




Potential Chemical and Energy Uses for Lignite at Hawkdun and Ashers-Waituna, New Zealand

**Study Report
prepared for
Kenham Holdings Limited**

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Contents

- Executive Summary 3**

- 1 Introduction 5**

- 2 Definition of the Lignite Resources 5**

- 3 Lignite Mining Assessment 7**

- 4 Comparison of Conversion Routes 9**
 - 4.1 Background 9
 - 4.2 IGCC versus Supercritical Power Generation 10
 - 4.3 Economics 10

- 5 Production of Chemicals and Fuels from Synthesis Gas 13**

- 6 International Trends for Gasification 15**

- 7 Energy Markets 17**
 - 7.1 Electricity 17
 - 7.2 Fuel Gas 17
 - 7.3 New Industrial Market 18

- 8 Capture and Disposal of CO₂ 18**

- 9 Conclusions and Recommendations 19**

- 10 References /Bibliography 21**

- Appendix 1: Review of Gasification Technology 25**

- Appendix 2: Selected Lignite Deposit Characteristics 45**

- Appendix 3: Carbon Capture and Sequestration 61**

Executive Summary

This preliminary study brings together publically available information and work from earlier studies of the South Island Lignite resources in order to examine the potential value of the lignite deposits held by Kenham holdings to meet New Zealand's emerging demand for primary energy.

Kenham holds extensive energy resources in Otago and Southland. The estimated reserves of 872 million tonnes from Ashers-Waituna and 475 million tonnes from the Hawkdun deposit are more than sufficient to support a major coal conversion facility.

There are basically three energy markets available to a lignite conversion plant in the Otago/Southland region; electricity to the New Zealand electricity market, fuel gas to meet local energy needs, or the direct supply of electricity, heat or synthesis gas to a new industry.

Of the options considered, the conversion of coal to synthesis gas via gasification and subsequent conversional to Ammonia/Urea offers the most attractive immediate development option. This, integrated with a Combined Cycle (IGCC) power plant, provides the most likely potential economic opportunity in the near term.

Preliminary economic estimates for electricity and synthesis gas production indicate that synthesis gas can be produced for about \$6.95/GJ and electricity from an associated IGCC plant for \$0.05/kWh.

Recommendations

- Coal gasification is the preferred option for conversion of the Southland lignite to meet New Zealand's future energy needs. Gasification offers proven technology and the cost basis can be established with confidence.
- In the near- to medium-term the production of synthesis gas for conversion to petrochemicals is seen as a potentially viable option. The most attractive product currently appears to be Ammonia for fertiliser manufacture.
- There is potential in the near-term for a smaller scale facility to supply power to the aluminium industry in Southland during dry years when hydroelectric power is not available. Underwriting of such a venture could be available via Government's dry-year reserve provisions.
- Primary focus should be given to the use of the lignites to meet future chemical and fuels supply needs, with electricity generation treated as a by-product of the process to attain improved economies of scale.

Further study work should be conducted. This should include improved definition of the coal properties and detailed study of the economics of production for the various petrochemical/fuels options. Electricity generation for support of local industry during dry years should be investigated as a matter of priority.

1 Introduction

Kenham Holdings currently holds permits over several lignite deposits in Central Otago and Southland. Based on the deposits at Hawkdun and Ashers-Waituna, this report examines the potential uses of the lignite as a feedstock for both generation of electricity, and conversion to gas and petrochemicals.

This work brings together publicly available information and work from earlier studies of the lignite resources. Possible conversion process technologies have been evaluated, including economic aspects, and greenhouse gas management strategies briefly explored. Energy markets have also been considered to bring together an overview of the potential value of the resources as a feedstock to meet New Zealand's emerging demand for primary energy.

2 Definition of the Lignite Resources

Investigations of South Island lignites extend over a period of some 50 years. In the 1950's shallow boreholes were drilled in east Southland. Between 1976 and 1979 the Ministry of Energy included the lignites in its "NZ Coal Resources Survey", which included an extensive drilling programme. From this work, several major deposits were identified, including Hawkdun and Ashers-Waituna.

In the early 1980's, the NZ Government established the Liquid Fuels Trust Board (LFTB), which investigated the South Island lignites as a source of transport fuel. The work included deposit geology, resource and reserve estimates, mining assessments, lignite quality, conversion methods, infrastructural requirements, and environmental issues, described in various reports¹⁻⁹. In addition, LFTB selected three deposits for more detailed investigation, two of which were Hawkdun and Ashers-Waituna¹⁰⁻¹⁶.

Information from the overall summary LFTB report¹⁷ relevant to this study of Hawkdun and Ashers-Waituna is included essentially verbatim (see Appendix II); key data on lignite quantity and quality are given in Table 1. Reserve data are Technically Recoverable Reserves as defined by Dr Otto Gold Consulting, which excludes lignites present in insufficiently investigated areas and lignite considered to be economically unrecoverable as well as losses during mining from slope angles, etc. Other LFTB general reports are also available¹⁸⁻²⁴.

	Ashers-Waituna	Hawkdun
Reserves (million tonnes)	872	475
Specific Energy (MJ/kg)	11.31	10.48
Moisture (% , in situ)	54.9	47.9
Ash (% , bed moisture basis)	4.9	9.5
No. Boreholes analysed (seams)	13 (5)	2 (5)

Table 1: Lignite Quantity and Quality (from reference 17)

Kenham has initiated further investigations of the characteristics and mining potential of the Hawkdun and Ashers-Waituna resources, oriented towards use for power generation²⁵⁻²⁸. In the context of this study, the findings of these recent investigations are generally consistent with those of the LFTB

3 Lignite Mining Assessment

Summary information from LFTB mining assessment work¹⁷ is given in Table 2. These investigations indicated production costs of NZ\$7/t and NZ\$6.6/t at 10 million tonnes/annum for Hawkdun and Ashers - Waituna respectively. For this study, two production costs have been assumed, NZ\$5/t and NZ\$10/t both on an as-mined basis.

With a specific energy of the delivered coal assumed to be in the range 11-12 GJ/Tonne the resulting energy cost is thus likely to be less than US\$ 50c/GJ, making these resources amongst the most competitive energy resources available worldwide³³. Stripping ratios for the two deposits average approximately 2.1 for the Hawkdun deposit and 2.4 for Ashers-Waituna.

	Production Rate Mt/a	Average Ash %	Recovery %
Hawkdun	2.5	8.9	16
	9.5	8.2	60
	12.5	8.4	79
	15.0	8.4	95
Ashers- Waituna	10.0	6.6	34
	15.0	6.9	52
	20.0	7.2	69

*Table 2: Summary Mining Information (Life cycle 30 years)
(from reference 17)*

4 Comparison of Conversion Routes

4.1 Background

Coal can be readily converted to electrical energy or gaseous products via a number of methods. The combustion of coal for electricity production is standard technology worldwide. There are no special issues that would suggest anything but standard application for NZ.

Gasification is a commercially proven technology and involves the partial oxidation of various feedstocks (gases, liquids or solids) to clean synthesis gas (syngas), which is basically a mixture of hydrