep & feed	353.6	353.6	85.3	107.8	118.5
Feedwater & misc. BOP systems	38.6	38.6	9.3	11.8	13.0
Gasifier (inc. ASU) & accessories	1,123.4	1,123.4	271.2	342.4	376.6
Gas cleanup & piping/flue gas cleanup	161.5	161.5	39.0	49.2	54.1
Combustion turbine & accessories	189.7	189.7	47.6	47.6	52.3
HRSG, ducting and stack	96.5	96.5	24.2	29.0	31.9
Steam turbine generator (inc. ACC)	227.3	0	0.0	0.0	0.0
Cooling water system	41.5	0	0.0	0.0	0.0
Ash/spent sorbent handling	109.3	109.3	26.4	33.3	36.6
Accessory electric plant	130.3	130.3	31.4	39.7	43.7
Instrumentation & controls	38.8	38.8	9.4	11.8	13.0
Improvements to site	38.6	38.6	9.3	11.8	12.9
Buildings & structures	38.4	38.4	9.3	11.7	12.9
Total bare erected cost	2,672.3	2,403.5	582.8	722.0	794.0

A.66. Capital cost of chemical manufacture components in the black coal-based nickel refinery utility system

- Adjustment for hydrogen plant, ASU and ammonia synthesis:

$$I_p = I_r \left(\frac{Q_p}{Q_r}\right)^b \left(\frac{F_p}{F_r}\right) L \qquad \text{(Equation 4.5)}$$

Assuming:

- Capacity exponent: b = 0.733 for hydrogen plant, b = 0.7 for ASU and ammonia synthesis
- CEPCI: F_r (2005) = 292, F_r (2010) = 349, F_p (2012) = 370
- US$ to A$ conversion rate: L (2005) = 1.33, L (2010) = 1.14

Table A.114: Capital cost adjustment for ammonia plant components (Cost are expressed in 2012A$)

	Original				Adjusted			
	Capacity	Cost year	Currency	Original cost	Capacity	Cost year	Currency	Adjusted cost
Hydrogen separation and cleanup	284 t/day	2005	US$	$ 55.4 million [a]	38 t/day	2012	A$	$ 23.1 million
Ammonia synthesis plant	300 t/day	2010	US$	$ 22.6 million	215 t/day	2012	A$	$ 21.6 million
Total						2012	A$	$ 44.7 million

[a] Equipment cost taken from Rutkowski (2008)

A.67. Nickel refinery utility system substitution impact indicator calculations

Step 1: Categorise material flow data into environmental impact categories

Table A.115: Environmental impact indicators for utilities in nickel refineries

Option	Nickel refinery utility system		
Feedstock	NG	BlC	CSG
Technology	Cogen+SMR	IGCC	Cogen+SMR
Environmental impact indicators	**t/t nickel**	**t/t nickel**	**t/t nickel**
Global Warming Potential (GWP)	3.70E+00	1.13E+01	3.70E+00
Acidification Potential (ADP)	4.15E-03	6.87E-04	4.15E-03
Photochemical Oxidation Potential (POP)	1.19E-04	4.99E-06	1.19E-04
Particulate Matter Formation (PMF)	-1.04E-04	3.50E-04	-1.04E-04
Freshwater Withdrawal (FWW)	1.90E+00	3.75E+01	1.90E+00
Saline Water Discharge (SWD)	9.27E-01	3.43E+01	9.27E-01
Solid Waste Generation (SWG)	-2.05E-01	8.80E-01	-2.05E-01
Economic impact indicators	**2012A$/t nickel**	**2012A$/t nickel**	**2012A$/t nickel**
Annualised captial costs	421.5	1,744.5	421.52
Cash operating costs	544.3	1,206.6	448.64
Total operating costs	**965.8**	**2,951.2**	**870.2**

Step 2: Calculate the environmental impacts resulting from substitution of natural gas

Table A.116: Environmental impacts due to substitution of natural gas in nickel refineries in Australia

Option	Nickel refinery utility system	
Feedstock	NG→BlC	NG→CSG
Technology	Cogen+SMR→IGCC	Cogen+SMR
Environmental impact indicators	**t/t nickel**	**t/t nickel**
Global Warming Potential (GWP)	7.59E+00	0.00E+00
Acidification Potential (ADP)	-3.46E-03	0.00E+00
Photochemical Oxidation Potential (POP)	-1.14E-04	0.00E+00
Particulate Matter Formation (PMF)	4.54E-04	0.00E+00
Freshwater Withdrawal (FWW)	3.56E+01	0.00E+00
Saline Water Discharge (SWD)	3.34E+01	0.00E+00
Solid Waste Generation (SWG)	1.09E+00	0.00E+00
Economic impact indicators	**2012A$/t nickel**	**2012A$/t nickel**
Annualised captial costs	1,744.5	0.0
Cash operating costs	662.4	-95.7
Total operating costs	**2,406.9**	**-95.7**

Step 3: Calculate annual environmental impacts

Annual Australian nickel production = 180,700 t/yr

Table A.117: Annual environmental impacts due to substitution of natural gas in Australia's nickel production

Option	Nickel refinery utility system	
Feedstock	NG→BIC	NG→CSG
Technology	Cogen+SMR→IGCC	Cogen+SMR
Environmental impact indicators	**t/yr**	**t/yr**
Global Warming Potential (GWP)	1.54E+05	0.00E+00
Acidification Potential (ADP)	-7.04E+01	0.00E+00
Photochemical Oxidation Potential (POP)	-2.31E+00	0.00E+00
Particulate Matter Formation (PMF)	9.21E+00	0.00E+00
Freshwater Withdrawal (FWW)	7.22E+05	0.00E+00
Saline Water Discharge (SWD)	6.78E+05	0.00E+00
Solid Waste Generation (SWG)	2.20E+04	0.00E+00
Economic impact indicators	**2012A$/yr**	**2012A$/yr**
Annualised captial costs	35.4	0.0
Cash operating costs	13.5	-1.9
Total operating costs	**48.9**	**-1.9**

Step 4: Divide by natural gas substituted

Natural gas substituted in nickel production = 44,800 tonnes

Table A.118: Substitution impact indicators for nickel refineries in Australia

Option	Nickel refinery utility system			
Feedstock	NG→BIC		NG→CSG	
Technology	Extraction and refining	Cogen+SMR→IGCC	Extraction and refining	Cogen+SMR
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t NG substituted**
Global Warming Potential (GWP)	-1.08E-01	3.42E+00	-6.23E-02	0.00E+00
Acidification Potential (ADP)	-6.01E-04	-1.56E-03	-6.08E-04	0.00E+00
Photochemical Oxidation Potential (POP)	-2.65E-04	-5.13E-05	-4.34E-04	0.00E+00
Particulate Matter Formation (PMF)	-3.65E-05	2.04E-04	-7.71E-05	0.00E+00
Freshwater Withdrawal (FWW)	4.36E-02	1.60E+01	-2.88E-01	0.00E+00
Associated Water Withdrawal (AWW)	-2.83E-01	0.00E+00	4.51E+00	0.00E+00
Saline Water Discharge (SWD)	-2.02E-02	1.50E+01	-4.51E-02	0.00E+00
Solid Waste Generation (SWG)	1.06E+01	4.88E-01	4.30E-02	0.00E+00
Economic impact indicators	**2012A$/t NG substituted**		**2012A$/t NG substituted**	
Annualised captial costs	785.0		0.0	
Cash operating costs	298.0		-43.1	
Total operating costs	**1,083.0**		**-43.1**	

Step 5: Normalisation of environmental impacts

Table A.119: Normalised substitution impact indicators for nickel refineries in Australia

Option	Nickel refinery utility system	
Feedstock	NG→BIC	NG→CSG
Technology	Cogen+SMR→IGCC	Cogen+SMR
Environmental impact indicators	**t/t NG substituted**	**t NG substituted**
Global Warming Potential (GWP)	6.06E-09	-1.14E-10
Acidification Potential (ADP)	-1.26E-09	-3.55E-10
Photochemical Oxidation Potential (POP)	-2.87E-09	-3.93E-09
Particulate Matter Formation (PMF)	2.02E-10	-9.29E-11
Freshwater Withdrawal (FWW)	1.95E-10	-3.50E-12
Associated Water Withdrawal (AWW)	-9.04E-10	1.44E-08
Saline Water Discharge (SWD)	2.39E-10	-7.17E-13
Solid Waste Generation (SWG)	1.79E-07	6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised captial costs	785.0	0.0
Cash operating costs	298.0	-43.1
Total operating costs	**1,083.0**	**-43.1**

A.68. Residential heating substitution impact indicator calculations

Step 1: Categorise material flow data into environmental impact categories

Table A.120: Environmental impact indicators for residential heating systems in Australia

Option	Residential heating		
Feedstock	Natural gas	Black coal	CSG
Technology	Ducted gas	Ducted air conditioning	Ducted gas
Environmental impact indicators	**t/GJ_{heat}**	**t/GJ_{heat}**	**t/GJ_{heat}**
Global Warming Potential (GWP)	7.78E-02	3.38E-01	1.50E-01
Acidification Potential (ADP)	1.47E-05	2.04E-04	1.49E-04
Photochemical Oxidation Potential (POP)	3.60E-06	1.47E-04	1.01E-05
Particulate Matter Formation (PMF)	5.04E-06	2.72E-05	8.17E-06
Freshwater Withdrawal (FWW)	8.37E-03	3.30E-02	3.70E-01
Saline Water Discharge (SWD)	1.30E-03	0.00E+00	0.00E+00
Solid Waste Generation (SWG)	2.99E-04	2.26E-04	0.00E+00
Economic impact indicators	**$\text{2012A\$t/GJ}_{\text{heat}}$**	**$\text{2012A\$t/GJ}_{\text{heat}}$**	**$\text{2012A\$t/GJ}_{\text{heat}}$**
Annualised captial costs	13.1	18.5	13.1
Cash operating costs	15.3	17.7	11.9
Total operating costs	28.5	36.2	25.0

Step 2: Calculate the environmental impacts resulting from substitution of natural gas

Table A.121: Environmental impacts due to substitution of natural gas in residential heating systems in Australia

Option	Residential heating	
Feedstock	NG→BlC	NG→CSG
Technology	Ducted gas→Ducted air conditioning	Ducted gas
Environmental impact indicators	**t/GJ_{heat}**	**t/GJ_{heat}**
Global Warming Potential (GWP)	-9.76E-03	0.00E+00
Acidification Potential (ADP)	9.35E-05	0.00E+00
Photochemical Oxidation Potential (POP)	9.47E-07	0.00E+00
Particulate Matter Formation (PMF)	6.03E-06	0.00E+00
Freshwater Withdrawal (FWW)	1.65E-01	0.00E+00
Saline Water Discharge (SWD)	2.47E-02	0.00E+00
Solid Waste Generation (SWG)	6.38E-03	0.00E+00
Economic impact indicators	**$\text{2012A\$/t H}_2$**	**$\text{2012A\$/t H}_2$**
Annualised captial costs	18.4	0.0
Cash operating costs	2.4	-3.5
Total operating costs	**20.8**	**-3.5**

Step 3: Calculate annual environmental impacts

Annual Victorian heating energy consumption = 48,777 GJ_{heat}/yr (Chapter 4.7.1)

Table A.122: Annual environmental impacts due to substitution of natural gas in residential heating systems in Australia

Option	Hydrogen	
Feedstock	NG→BlC	NG→CSG
Technology	Ducted gas→Ducted air conditioning	Ducted gas
Environmental impact indicators	**t/yr**	**t/yr**
Global Warming Potential (GWP)	-4.76E+05	0.00E+00
Acidification Potential (ADP)	4.56E+03	0.00E+00
Photochemical Oxidation Potential (POP)	4.62E+01	0.00E+00
Particulate Matter Formation (PMF)	2.94E+02	0.00E+00
Freshwater Withdrawal (FWW)	8.06E+06	0.00E+00
Saline Water Discharge (SWD)	1.21E+06	0.00E+00
Solid Waste Generation (SWG)	3.11E+05	0.00E+00
Economic impact indicators	**2012A$mil/yr**	**2012A$mil/yr**
Annualised captial costs	899.9	0.0
Cash operating costs	116.9	-169.5
Total operating costs	**1,016.8**	**-169.5**

Step 4: Divide by natural gas substituted

Natural gas substituted in ammonia production = 1.17×10^6 t/yr

Table A.123: Substitution impact indicators for residential heating systems in Australia

Option	Residential heating			
Feedstock	NG→BlC		NG→CSG	
Technology	Extraction and refining	Ducted gas→Ducted air conditioning	Extraction and refining	Ducted gas
Environmental impact indicators	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**	**t/t NG substituted**
Global Warming Potential (GWP)	-1.08E-01	-4.06E-01	-6.23E-02	0.00E+00
Acidification Potential (ADP)	-6.01E-04	3.89E-03	-6.08E-04	0.00E+00
Photochemical Oxidation Potential (POP)	-2.65E-04	3.94E-05	-4.34E-04	0.00E+00
Particulate Matter Formation (PMF)	-3.65E-05	2.51E-04	-7.71E-05	0.00E+00
Freshwater Withdrawal (FWW)	4.36E-02	6.87E+00	-2.88E-01	0.00E+00
Associated Water Withdrawal (AWW)	-2.83E-01	0.00E+00	4.51E+00	0.00E+00
Saline Water Discharge (SWD)	-2.02E-02	1.03E+00	-4.51E-02	0.00E+00
Solid Waste Generation (SWG)	1.06E+01	2.65E-01	4.30E-02	0.00E+00
Economic impact indicators	**2012A$/t NG substituted**		**2012A$/t NG substituted**	
Annualised captial costs	767.2		-	
Cash operating costs	99.7		-144.5	
Total operating costs	**866.9**		**-144.5**	

Step 5: Normalisation of environmental impact indicators

Table A.124: Substitution impact indicators for residential heating systems in Australia

Option	Residential heating	
Feedstock	NG→BlC	NG→CSG
Technology	Ducted gas→Ducted air conditioning	Ducted gas
Environmental impact indicators	**yr/t NG substituted**	**yr/t NG substituted**
Global Warming Potential (GWP)	-9.41E-10	-1.14E-10
Acidification Potential (ADP)	1.92E-09	-3.55E-10
Photochemical Oxidation Potential (POP)	-2.04E-09	-3.93E-09
Particulate Matter Formation (PMF)	2.58E-10	-9.29E-11
Freshwater Withdrawal (FWW)	8.40E-11	-3.50E-12
Associated Water Withdrawal (AWW)	-9.04E-10	1.44E-08
Saline Water Discharge (SWD)	1.60E-11	-7.17E-13
Solid Waste Generation (SWG)	1.75E-07	6.95E-10
Economic impact indicators	**2012A$/t NG substituted**	**2012A$/t NG substituted**
Annualised captial costs	767.2	-
Cash operating costs	99.7	-144.5
Total operating costs	**866.9**	**-144.5**

A.69. Natural gas base case environmental impact indicator data tables

Table A.125: Normalised upstream environmental impact indicators for natural gas extraction and processing

Category	Units	Natural gas extraction and processing
Natural gas produced	t natural gas/yr	2.74E+07
Upstream environmental impact indicators		
Global Warming Potential (GWP)	yr/t natural gas	5.79E-10
Acidification Potential (ADP)	yr/t natural gas	7.43E-10
Photochemical Oxidation Potential (POP)	yr/t natural gas	4.52E-09
Particulate Matter formation (PMF)	yr/t natural gas	9.32E-11
Freshwater Withdrawal (FWW)	yr/t natural gas	3.50E-12
Associated Water Withdrawal (AWW)	yr/t natural gas	1.56E-09
Saline Water Discharge (SWD)	yr/t natural gas	7.17E-13
Solid Waste Generation (SWG)	yr/t natural gas	3.19E-11

Table A.126: Normalised environmental impact indicators for base case of natural gas consumption in Australia (includes both upstream and downstream impacts)

Category	Units	Grid electricity		Mining		Manufacturing			Residential	Total
						Chemicals	Non-ferrous metals		Space heating	
		Baseload	Peaking	Non-grid electricity	Heating	Ammonia	Alumina	Nickel	Ducted heating	
		Combined cycle gas turbine	Open cycle gas turbine	Gas engines	Gas-fired boilers	Steam methane reforming + Haber process	Cogen power and heat	Cogen power and heat + chemicals	Natural gas ducted heating	
Natural gas input	t natural gas/yr	5.90E+06	3.28E+06	4.94E+06	5.49E+05	3.53E+06	5.77E+06	1.54E+05	3.15E+06	2.74E+07
Relative environmental impact indicators										Weighted average
Global Warming Potential (GWP)	yr/t natural gas	5.41E-09	5.41E-09	6.28E-09	5.40E-09	7.02E-09	4.76E-09	3.63E-09	6.50E-09	5.76E-09
Acidification Potential (ADP)	yr/t natural gas	2.28E-09	2.28E-09	4.44E-09	1.04E-09	8.82E-10	1.99E-09	1.83E-09	1.10E-09	2.26E-09
Photochemical Oxidation Potential (POP)	yr/t natural gas	5.96E-09	5.96E-09	1.84E-08	5.60E-09	5.17E-09	5.63E-09	5.00E-09	5.87E-09	8.01E-09
Particulate Matter formation (PMF)	yr/t natural gas	2.67E-10	2.67E-10	9.52E-11	2.86E-10	2.70E-10	1.87E-10	3.69E-11	3.45E-10	2.27E-10
Freshwater Withdrawal (FWW)	yr/t natural gas	8.27E-11	3.50E-12	3.50E-12	3.50E-12	1.62E-10	- 5.92E-12	1.39E-11	7.73E-12	3.98E-11
Associated Water Withdrawal (AWW)	yr/t natural gas	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09
Saline Water Discharge (SWD)	yr/t natural gas	2.49E-11	7.17E-13	7.17E-13	7.17E-13	1.99E-11	5.94E-12	7.36E-12	1.58E-12	9.68E-12
Solid Waste Generation (SWG)	yr/t natural gas	3.19E-11	3.19E-11	3.19E-11	3.19E-11	1.28E-09	- 7.24E-10	- 1.46E-09	2.33E-10	4.89E-11

Note: - sign represents negative emissions, e.g. emissions that have been offset by the natural gas process

A.70. Natural gas base case economic impact indicators

Table A.127: Capital cost impact indicators for base case of natural gas consumption in Australia (includes both upstream and downstream impacts)

Category	Units	Black coal extraction and processing	Grid electricity		Mining		Manufacturing			Residential	Total
							Chemicals	Non-ferrous metals		Space heating	
			Baseload	Peaking	Non-grid electricity	Heating	Ammonia	Alumina	Nickel	Ducted heating	
			Combined cycle gas turbine	Open cycle gas turbine	Gas engines	Gas-fired boilers	Steam methane reforming + Haber process	Cogen power and heat	Cogen power and heat + chemicals	Natural gas ducted heating	
Natural gas substituted	t natural gas/yr	1.84E+07 [a]	5.90E+06	3.28E+06	4.94E+06	5.49E+05	3.53E+06	5.77E+06	1.54E+05	3.15E+06	1.85E+07
Total capital cost indicators											Total
Equivalent no. of units required	-	21.1	7.76	126	369	89.3	10.1	14.1	1.25	2,160,000	--
Unit capital cost	2012A$million	1,050	905	114	4.48	0.432	532	669	288	0.00728	--
Total capital cost	2012A$million	22,100	7,020	14,300	1,650	38.6	5,340	9,450	360	15,700	+ 128,000
Annualised capital cost indicators											Weighted average
Plant life	Years	-	30	30	30	30	30	30	30	15	-
Fractional interest per year	%	-	10	10	10	10	10	10	10	7	-
Annualised capital cost	2012A$/t natural gas	-	126	462	35.5	7.46	160	65.5	216	546	275

[a] Value does not contribute towards total.

Table A.128: Operating cost impact indicators for base case of natural gas consumption in Australia

Category	Units	Grid electricity		Mining		Manufacturing			Residential	Total
						Chemicals	Non-ferrous metals		Space heating	
		Baseload	Peaking	Non-grid electricity	Heating	Ammonia	Alumina	Nickel	Ducted heating	
		Combined cycle gas turbine	Open cycle gas turbine	Gas engines	Gas-fired boilers	Steam methane reforming + Haber process	Cogen power and heat	Cogen power and heat + chemicals	Natural gas ducted heating	
Input	t natural gas/yr	5.90E+06	3.28E+06	4.94E+06	5.49E+05	3.53E+06	5.77E+06	1.54E+05	3.15E+06	2.73E+07
Economic impact indicators										Weighted average
Annualised captial cost	2011A$/t natural gas	126	462	35.5	7.46	160	65.5	216	546	275
Cash operating cost [a]	2012A$/t natural gas	289	552	544	1,150	330	159	255	650	477
Total operating cost [b]	2012A$/t natural gas	416	1,020	580	1,150	491	224	470	1,200	752

[a] Upstream costs are assimilated into the cash operating costs of downstream processes.

[b] Total operating costs is the sum of annualised capital costs and cash operating costs.

A.71. Black coal substitution case environmental impact indicators

Table A.129: Normalised upstream environmental impact indicators for substitution of natural gas with black coal

Category	Units	Black coal extraction and processing
Natural gas substituted	t natural gas/yr	1.85E+07
Black coal output	t black coal/yr	4.73E+07
Upstream environmental impact indicators		
Global Warming Potential (GWP)	yr/t natural gas	- 1.98E-10
Acidification Potential (ADP)	yr/t natural gas	- 3.51E-10
Photochemical Oxidation Potential (POP)	yr/t natural gas	- 2.40E-09
Particulate Matter formation (PMF)	yr/t natural gas	- 4.40E-11
Freshwater Withdrawal (FWW)	yr/t natural gas	+ 5.30E-13
Associated Water Withdrawal (AWW)	yr/t natural gas	- 9.04E-10
Saline Water Discharge (SWD)	yr/t natural gas	- 3.22E-13
Solid Waste Generation (SWG)	yr/t natural gas	+ 1.71E-07

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table A.130: Normalised environmental impact indicators for base case substitution of natural gas with black coal in Australia (includes both upstream and downstream impacts)

Category	Units	Grid electricity	Manufacturing			Residential	Total
			Chemicals	Non-ferrous metals		Space heating	
		Baseload	Ammonia	Alumina	Nickel	Ducted heating	
		Supercritical pulverised coal steam turbines	Coal gasifier + ammonia synthesis	Coal gasifier + gas turbine + HRSG	Coal gasifier + gas turbine + HRSG + chemicals	Reverse cycle 5 star + grid electricity	
Natural gas substituted	t natural gas/yr	5.90E+06	3.52E+06	5.77E+06	1.54E+05	3.15E+06	1.85E+07
Black coal input	t black coal/yr	1.57E+07	1.07E+07	1.64E+07	4.03E+05	3.87E+06	4.71E+07
Environmental impact indicators							Weighted average
Global Warming Potential (GWP)	yr/t natural gas	+ 5.52E-09	+ 7.90E-09	+ 5.62E-09	+ 6.06E-09	- 9.41E-10	+ 4.91E-09
Acidification Potential (ADP)	yr/t natural gas	+ 3.46E-09	+ 8.23E-08	- 1.44E-09	- 1.26E-09	+ 1.92E-09	+ 1.67E-08
Photochemical Oxidation Potential (POP)	yr/t natural gas	- 3.56E-10	- 1.52E-09	- 3.46E-09	- 2.87E-09	- 2.04E-09	- 1.86E-09
Particulate Matter formation (PMF)	yr/t natural gas	+ 9.12E-10	+ 3.86E-10	+ 2.88E-11	+ 2.02E-10	+ 2.58E-10	+ 4.19E-10
Freshwater Withdrawal (FWW)	yr/t natural gas	+ 9.99E-11	+ 1.46E-10	- 7.20E-12	+ 1.95E-10	+ 8.40E-11	+ 5.95E-11
Associated Water Withdrawal (AWW)	yr/t natural gas	- 9.04E-10	- 9.04E-10	- 9.04E-10	- 9.04E-10	- 9.04E-10	- 9.04E-10
Saline Water Discharge (SWD)	yr/t natural gas	+ 1.06E-11	+ 8.31E-12	- 1.72E-12	+ 2.39E-10	+ 1.60E-11	+ 8.91E-12
Solid Waste Generation (SWG)	yr/t natural gas	+ 1.80E-07	+ 2.16E-07	+ 1.80E-07	+ 1.79E-07	+ 1.75E-07	+ 1.86E-07

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

A.72. Black coal substitution case economic impact indicators

Table A.131: Capital cost impact indicators for base case substitution of natural gas with black coal in Australia

Category	Units	Black coal extraction and processing	Grid electricity	Manufacturing			Residential	Total
				Chemicals	Non-ferrous metals		Space heating	
			Baseload	Ammonia	Alumina	Nickel	Ducted heating	
			Supercritical pulverised coal steam turbines	Coal gasifier + ammonia synthesis	Coal gasifier + gas turbine + HRSG	Coal gasifier + gas turbine + HRSG + chemicals	Reverse cycle 5 star + grid electricity	
Natural gas substituted	t natural gas/yr	1.84E+07 [a]	5.90E+06	3.52E+06	5.77E+06	1.54E+05	3.15E+06	1.85E+07
Black coal input	t black coal/yr	4.60E+07 [a]	1.57E+07	1.07E+07	1.64E+07	4.03E+05	3.87E+06	4.71E+07
Total capital cost indicators								Total
Equivalent no. of units required	-	9.46	7.76	10.0	14.1	1.25	2,160,000	--
Unit capital cost	2012A$million	319	2,840	978	4,410	1,050	0.0117	--
Total capital cost	2012A$million	+ 3,020	+ 22,100	+ 9,830	+ 62,200	+ 1,3100	+ 25,100	+ 128,000
Annualised capital cost indicators								Weighted average
Plant life	Years	-	30	30	30	30	15	-
Fractional interest per year	%	-	10	10	10	10	7	-
Annualised capital cost	2012A$/t natural gas substituted	-	+ 317	+ 288	+ 438	+ 785	+ 767	+ 430

[a] Value does not contribute towards total.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table A.132: Operating cost impact indicators for base case substitution of natural gas with black coal in Australia

Category	Units	Grid electricity	Manufacturing			Residential	Total
			Chemicals	Non-ferrous metals		Space heating	
		Baseload	Ammonia	Alumina	Nickel	Ducted heating	
		Supercritical pulverised coal steam turbines	Coal gasifier + ammonia synthesis	Coal gasifier + gas turbine + HRSG	Coal gasifier + gas turbine + HRSG + chemicals	Reverse cycle 5 star + grid electricity	
Natural gas substituted	t natural gas/yr	5.90E+06	3.52E+06	5.77E+06	1.54E+05	3.15E+06	1.85E+07
Black coal input	t black coal/yr	1.57E+07	8.53E+06	1.63E+07	3.88E+06	3.87E+06	4.48E+07
Cash operating cost indicators							Weighted average
Annualised capital cost	2012A$/t natural gas substituted	+ 317	+ 288	+ 438	+ 785	+ 767	+ 430
Cash operating cost [a]	2012A$/t natural gas substituted	+ 18.7	+ 218	+ 59.9	+ 288	+ 100	+ 85.8
Total operating cost	2012A$/t natural gas substituted	+ 336	+ 506	+ 498	+ 1,070	+ 867	+ 516

[a] Upstream costs are assimmilated into the cash operating costs of downsteam processes.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

A.73. Diesel substitution case environmental impact indicators

Table A.133: Normalised upstream environmental impact indicators for base case substitution of natural gas with diesel in Australia

Category	Units	Diesel extraction and processing
Natural gas substituted	t natural gas/yr	8.77E+06
Diesel output	t diesel/yr	1.00E+07
Crude oil input	t crude oil/yr	1.10E+07
Upstream environmental impact indicators		
Global Warming Potential (GWP)	yr/t natural gas	+ 1.43E-10
Acidification Potential (ADP)	yr/t natural gas	+ 4.39E-10
Photochemical Oxidation Potential (POP)	yr/t natural gas	+ 3.77E-10
Particulate Matter formation (PMF)	yr/t natural gas	+ 1.38E-10
Freshwater Withdrawal (FWW)	yr/t natural gas	- 1.23E-12
Associated Water Withdrawal (AWW)	yr/t natural gas	+ 4.31E-10
Saline Water Discharge (SWD)	yr/t natural gas	+ 5.02E-15
Solid Waste Generation (SWG)	yr/t natural gas	+ 3.76E-11

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table A.134: Normalised environmental impact indicators for base case substitution of natural gas with diesel in Australia (includes both upstream and downstream impacts)

Category	Units	Grid electricity	Mining		Total
		Peaking	Non-grid electricity	Heating	
		Diesel engines	Diesel engines	Diesel boilers	
Natural gas substituted	t natural gas/yr	3.28E+06	4.94E+06	5.49E+05	8.77E+06
Diesel input	t diesel/yr	3.46E+06	5.275E+06	6.79E+05	9.89E+06
Environmental impact indicators					Weighted average
Global Warming Potential (GWP)	yr/t natural gas	+ 1.53E-09	+ 1.32E-09	+ 2.62E-09	+ 1.48E-09
Acidification Potential (ADP)	yr/t natural gas	+ 1.52E-08	+ 1.47E-08	+ 1.53E-09	+ 1.41E-08
Photochemical Oxidation Potential (POP)	yr/t natural gas	+ 2.04E-08	+ 1.02E-08	+ 4.86E-10	+ 1.34E-08
Particulate Matter formation (PMF)	yr/t natural gas	+ 2.55E-09	+ 2.99E-09	+ 1.54E-10	+ 2.65E-09
Freshwater Withdrawal (FWW)	yr/t natural gas	- 1.23E-12	- 1.23E-12	- 1.23E-12	- 1.23E-12
Associated Water Withdrawal (AWW)	yr/t natural gas	+ 4.31E-10	+ 4.31E-10	+ 4.31E-10	+ 4.31E-10
Saline Water Discharge (SWD)	yr/t natural gas	+ 5.02E-15	+ 5.02E-15	+ 5.02E-15	+ 5.02E-15
Solid Waste Generation (SWG)	yr/t natural gas	+ 3.76E-11	+ 3.76E-11	+ 3.76E-11	+ 3.76E-11

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

A.74. Diesel substitution case economic impact indicators

Table A.135: Capital cost impact indicators for base case substitution of natural gas with diesel in Australia

Category	Units	Grid electricity	Mining		Total
			Non-grid electricity	Heating	
		Peaking	Ammonia	Ducted heating	
		Diesel engines	Diesel engines	Diesel boilers	
Natural gas substituted	t natural gas/yr	3.28E+06	4.94E+06	5.49E+05	8.77E+06
Diesel input	t diesel/yr	3.46E+06	5.75E+06	6.79E+05	9.89E+06
Total capital cost indicators					Total
Equivalent no. of units required	-	126	369	89.3	-
Unit capital cost	2012A$million	41.9	3.09	0.540	-
Total capital cost	2012A$million	+ 5,270	+ 1,140	+ 48.3	+ 6,460
Annualised capital cost indicators					Weighted average
Plant life	Years	30	30	30	-
Fractional interest per year	%	15	15	15	-
Annualised capital cost	2012A$/t natural gas substituted	+ 170	+ 24.5	+ 1.10	+ 77.6

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table A.136: Operating cost impact indicators for base case substitution of natural gas with diesel in Australia

Category	Units	Grid electricity	Mining		Total
			Non-grid electricity	Heating	
		Peaking	Ammonia	Ducted heating	
		Diesel engines	Diesel engines	Diesel boilers	
Natural gas substituted	t natural gas/yr	3.28E+06	4.94E+06	5.49E+05	8.77E+06
Diesel input	t diesel/yr	3.46E+06	5.75E+06	6.79E+05	9.89E+06
Cash operating cost indicators					Weighted average
Annualised capital cost	2012A$/t natural gas substituted	+ 170	+ 24.5	+ 1.10	+ 77.6
Cash operating cost [a]	2012A$/t natural gas substituted	+ 825	+ 1,120	+ 161	+ 950
Total operating cost	2012A$/t natural gas substituted	+ 995	+ 1,140	+ 162	+ 1,030

[a] Upstream costs are assimilated into the cash operating costs of downsteam processes.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

A.75. Combined system-wide case environmental impact indicators

Table A.137: Normalised environmental impact indicators for base case substitution of natural gas with black coal and diesel in Australia (includes both upstream and downstream impacts)

Category	Units	Weighted average for black coal	Weighted average for diesel	Weighted average for total system
Global Warming Potential (GWP)	yr/t natural gas	+ 4.91E-09	+ 1.48E-09	+ 3.81E-09
Acidification Potential (ADP)	yr/t natural gas	+ 1.67E-08	+ 1.41E-08	+ 1.59E-08
Photochemical Oxidation Potential (POP)	yr/t natural gas	- 1.86E-09	+ 1.34E-08	- 3.06E-09
Particulate Matter formation (PMF)	yr/t natural gas	+ 4.57E-10	+ 2.65E-09	+ 1.17E-09
Freshwater Withdrawal (FWW)	yr/t natural gas	+ 7.33E-11	- 1.23E-12	+ 4.94E-11
Associated Water Withdrawal (AWW)	yr/t natural gas	- 9.04E-10	+ 4.31E-10	- 4.75E-10
Saline Water Discharge (SWD)	yr/t natural gas	+ 9.14E-12	+ 5.02E-15	+ 6.21E-12
Solid Waste Generation (SWG)	yr/t natural gas	+ 1.86E-07	+ 3.76E-11	+ 1.26E-07

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case.

A.76. Combined system-wide case economic impact indicators

Table A.138: Normalised economic impact indicators for base case substitution of natural gas with black coal and diesel in Australia (includes both upstream and downstream impacts)

Category	Units	Total for black coal	Total for diesel	Total system
Total capital cost indicator	2012A$million	+ 119,000	+6,460	+ 126,000
Category	Units	Weighted average for black coal	Weighted average for diesel	Weighted average for total system
Annualised capital cost	2012A$/t natural gas substituted	+ 430	+ 77.6	+ 363.6
Cash operating cost	2012A$/t natural gas substituted	+ 85.8	+ 950	+ 316.7
Total operating cost	2012A$/t natural gas substituted	+ 516	+ 1,030	+ 680.3

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case.

A.77. CSG substitution case environmental impact indicators

Table A.139: Normalised upstream environmental impact indicators for base case substitution of natural gas with CSG in Australia

Category	Units	Upstream extraction and processing
Natural gas substituted	t natural gas/yr	2.74E+07
CSG input	t CSG/yr	2.74E+07
Upstream environmental impact indicators		
Global Warming Potential (GWP)	t/t natural gas substituted	- 1.14E-10
Acidification Potential (ADP)	t/t natural gas substituted	- 3.55E-10
Photochemical Oxidation Potential (POP)	t/t natural gas substituted	- 3.93E-09
Particulate Matter Formation (PMF)	t/t natural gas substituted	- 9.29E-11
Freshwater Withdrawal (FWW)	t/t natural gas substituted	- 3.50E-12
Associated Water Withdrawal (AWW)	t/t natural gas substituted	+ 1.44E-08
Saline Water Discharge (SWD)	t/t natural gas substituted	- 7.17E-13
Solid Waste Generation (SWG)	t/t natural gas substituted	+ 6.95E-10

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

A.78. CSG substitution case economic impact indicators

Table A.140: Capital cost impact indicators for base case substitution of natural gas with CSG in Australia

Category	Units	Value
Natural gas substituted	t natural gas/yr	2.74E+07
CSG input	t CSG/yr	2.74E+07
Capital cost original indicators		Value
Equivalent no. of units required	-	50.3
Unit capital cost	2012A$million	428
Total capital cost	2012A$million	+ 21,500
Annualised capital cost indicator		Value
Plant life	Years	30
Fractional interest per year	%	10
Annualised capital cost	2012A$/t natural gas substituted	+ 83.4

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

Table A.141: Operating cost impact indicators for substitution of natural gas with CSG in Australia

Category	Units	Grid electricity		Mining		Manufacturing			Residential	Total
						Chemicals	Non-ferrous metals		Space heating	
		Baseload	Peaking	Non-grid electricity	Heating	Ammonia	Alumina	Nickel	Ducted heating	
		Combined cycle gas turbine	Open cycle gas turbine	Gas engines	Gas-fired boilers	Steam methane reforming + Haber process	Cogen power and heat	Cogen power and heat + chemicals	Natural gas ducted heating	
Natural gas substituted	t natural gas/yr	5.90E+06	3.28E+06	4.94E+06	5.49E+05	3.52E+06	5.77E+06	1.54E+05	3.15E+06	2.73E+07
CSG input	t CSG/yr	5.90E+06	3.28E+06	4.94E+06	5.49E+05	3.52E+06	5.77E+06	1.54E+05	3.15E+06	2.73E+07
Cash operating cost indicator										Weighted average
Cash operating cost [a]	2012A$/t natural gas substituted	- 45.4	- 45.4	- 45.4	- 4.7	- 61.6	- 43.2	-43.0	- 144	- 52.2

[a] Upstream costs are assimilated into the cash operating costs of downsteam processes.

Note: + sign represents an increase relative to natural gas base case while - sign represents a decrease relative to natural gas base case

A.79. Sensitivity analysis modelling and results

In this appendix, I will demonstrate how I use HYSYS modelling to estimate the CO_2 emissions from the gas processing plant, which I use to analyse the effects of variation in raw natural gas composition on the CO_2 emissions from natural gas upstream processes. The gas processing plant model for natural gas sourced from Ballera is used as an example. The Ballera wellhead natural gas is modelled in HYSYS based on the properties and composition given in Brennan (2012).

The Ballera natural gas was said to be saturated with water. This was simulated by adding water to the wellhead natural gas at the same temperature and pressure and passing the combined streams through a separator to remove excess water. The mixture is then passed through a 3-phase separator that separates dry gas from liquids and water. The liquids is sent to the demethaniser to extract methane from the liquids, while the dry gas is directed to the sweetening unit to extract H_2S and CO_2 from the gas. The sweetening unit uses DEA. These procedures are shown in Figure A.16.

The gas is then sent to the dehydration unit to remove water. The dehydration unit uses Tri-Ethylene Glycol (TEG). This procedure is shown in Figure A.17.

The gas is then sent through a turbo-expander to separate methane and higher hydrocarbons. This procedure is shown in Figure A.18 and Figure A.19.

The following equipment in the gas processing plant were available in HYSYS as in-built example cases:

Sweetener	– Acid Gas Sweetening with DEA.hsc
Dehydration	– Natural Gas Dehydration with TEG.hsc
Demethaniser	– Deep Cut Turbo-Expander Plant.hsc
Depropaniser	– De-Propanizer – Dynamic Model.hsc
Debutaniser	– Debutanizer Column – Dynamic Model.hsc

The sweetening and dehydration unit was available at a default size. The starting mass flowrate of the wellhead gas is adjusted to the maximum size that can be accommodated by the sweetening unit. This mass flowrate is used for subsequent HYSYS models for the gas processing plant.

(a) Sweetening unit

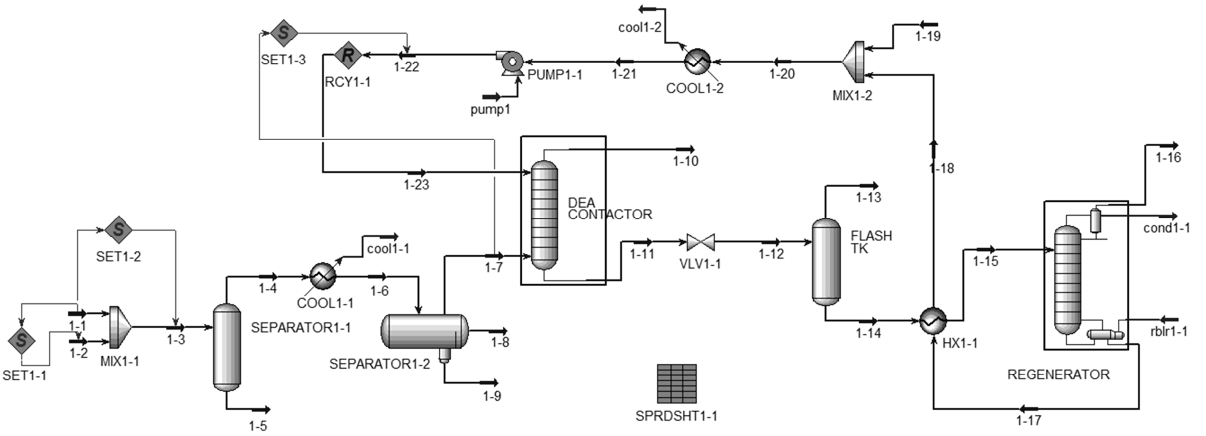

Figure A.16: HYSYS schematic of sweetening unit in gas processing plant

Table A.142: Energy table for sweetening unit in gas processing plant

Name	Energy type	Value (MW)
cool1-1	Cooling	0.467
cool1-2	Cooling	2.48
cond1-1	Cooling	0.944
rlbr1-1	Heating	3.97
pump1-1	Electricity	0.127

Table A.143: Mass balance for sweetening unit in gas processing plant

Stream number	1-1	1-2	1-3	1-4	1-5	1-6	1-7	1-8	1-9	1-10	1-11	1-12	1-13	1-14	1-15	1-16	1-17	1-18	1-19	1-20	1-21	1-22	1-23
Vapour fraction	1.00	1.00	1.00	1.00	0	0.92	1.00	0	0	1.00	0	0	1.00	0	0.01	1.00	0	0	0	0	0	0	0
Temperature (°C)	60.0	413	60.0	60.0	60.0	24.0	24.0	24.0	24.0	36.0	60.6	60.0	60.0	60.0	93.3	82.0	124	85.7	21.1	84.8	32.2	35.0	35.0
Pressure (kPa)	8100	31100	8100	8100	8100	8101	8101	8101	8101	6860	6900	621	621	621	552	190	217	148	148	148	114	8070	8070
Molar flow (kmol/hr)	550	2.10	552	552	0	552	507	43	2	420	1970	1970	4	1970	1970	114	1860	1860	32	1890	1890	1890	1890
Mass flow (t/hr)	14.7	0.0378	14.7	14.7	0	14.7	12.7	1.96	0.0303	8.9	48.0	48.0	0.142	47.9	47.9	4.22	43.7	43.7	0.571	44.3	44.3	44.3	44.3
Components (mol%)																							
N2	0.02	0	0.02	0.02	0.02	0.02	0.02	0	0	0.02	0	0.00	0	0	0	0	0	0	0	0	0	0	0
CO2	0.18	0	0.18	0.18	0.18	0.18	0.18	0.15	0.01	0.02	0	0.04	1	0.04	0.04	0.73	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH4	0.62	0	0.61	0.61	0.61	0.61	0.64	0.30	0	0.77	0	0	0	0	0	0	0	0	0	0	0	0	0
C2H6	0.10	0	0.10	0.10	0.10	0.10	0.10	0.13	0	0.12	0	0	0	0	0	0	0	0	0	0	0	0	0
C3H8	0.04	0	0.04	0.04	0.04	0.04	0.03	0.09	0	0.04	0	0	0	0	0	0	0	0	0	0	0	0	0
i-C4H10	0.01	0	0.01	0.01	0.01	0.01	0	0.02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
n-C4H10	0.01	0	0.01	0.01	0.01	0.01	0.01	0.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
i-C5H12	0	0	0	0	0	0	0	0.02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
n-C5H12	0	0	0	0	0	0	0	0.03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
n-C6H14	0.03	0	0.03	0.03	0.03	0.03	0.01	0.22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heptane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H2O	0	1.00	0	0	0	0	0	0	0.99	0	0.90	0.90	0	0.90	0.90	0.27	0.94	0.94	1.00	0.94	0.94	0.94	0.94
DEA	0	0	0	0	0	0	0	0	0	0	0	0.06	0	0.06	0.06	0	0.06	0.06	0	0.06	0.06	0.06	0.06
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

(b) Dehydration unit

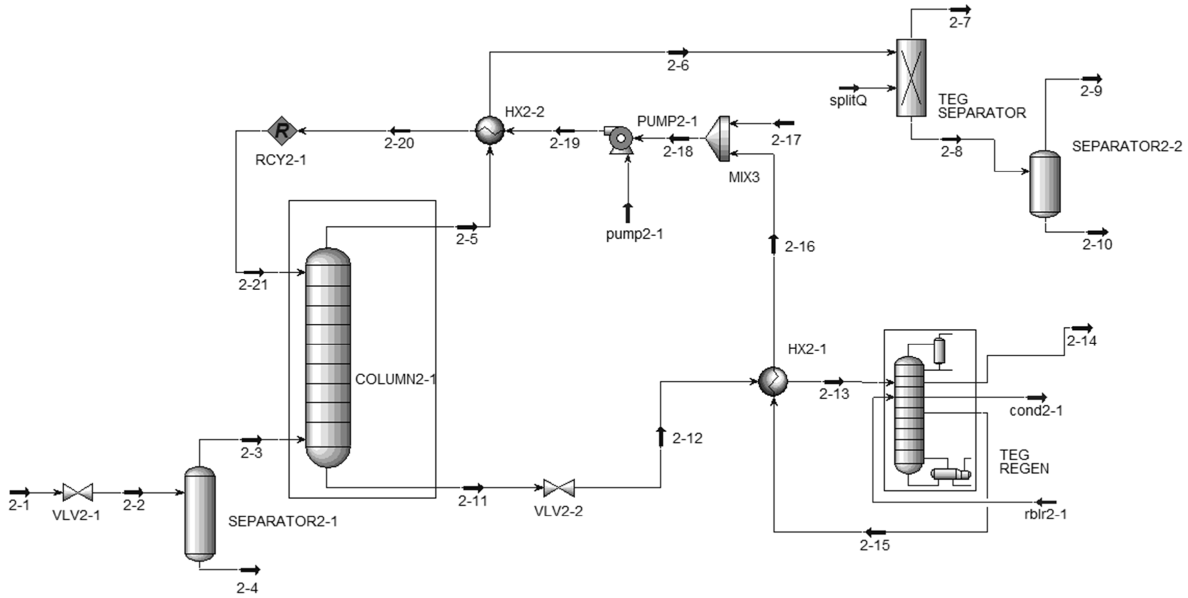

Figure A.17: HYSYS schematic of dehydration unit in gas processing plant

Table A.144: Energy table for dehydration unit in gas processing plant

Name	Energy type	Value (MW)
splitQ	Heating	0.00975
cond2-1	Cooling	0.000298
rlbr2-1	Heating	0.0446
pump2-1	Electricity	0.00115

Table A.145: Mass balance for dehydration unit in gas processing plant

Stream number	2-1	2-2	2-3	2-4	2-5	2-6	2-7	2-8	2-9	2-10	2-11	2-12	2-13	2-14	2-15	2-16	2-17	2-18	2-19	2-20	2-21
Vapour fraction	1.00	1.00	1.00	0	1.00	1.00	0	1.00	1.00	0	0	0.03	0	1.00	0	0	0	0	0	0	0
Temperature (°C)	36.0	33.1	33.1	33	34	38.9	-13.9	41.5	42	41.5	33.3	39	104	102	204	148	15.6	148	147	48.9	48.9
Pressure (kPa)	6860	6200	6200	6200	6000	5970	6170	6170	6170	6170	6100	179	110	101	103	103	103	103	6270	6210	6210
Molar flow (kmol/hr)	420	420	419	1.12	419	419	0	419	419	0	4.21	4.21	4.21	0.561	3.65	3.65	0	3.65	3.65	3.65	3.65
Mass flow (t/hr)	8.91	8.91	8.85	0.0568	8.84	8.84	2.31E-05	8.84	8.84	0	0.523	0.523	0.523	0.0115	0.512	0.512	0	0.512	0.512	0.512	0.512
Components (mol%)																					
N2	0.02	0.02	0.02	0	0.01	0.02	0	0.02	0.02	0	0	0	0	0.02	0	0	0	0	0	0	0
CO2	0.02	0.02	0.02	0.01	0.01	0.02	0	0.02	0.02	0.01	0	0	0	0.03	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH4	0.77	0.77	0.78	0.22	0.69	0.78	0	0.78	0.78	0.28	0.02	0.02	0.02	0.12	0	0	0	0	0	0	0
C2H6	0.12	0.12	0.12	0.12	0.17	0.12	0	0.12	0.12	0.13	0.01	0.01	0.01	0.05	0	0	0	0	0	0	0
C3H8	0.04	0.04	0.04	0.09	0.06	0.04	0	0.04	0.04	0.10	0	0	0	0.03	0	0	0	0	0	0	0
i-C4H10	0.01	0.01	0.01	0.03	0.01	0.01	0	0.01	0.01	0.03	0	0	0	0	0	0	0	0	0	0	0
n-C4H10	0.01	0.01	0.01	0.06	0.02	0.01	0	0.01	0.01	0.06	0	0	0	0	0	0	0	0	0	0	0
i-C5H12	0	0	0	0.02	0	0	0	0	0	0.02	0	0	0	0	0	0	0	0	0	0	0
n-C5H12	0	0	0	0.03	0	0	0	0	0	0.04	0	0	0	0	0	0	0	0	0	0	0
TEGlycol	0	0	0	0	0	0	1.00	0	0	0	0.80	0.80	0.80	0	0.92	0.92	0.99	0.92	0.92	0.92	0.99
H2O	0	0	0	0.09	0	0	0	0	0	0	0.16	0.16	0.16	0.74	0.08	0.08	0.01	0.08	0.08	0.08	0.01
n-C6H14	0.01	0.01	0.01	0.33	0.02	0.01	0	0.01	0.01	0.32	0	0	0	0	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

(c) Demethaniser

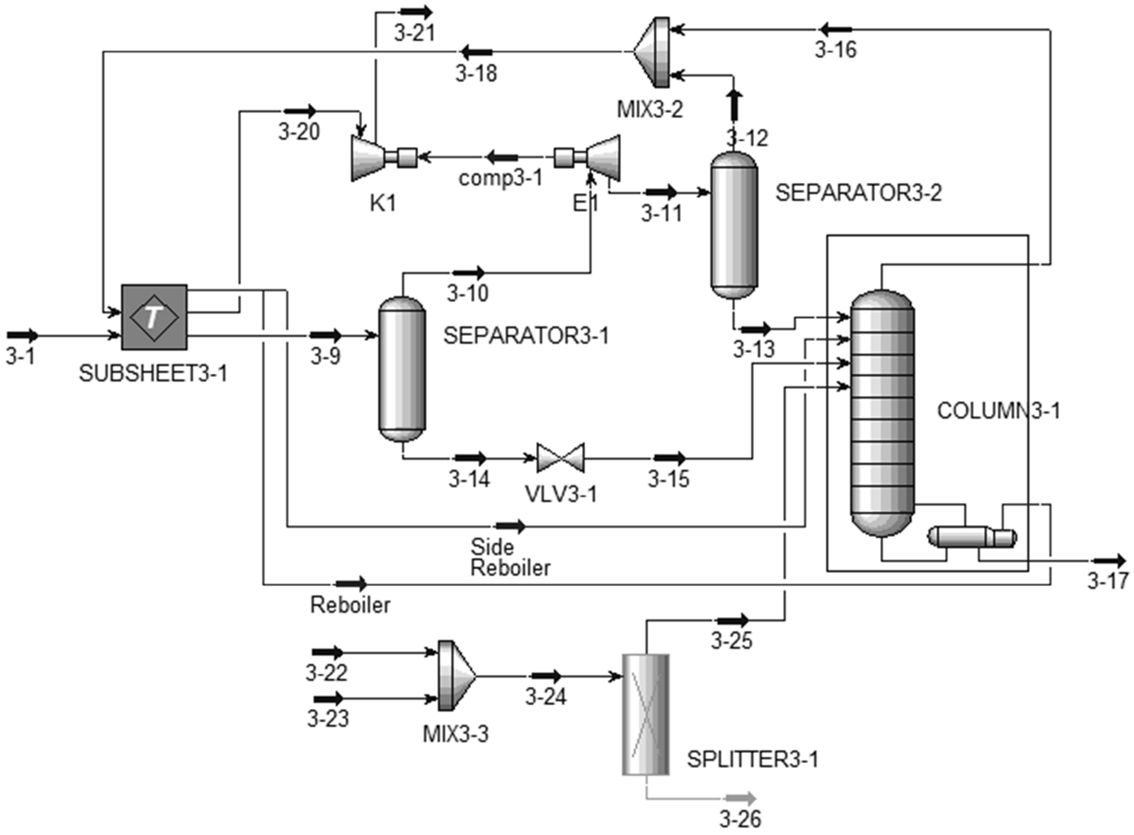

Figure A.18: HYSYS schematic of demethaniser in gas processing plant (Part 1)

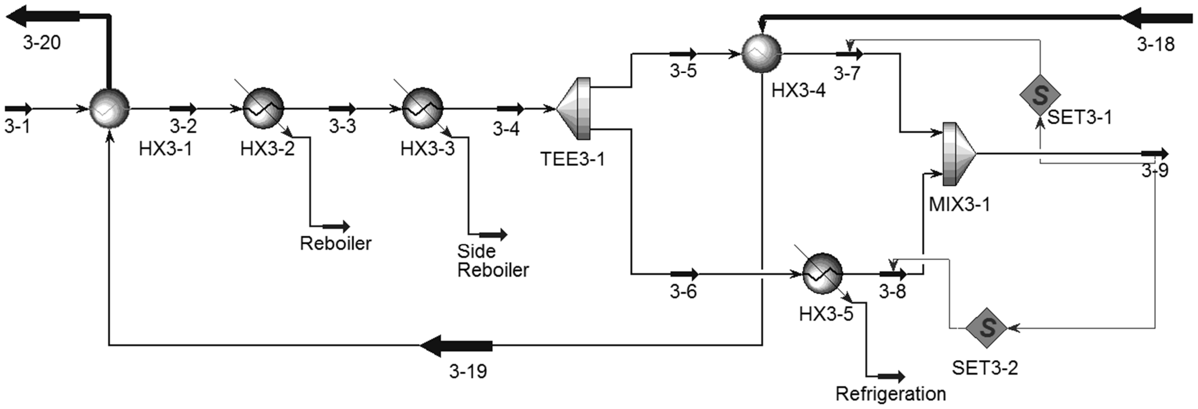

Figure A.19: HYSYS schematic of demethaniser in gas processing plant (Part 2)

Table A.146: Mass balance for demethaniser in gas processing plant

Stream number	3-1	3-2	3-3	3-4	3-5	3-6	3-7	3-8	3-9	3-10	3-11	3-12	3-13
Vapour fraction	1.00	0.98	0.97	0.96	0.96	0.96	0.84	0.84	0.84	1.00	0.90	1.00	0
Temperature (°C)	41.5	19.0	13.0	2.00	2.00	2.00	-30.0	-30.0	-30.0	-30.0	-81.6	-81.6	-81.6
Pressure (kPa)	6170	6140	6102	6070	6070	6070	6030	6030	6030	6030	1500	1500	1500
Molar flow (kmol/hr)	418	418	418	418	418	0	418	0	418	351	351	317	33.8
Mass flow (t/hr)	8.84	8.84	8.84	8.84	8.84	0	8.84	0	8.84	6.62	6.62	5.60	1.02
Components (mol%)													
N2	0.02	0.02	0.02	0.02	0.02	0	0.02	0	0.02	0.02	0.02	0.03	0
CO2	0.02	0.02	0.02	0.02	0.02	0	0.02	0	0.02	0.01	0.01	0.01	0.03
CH4	0.78	0.78	0.78	0.78	0.78	0	0.78	0	0.78	0.84	0.84	0.90	0.31
C2H6	0.12	0.12	0.12	0.12	0.12	0	0.12	0	0.12	0.10	0.10	0.06	0.43
C3H8	0.04	0.04	0.04	0.04	0.04	0	0.04	0	0.04	0.02	0.02	0.00	0.18
i-C4H10	0.01	0.01	0.01	0.01	0.01	0	0.01	0	0.01	0	0	0	0.02
n-C4H10	0.01	0.01	0.01	0.01	0.01	0	0.01	0	0.01	0	0	0	0.02
i-C5H12	0	0	0	0	0	0	0	0	0	0	0	0	0
n-C5H12	0	0	0	0	0	0	0	0	0	0	0	0	0
n-C6H14	0.01	0.01	0.01	0.01	0.01	0	0.01	0	0.01	0	0	0	0
H2O	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1.00	1.00	1.00	1.00	1.00	0.00	1.00	0.00	1.00	1.00	1.00	1.00	1.00

Table A.146: Mass balance for demethaniser in gas processing plant (continued)

Stream number	3-14	3-15	3-16	3-17	3-18	3-19	3-20	3-21	3-22	3-23	3-24	3-25	3-26
Vapour fraction	0	0.40	1.00	0	1.00	1.00	1.00	1.00	0.0439	0	0.188	0.247	<empty>
Temperature (°C)	-30.0	-57.7	-53	7	-75	-3.16	35.3	69.2	24	33.1	19.5	30.2	<empty>
Pressure (kPa)	6030	1550	1500	1550	1500	1470	1430	2060	8100	6200	6200	6200	6200
Molar flow (kmol/hr)	67.8	67.8	72	74	389	389	389	389	43.4	1.1	44.5	44.4	0.2
Mass flow (t/hr)	2.22	2.22	1.53	3.73	7.13	7.13	7.13	7.13	1.96	0.0568	2.02	2.02	0
Components (mol%)													
N2	0	0	0.01	0	0.02	0.02	0.02	0.02	0	0	0	0	0
CO2	0.02	0.02	0.08	0.04	0.03	0.03	0.03	0.03	0.15	0.01	0.15	0.15	0
CH4	0.45	0.45	0.73	0.02	0.87	0.87	0.87	0.87	0.30	0.22	0.29	0.29	0
C2H6	0.23	0.23	0.17	0.31	0.08	0.08	0.08	0.08	0.13	0.12	0.13	0.13	0
C3H8	0.14	0.14	0.01	0.25	0	0	0	0	0.09	0.09	0.09	0.09	0
i-C4H10	0.03	0.03	0.00	0.04	0	0	0	0	0.02	0.03	0.02	0.02	0
n-C4H10	0.05	0.05	0.00	0.08	0	0	0	0	0.05	0.06	0.05	0.05	0
i-C5H12	0.01	0.01	0	0.02	0	0	0	0	0.02	0.02	0.02	0.02	0
n-C5H12	0.01	0.01	0	0.03	0	0	0	0	0.03	0.03	0.03	0.03	0
n-C6H14	0.06	0.06	0.00	0.19	0	0	0	0	0.22	0.33	0.22	0.22	0
H2O	0	0	0	0	0	0	0	0	0	0.09	0	0	1.00
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

(d) Overall gas processing plant

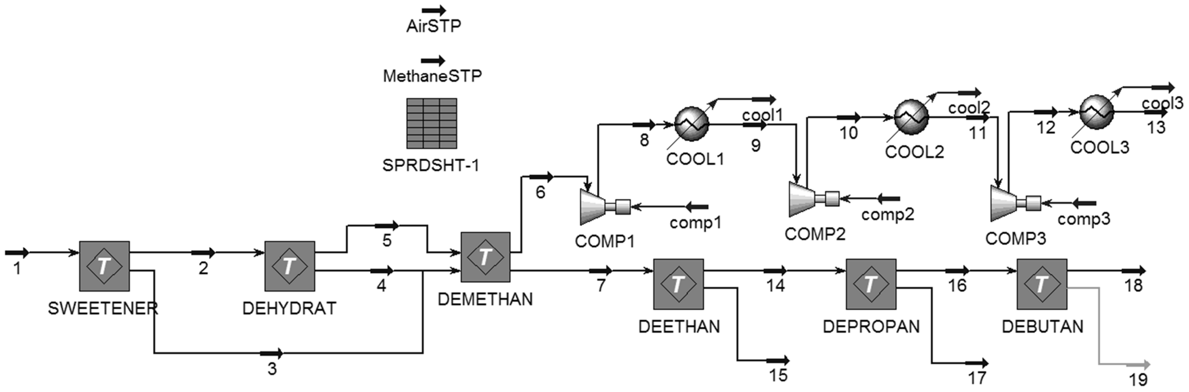

Figure A.20: HYSYS schematic of gas processing plant

Table A.147: Energy table for overall gas processing plant

Name	Energy type	Value (MW)
cool1	Cooling	0.449
cool2	Cooling	0.249
cool3	Cooling	0.123
comp1	Electricity	0.223
comp2	Electricity	0.191
comp3	Electricity	0.171

Table A.148: Mass balance overall gas processing plant

Stream number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Vapour fraction	1.00	1.00	0.07	1.00	0	1.00	0	1.00	1.00	1.00	1.00	1.00	1.00	0	1.00	0	0	0	<empty>
Temperature (°C)	60.0	36.0	24.0	41.5	33.1	69.2	6.88	122.0	25	76.1	25.0	73.1	50.0	99.5	-11.0	114	22.7	141	<empty>
Pressure (kPa)	8100	6860	8100	6170	6200	2060	1550	3500	3470	6000	5970	10000	10000	2000	2000	1000	1000	1000	1000
Molar flow (kmol/hr)	550	420	43.4	419	1	389	74	389	389	389	389	389	389	46.2	27.6	27.5	18.8	20.2	7.27
Mass flow (t/hr)	14.65	8.91	1.96	8.84	0.0568	7.13	3.73	7.13	7.13	7.13	7.13	7.13	7.13	2.87	0.862	2.05	0.821	1.63	0.419
Components (mol%)																			
CH4	0.62	0.77	0.30	0.78	0.22	0.87	0.02	0.87	0.87	0.87	0.87	0.87	0.87	0	0.05	0	0	0	0
C2H6	0.10	0.12	0.13	0.12	0.12	0.08	0.31	0.08	0.08	0.08	0.08	0.08	0.08	0.02	0.81	0	0.05	0	0
C3H8	0.04	0.04	0.09	0.04	0.09	0	0.25	0	0	0	0	0	0	0.39	0.02	0.02	0.92	0.0	0.07
i-C4H10	0.01	0.01	0.02	0.01	0.03	0	0.04	0	0	0	0	0	0	0.07	0	0.10	0.02	0.02	0.34
n-C4H10	0.01	0.01	0.05	0.01	0.06	0	0.08	0	0	0	0	0	0	0.13	0	0.21	0.01	0.09	0.55
i-C5H12	0	0	0.02	0	0.02	0	0.02	0	0	0	0	0	0	0.04	0	0.06	0	0.07	0.02
n-C5H12	0	0	0.03	0	0.03	0	0.03	0	0	0	0	0	0	0.05	0	0.08	0	0.10	0.01
n-C6H14	0.03	0.01	0.22	0.01	0.33	0	0.19	0	0	0	0	0	0	0.31	0	0.52	0	0.71	0
CO2	0.18	0.02	0.15	0.02	0.01	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.12	0	0	0	0
H2O	0	0	0	0	0.09	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N2	0.02	0.02	0.00	0.02	0	0.02	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0	0	0	0	0	0
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Summary of CO_2 calculations

(a) Mass and energy balance

Table A.149: Mass and energy calculations of natural gas and liquid products from raw gas of different compositions

Wellhead gas	Ballera	Timor Sea	Bass strait
Mixed petroleum gas+liquids in (t/h)	1.00	1.00	1.00
Mixed petroleum gas+liquids in (m^3/h)	881	934	1,060
Natural gas out (t/h)	0.484	0.551	0.615
Energy content HHV (GJ/t)	49.3	50.1	53.5
Energy out (GJ/h)	23.9	27.6	32.9
Liquids out (t/h)	0.253	0.356	0.351
Energy content HHV (GJ/t)	47.7	48.7	49.2
Energy out (GJ/h)	12.1	17.3	17.3

(b) CO_2 from acid gas removal

CO_2 removed from raw gas in sweetening unit is taken from HYSYS simulations of gas processing plant.

Table A.150: CO_2 removed from raw natural gas of different compositions

Wellhead gas	Ballera		Timor Sea		Bass strait	
Units	t/h	t/t natural gas product	t/h	t/t natural gas product	t/h	t/t natural gas product
$CO_2$from acid gas removal	0.248	0.512	0.0813	0.148	0.0296	0.0481

(b) CO_2 from on-site power generation

Assume CO_2 is generated from open cycle gas turbines (OCGT).

CO_2 emission factor for OCGT = 0.523 t CO_2/MWh

Table A.151: Calculation of CO_2 produced from on-site power generation using raw gas of different compositions

Wellhead gas	Ballera		Timor Sea		Bass strait	
Units	MWh	MWh/t natural gas product	MWh	MWh/t natural gas product	MWh	MWh/t natural gas product
pump1-1	0.00862	0.0178	0.00376	0.00683	0.00208	0.00339
pump2-1	0.0000784	0.000162	0.0000299	0.0000543	0.0000215	0.000035
comp1	0.0151	0.0313	0.0182	0.0330	0.0240	0.0390
comp2	0.0130	0.0268	0.0153	0.0278	0.0212	0.0345
comp3	0.0116	0.0240	0.0138	0.0250	0.0199	0.0324
Total power required	0.0484	0.100	0.0511	0.0922	0.0672	0.110
Units	t/h	t/t natural gas product	t/h	t/t natural gas product	t/h	t/t natural gas product
CO_2 from gas turbine power generation	0.0253	0.0523	0.0267	0.0482	0.0351	0.0575

(c) CO_2 from flaring

Flaring is modelled by complete combustion of each wellhead gas and calculating the CO_2 product using the following reactions:

Reaction 1: $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$ (Equation A.11)

Reaction 2: $2C_2H_6 + 7O_2 \rightarrow 4CO_2 + 6H_2O$ (Equation A.12)

Reaction 3: $3C_3H_8 + 5O_2 \rightarrow 3CO_2 + 4H_2O$ (Equation A.13)

Reaction 4: $2C_4H_{10} + 13O_2 \rightarrow 8CO_2 + 10H_2O$ (Equation A.14)

Reaction 5: $C_5H_{12} + 8O_2 \rightarrow 5CO_2 + 6H_2O$ (Equation A.15)

Reaction 6: $2C_6H_{14} + 19O_2 \rightarrow 12CO_2 + 14H_2O$ (Equation A.16)

Table A.152: Calculation of CO_2 produced from flaring of raw gas of different compositions

Wellhead gas	Ballera		Timor Sea		Bass strait	
Units	t/h	t/t natural gas product	t/h	t/t natural gas product	t/h	t/t natural gas product
CO_2 from flaring	0.00857	0.0177	0.00959	0.0174	0.0107	0.0177

(d) Total CO_2

Table A.153: Calculation of total CO_2 produced from a gas processing plant using gas of different compositions

Wellhead gas	Ballera		Timor Sea		Bass strait	
Units	t/h	t/t natural gas product	t/h	t/t natural gas product	t/h	t/t natural gas product
Total CO_2	0.281	0.581	0.117	0.212	0.0744	0.121
	t/h	t/t natural gas product	t/h	t/t natural gas product	t/h	t/t natural gas product
CO_2 allocation to natural gas by mass basis	0.185	0.382	0.0713	0.129	0.0475	0.0772
CO_2 allocation to natural gas by energy basis	0.187	0.387	0.0720	0.131	0.0490	0.08

Thus, the range of CO_2 released from the gas processing plant is between 0.0772 to 0.382 t/t natural gas product.

A.80. Data for environmental versus cost graph

Table A.154: Change in GWP impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in GWP impacts	Change in annual costs
		\$mil/yr	t CO_2-e/\$mil	t CO_2-e/yr
Residential	Heating	2,735	-593	-1.62E+06
Mining	Off-grid electricity	5,659	628	3.55E+06
Grid electricity	Peaking	3,264	842	2.75E+06
Manufacturing	Nickel refining	166	3,055	5.08E+05
Manufacturing	Alumina refining	2,872	6,163	1.77E+07
Mining	Heating	89	8,833	7.86E+05
Grid electricity	Baseload	1,982	8,975	1.78E+07
Manufacturing	Chemicals	1,111	13,774	1.53E+07
Total		17,877		5.68E+07

Table A.155: Change in ADP impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in ADP impacts	Change in annual costs
		\$mil/yr	t SO_2-e/\$mil	t SO_2-e/yr
Manufacturing	Alumina refining	2,872	-5	-1.42E+04
Manufacturing	Nickel refining	166	-2	-3.32E+02
Residential	Heating	2,735	4	1.04E+04
Mining	Heating	89	16	1.44E+03
Grid electricity	Baseload	1,982	18	3.50E+04
Mining	Off-grid electricity	5,659	22	1.25E+05
Grid electricity	Peaking	3,264	26	8.54E+04
Manufacturing	Chemicals	1,111	449	4.99E+05
Total		17,877		7.41E+05

Table A.156: Change in POP impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in POP impacts	Change in annual costs
		\$mil/yr	t C_2H_4-e/\$mil	t C_2H_4-e/yr
Manufacturing	Alumina Refining	2,872	-0.77	-2.21E+03
Manufacturing	Chemicals	1,111	-0.54	-5.95E+02
Manufacturing	Nickel Refining	166	-0.29	-4.86E+01
Residential	Heating	2,735	-0.26	-7.12E+02
Grid Electricity	Baseload	1,982	-0.12	-2.32E+02
Mining	Heating	89	0.33	2.95E+01
Mining	Off-grid Electricity	5,659	0.99	5.59E+03
Grid Electricity	Peaking	3,264	2.27	7.39E+03
Total		17,877		9.22E+03

Table A.157: Change in PM_{10} impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in PM_{10} impacts	Change in annual costs
		$mil/yr	t PM_{10}/$mil	t PM_{10}/yr
Manufacturing	Alumina refining	2,872	0.05	1.38E+02
Manufacturing	Nickel refining	166	0.15	2.57E+01
Residential	Heating	2,735	0.25	6.76E+02
Mining	Heating	89	0.79	7.01E+01
Manufacturing	Chemicals	1,111	1.02	1.13E+03
Grid electricity	Peaking	3,264	2.13	6.94E+03
Mining	Off-grid electricity	5,659	2.17	1.23E+04
Grid electricity	Baseload	1,982	2.25	4.46E+03
Total		17,877		2.57E+04

Table A.158: Change in FWW impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in FWW impacts	Change in annual costs
		$mil/yr	t FWW/$mil	t FWW/yr
Manufacturing	Alumina refining	2,872	-1189.78	-3.42E+06
Mining	Heating	89	-621.92	-5.53E+04
Grid electricity	Peaking	3,264	-101.29	-3.31E+05
Mining	Off-grid electricity	5,659	-87.99	-4.98E+05
Residential	Heating	2,735	7973.27	2.18E+07
Manufacturing	Nickel refining	166	14815.78	2.46E+06
Manufacturing	Chemicals	1,111	19232.95	2.14E+07
Grid electricity	Baseload	1,982	24457.04	4.85E+07
Total		17,877		8.98E+07

Table A.159: Change in AWW impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in AWW impacts	Change in annual costs
		$mil/yr	t AWW/$mil	t AWW/yr
Manufacturing	Chemicals	1,111	-904.18	-1.00E+06
Grid Electricity	Baseload	1,982	-842.97	-1.67E+06
Manufacturing	Alumina Refining	2,872	-568.98	-1.63E+06
Residential	Heating	2,735	-326.81	-8.94E+05
Manufacturing	Nickel Refining	166	-261.62	-4.35E+04
Mining	Off-grid Electricity	5,659	117.75	6.66E+05
Grid Electricity	Peaking	3,264	135.56	4.42E+05
Mining	Heating	89	832.29	7.40E+04
Total		17,877		-4.06E+06

Table A.160: Change in SWD impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in SWD impacts	Change in annual costs
		$mil/yr	t SWD/$mil	t SWD/yr
Manufacturing	Alumina Refining	2,872	-216.82	-6.23E+05
Mining	Off-grid Electricity	5,659	0.28	1.56E+03
Grid Electricity	Peaking	3,264	0.32	1.03E+03
Mining	Heating	89	1.95	1.73E+02
Residential	Heating	2,735	1,162.76	3.18E+06
Manufacturing	Chemicals	1,111	1,419.01	1.58E+06
Grid Electricity	Baseload	1,982	1,980.19	3.93E+06
Manufacturing	Nickel Refining	166	13,852.79	-6.23E+05
Total		17,877		1.04E+07

Table A.161: Change in SWG impacts versus change in total operating costs

Sector	Component	Change in total operating costs	Change in SWG impacts	Change in annual costs
		$mil/yr	t SWG/$mil	t SWD/yr
Mining	Off-grid Electricity	5,659	2.03	1.15E+04
Grid Electricity	Peaking	3,264	2.34	7.64E+03
Mining	Heating	89	14.37	1.28E+03
Manufacturing	Nickel Refining	166	10,236.54	1.70E+06
Residential	Heating	2,735	12,529.98	3.43E+07
Manufacturing	Alumina Refining	2,872	22,397.10	6.43E+07
Grid Electricity	Baseload	1,982	33,213.58	6.58E+07
Manufacturing	Chemicals	1,111	42,758.92	4.75E+07
Total		17,877		2.14E+08

A.81. The CML 1992 method

Heijungs et al. (1992) calculated a dimensionless abiotic depletion score using Equation A.17. Material use for each raw material was obtained from LCI and the reserves of each raw material were obtained from World Resources Institute (1990-1991). Both material use and reserves are in units of kg of raw material. Heijungs et al. (1992) only included raw materials on the basis that their recoverable reserves may become insufficient within 100 years. For energy carriers, only crude oil, natural gas and uranium were selected. Coal was not considered as a resource that may become insufficient within 100 years and was therefore excluded.

$$\text{Abiotic depletion} = \sum_i \frac{\text{Material use}_i}{\text{Reserves}_i} \qquad (\text{Equation A.17})$$

For this study, the material use is replaced with the amount of resource extracted per unit product (e.g. t/MWh or t/GJ_{heat}). Reserves for natural gas and coal are taken from 2013 data in the BP Statistical Review of World Energy 2014. Australia data was chosen over world data so that the calculated abiotic depletion indicators were normalised to the Australian resource depletion situation. The calculated results are shown in Table A.162.

Table A.162: Calculations to obtain abiotic depletion indicators using the CML 1992 method for grid electricity generation and residential heating using different feedstock

	Baseload Grid Electricity			Peaking Grid Electricity			Residential Heating		
	Unit	Natural gas case	Black coal case	Unit	Natural gas case	Diesel case	Unit	Natural gas case	Black coal case [a]
Resource *i* extracted per unit product, y_i	t/MWh	0.136	0.363	t/MWh	0.199	0.209	t/GJ_{heat}	0.0240	0.0295
Reserves of resource *i*, Re_i [a]	t	2.80×10^9 (3.7×10^{12} m^3)[b]	7.64×10^{10} [c]	t	2.80×10^9 (3.7×10^{12} m^3)[b]	5.46×10^8 (4.0×10^9 barrels)[d]	t	2.80×10^9 (3.7×10^{12} m^3)[b]	7.64×10^{10} [c]
Final indicator	/MWh	4.86×10^{-11}	4.75×10^{-12}	/MWh	7.12×10^{-11}	3.83×10^{-10}	/GJ_{heat}	8.57×10^{-12}	3.86×10^{-13}

[a] 'Reserves' refer to world reserves of natural gas, coal and crude oil taken from BP (2014).

[b] Density of natural gas = 0.7579 kg/m^3 (AGO 2006).

[c] Includes anthracite, bituminous, sub-bituminous and lignite coal.

[d] To convert barrels to tonnes, multiply by 0.1364.

A.82. <u>The CML 2001 method</u>

Guinée et al. (2001) used a different ADP for fossil energy carriers from the 1992 version because fossil energy carriers were assumed to be “full substitutes (both as energy carriers and as materials)” and can be substituted with one another. Hence, the ADPs for fossil energy carriers should be the same in terms of total energy reserve. An overall fossil energy ADP was calculated with based on the reserves (R) and de-accumulation (DR) of both the total fossil energy and the reference resource Antimony (Sb) as shown in Equation A.18.

$$ADP_{fossilenergy} = \frac{DR_{fossilenergy}}{\left(R_{fossilenergy}\right)^2} \times \frac{\left(R_{antimony}\right)^2}{DR_{antimony}} \qquad (\text{ Equation A.18 })$$

R and DR represent the ultimate global reserve and global annual extraction rate respectively for fossil energy and antimony. The proven global reserve and global annual extraction rate of fossil energy (3.46x10^{16} MJ and 3.03x10^{14} MJ/yr respectively) were obtained from World Resources Institute (1994-1995) and included coal, oil and gas. The ultimate global reserve can be calculated by multiplying the proven global reserve by 1.36x10^{4} (ratio of fossil carbon content of the earth’s crust to carbon content of proven reserves of fossil energy fuels). The reserves were squared to avoid situations where two different resources had similar ADP scores, but in reality had vastly different magnitudes in the share of the reserves. The power of 2 was arbitrarily chosen and heuristically derived (Guinée & Heijungs 1995).

The ADP for 1 MJ of fossil energy is calculated to be:

$$ADP_{fossilenergy} = \frac{3.03\times10^{14}\ MJ/yr}{\left(4.72\times10^{20}\ MJ\right)^2} \times \frac{\left(4.63\times10^{12}\ t\right)^2}{6.06\times10^{4}\ t/yr} = 4.81\times10^{-7}\ t\ Sb-eq./MJ$$

The ADP for natural gas and black coal (termed hard coal in the literature) is then calculated by multiplying the ADP for fossil energy with their respective higher heating values (HHV) found in Guinée et al. (2001).

$$ADP_{gas} = ADP_{fossilenergy} \times HHV_{gas} = 4.81\times10^{-7}\ t\ Sb-eq./MJ \times 52{,}225\ MJ/t$$

$$ADP_{gas} = 0.0251\ t\ Sb-eq./t\ natural\ \ gas\ extracted$$

$$ADP_{hardcoal} = ADP_{fossilenergy} \times HHV_{hardcoal} = 4.81\times10^{-4}\ t\ Sb-eq./MJ \times 23{,}968\ MJ/t$$

$$ADP_{hardcoal} = 0.0115 t\ Sb-eq./t\ black\ coal\ extracted$$

$$ADP_{oil} = ADP_{fossilenergy} \times HHV_{oil} = 4.81\times10^{-4}\ t\ Sb-eq./MJ \times 45.6\ MJ/t$$

$$ADP_{oil} = 0.0219 t\ Sb-eq./t\ \text{oil}\ extracted$$

The ADP for grid electricity generation and ammonia production is calculated based on the feedstock used as shown in Table A.163.

Table A.163: Calculations to obtain abiotic depletion indicators using the CML 2001 method for grid electricity generation and residential heating using different feedstock

	Baseload Grid Electricity			Peaking Grid Electricity			Residential Heating		
	Unit	Natural gas case	Black coal case	Unit	Natural gas case	Diesel case	Unit	Natural gas case	Black coal case
Resource *i* extracted per unit product, y_i	t/MWh	0.136	0.363	t/MWh	0.199	0.209	t/GJ_{heat}	0.0240	0.0295
ADP	t Sb-eq./t resource extracted	$2.51x10^{-2}$	$1.15x10^{-2}$	t Sb-eq./t resource extracted	$2.51x10^{-2}$	$2.19x10^{-2}$	t Sb-eq./t resource extracted	$2.51x10^{-2}$	$1.15x10^{-2}$
Final indicator	t Sb-eq./MWh	$3.41x10^{-3}$	$4.17x10^{-3}$	t Sb-eq./MWh	$4.99x10^{-3}$	$4.58x10^{-3}$	t Sb-eq./GJ_{heat}	$6.02x10^{-4}$	$3.39x10^{-4}$

A.83. Resource Depletion Index (RDI)

Lee (1998) uses a similar ‘reserves-de-accumulation ratio’ as developed by Guinée & Heijungs (1995) to evaluate the sufficiency of reserves. The Resource Depletion Index (RDI) is shown in Equation A.19.

$$RDI = \frac{\text{Global reserve}}{\text{Annual production rate}} = \text{Maximum extractable years} \qquad (\text{Equation A.19})$$

The RDI shows the maximum number of years for which current reserves will suffice at the current annual de-accumulation or production level. There are indicators that resemble the RDI, such as the the Re/Pr indicators shown in Table A.164 which measure the remaining years of extraction for both world and Australian data.

Table A.164: Re/Pr indicators for natural gas, black coal and oil using data from the BP Statistical Review of World Energy (2014)

Resource	Australia (2013)			World (2013)		
	Reserves, Re (t)	Production, Pr (t/yr)	Re/Pr (yrs)	Reserves, Re (t)	Production, Pr (t/yr)	Re/Pr (yrs)
Natural gas [a]	2.80×10^{9} (3.7×10^{12} m^3)	3.25×10^{7} (4.29×10^{10} m^3)	86.2	1.41×10^{11} (1.86×10^{14} m^3)	2.55×10^{9} (3.37×10^{12} m^3)	55.3
Coal [b]	7.64×10^{10}	4.78×10^{8}	160	8.92×10^{11}	7.90×10^{9}	113
Oil [c]	5.46×10^{8} (4.0×10^{9} barrels)	1.79×10^{7}	30.5	2.31×10^{11} (1.69×10^{12} barrels)	4.13×10^{9}	55.9

[a] Density of natural gas = 0.7579 kg/m^3 (AGO 2006).

[b] Includes anthracite, bituminous, sub-bituminous and lignite coal.

[c] To convert barrels to tonnes, multiply by 0.1364.

This methodology can be applied to LCA by multiplying the inverse of the Re/Pr indicators with the quantity of resource required to produce a functional unit of product. The results are shown in Table A.165. The more recent Australian data from the BP Statistical Review of World Energy (2014) was used. High values of RDI indicate greater resource extraction within a year for every unit of product.

Table A.165: Calculations to obtain abiotic depletion indicators for grid electricity generation and residential heating using different feedstock

	Baseload Grid Electricity			Peaking Grid Electricity			Residential Heating		
	Unit	Natural gas case	Black coal case	Unit	Natural gas case	Diesel case	Unit	Natural gas case	Black coal case
Resource *i* extracted per unit product, y_i	t/MWh	0.136	0.363	t/MWh	0.199	0.209	t/GJ_{heat}	0.0240	0.0295
Re/Pr	yrs	86.2	160	yrs	86.2	30.5	yrs	86.2	160
Final indicator	t/MWh.yr	1.58×10^{-3}	2.27×10^{-3}	t/MWh.yr	2.31×10^{-3}	6.85×10^{-3}	t/GJ_{heat}.yr	2.78×10^{-4}	1.84×10^{-4}

A.84. The Eco-Indicator 99 method

The Eco-Indicator 99 method by Goedkoop & Spriensma (2001) measures resource depletion with a 'damages to resources' endpoint indicator. A damage of 1 means that a certain further extraction of this resource in the future will require an additional 1 MJ of surplus energy due to factors such as lower resource concentration. The point in the future has been arbitrarily chosen as the time at which 5 times the cumulative extraction of the resource before 1990 is extracted.

End-point indicators have a large degree of uncertainty. The Eco-Indicator 99 method addresses this issue by assuming different perspectives or value systems from the Cultural Theory to predict basic attitudes and assumptions for its damage models. For fossil fuels, these three perspectives determine the fuel mix that will replace current fuels in the future, as this affects the amount of surplus energy required for further extraction. The hierarchist assumes no interchangability, that is, fossil fuels are not simply interchangeable with one another to provide energy. Current fossil fuels are used up, and then replaced with a resource of similar properties in the future. For example, when natural gas is depleted, it must be replaced with an unconventional source of gas or oil, and for black coal, this is replaced with brown coal. For the egalitarian perspective, interchangability was assumed and all energy in the future is derived from a single energy mix, which is a combination of coal and shale. There was no damage model for fossil fuels for the individualist perspective as they do not view resource depletion as a serious problem.

Table A.166: Assumed fossil fuels that will replace the current fuels for the three perspectives

Archetypes Current fuel	Hierarchist	Egalitarian	Individualist
Conventional natural gas	Oil shale	Coal-shale mix	Conventional gas
Hard coal, open pit mining	Brown coal	Coal-shale mix	Hard coal, open pit
Conventional oil	Oil shale	Coal-shale mix	Conventional oil

The surplus energy can now be calculated by subtracting the current energy requirement for a fuel from the energy requirement for the future fuel or mix selection. The outcomes of the damage models are summarised in Table A.167 for the hierarchist perspective and Table A.168 for the egalitarian perspective.

Table A.167: Calculation of damage to resources for grid electricity generation and residential heating using different feedstock according to the hierarchist perspective in Eco-Indicator 99

	Baseload Grid Electricity			Peaking Grid Electricity			Residential heating		
	Unit	Natural gas case	Black coal case	Unit	Natural gas case	Diesel case	Unit	Natural gas case	Black coal case
Resource *i* extracted per unit product, y_i	t/MWh	0.136	0.363	t/MWh	0.199	0.209	t/GJ_{heat}	0.0240	0.0295
Damage factor	MJ surplus energy/t resource extracted	4,550	252	MJ surplus energy/t resource extracted	4,550	5,900	MJ surplus energy/t resource extracted	4,550	252
Damage to resources	MJ surplus energy/MWh	619	91.5	MJ surplus energy/MWh	905	1,230	MJ surplus energy/ GJ_{heat}	109	7.43

Table A.168: Calculation of damage to resources for grid electricity generation and residential heating using different feedstock according to the egalitarian perspective in Eco-Indicator 99

	Baseload Grid Electricity			Peaking Grid Electricity			Residential heating		
	Unit	Natural gas case	Black coal case	Unit	Natural gas case	Diesel case	Unit	Natural gas case	Black coal case
Resource *i* extracted per unit product, y_i	t/MWh	0.136	0.363	t/MWh	0.199	0.209	t/GJ_{heat}	0.0240	0.0295
Damage factor	MJ surplus energy/t resource extracted	2,700	2,040	MJ surplus energy/t resource extracted	2,700	3,400	MJ surplus energy/t resource extracted	2,700	2,040
Damage to resources	MJ surplus energy/MWh	367	741	MJ surplus energy/MWh	537	711	MJ surplus energy/ GJ_{heat}	64.8	60.2

A.85. The ReCiPe 2008 method

The ReCiPe 2008 method proposed by Goedkoop et al. (2009) addresses damage to resources as the additional environmental costs society has to pay as a result of an extraction, which is calculated using Equation A.20. All monetary terms in the ReCiPe method are expressed in 2004 US dollars.

$$\text{Damage to resources} = \left(CF_{end}\right)_i \times \Delta x_{ij} \qquad (\text{Equation A.20})$$

where $(CF_{end})_i$ = endpoint characterisation factor for extraction of fossil fuel *i*

Δx_{ij} = extracted mass that caused the price increase (t)

The characterisation factor (CF) is calculated using Equation A.21.

$$\left(CF_{end}\right)_i = \frac{\Delta C}{\Delta x_{ij}} \times \Pr \times NPV_T = MCI \times \Pr \times NPV_T \qquad (\text{Equation A.21})$$

where ΔC = environmental cost increase (\$/t)

MCI = marginal cost increase (\$/t^2)

Pr = produced amount of resource over a certain period (t.year^{-1})

NPV_T = net present value factor of spending a dollar a year over a time *T* (years)

Under the fossil fuel category, the reference resource chosen by the authors was ‘oil, crude, feedstock, 42,000 MJ per t, in ground’. According to the authors, for oil resources up to 3000 gigabarrels, the price of oil needs to go up by 10 dollars per barrel for every 1000 gigabarrel production of oil. For the next 1000 gigabarrel after 3000 gigabarrels, the price will need to increase 30 dollars per 1000 gigabarrel or more. Equation A.21 is then expressed per tonne of oil, with MCI producing a value of 6.4×10^{-8} \$/t^2 for a production of up to 3000 gigabarrels, and 1.4×10^{-7} \$/t^2 after 3000 gigabarrels have been produced. *Pr* then becomes the annual production of oil in a base year, and 3.43×10^{9} t was used based on 2000 data.

The ReCiPe 2008 method utilises the Cultural Theory perspectives to decide which marginal price increase will be used.

- The individualist perspective assumes free market forces and quick development of technology to solve many problems. Their perception of time adheres to the short term, hence the marginal price increase for up to a production volume of 3000 Gb is used (6.4×10^{-8} \$/t^2). This then produces an endpoint factor $(CF_{end})_{oil}$ of \$7,280/t oil-eq.
- The hierarchist perspective perceives time over the long term, hence the marginal price increase after 3000 Gb of 1.4×10^{-7} \$/t^2 has been exploited. This then produces an endpoint factor $(CF_{end})_{oil}$ of \$16,070/t oil-eq.
- The egalitarian perspective have views in line with the Peak Oil movement, however the authors were unable to link a scenario to the egalitarian perspective, hence the same model as

applied to the hierarchist perspective is used for the egalitarian perspective, giving an endpoint factor $(CF_{end})_{oil}$ of \$16,070/t oil-eq.

The endpoint characterisation factor for oil $(CF_{end})_{oil}$ is multiplied by the midpoint characterisation factor for depletion of resource *i* $(CF_{mid})_i$ to obtain an endpoint characterisation factor for resource *i* $(CF_{end})_I$ as shown in Equation A.22.

$$(CF_{end})_i = (CF_{mid})_i \times (CF_{end})_{oil} \qquad \text{(Equation A.22)}$$

The ReCiPe method lists the midpoint characterisation factors $(CF_{mid})_i$ of natural gas to be 9.12x10^{-4} t oil-eq./m^3 or 1.17 t oil-eq./t for a natural gas density of 7.77x10^{-4} t/m^3, $(CF_{mid})_i$ for hard coal is 0.455 t oil-eq./t, and $(CF_{mid})_i$ for crude oil is 1.09 t oil-eq./t.

Table A.169: Calculation of damage to resources for grid electricity generation and residential heating using different feedstock according to the individualist perspective in ReCiPe 2008

	Baseload Grid Electricity			Peaking Grid Electricity			Residential heating		
	Unit	Natural gas case	Black coal case	Unit	Natural gas case	Diesel case	Unit	Natural gas case	Black coal case
Resource *i* extracted per unit product, y_i	t/MWh	0.136	0.363	t/MWh	0.199	0.209	t/GJ$_{heat}$	0.0240	0.0295
$(CF_{end})_i$	\$x1000/t	8.52	3.31	\$x1000/t	8.52	7.94	\$x1000/t	8.52	3.31
Damage to resources	\$1000/MWh	1.16	1.20	\$1000/MWh	1.70	1.66	\$1000/GJ$_{heat}$	0.204	0.0976

Table A.170: Calculation of damage to resources for grid electricity generation and residential heating using different feedstock according to the hierarchist and egalitarian perspective in ReCiPe 2008

	Baseload Grid Electricity			Peaking Grid Electricity			Residential heating		
	Unit	Natural gas case	Black coal case	Unit	Natural gas case	Diesel case	Unit	Natural gas case	Black coal case
Resource *i* extracted per unit product, y_i	t/MWh	0.136	0.363	t/MWh	0.199	0.209	t/GJ$_{heat}$	0.0240	0.0295
$(CF_{end})_i$	\$x1000/t	18.8	7.31	\$x1000/t	18.8	17.5	\$x1000/t	18.8	7.31
Damage to resources	\$1000/MWh	2.56	2.65	\$1000/MWh	3.74	3.66	\$1000/GJ$_{heat}$	0.451	0.216

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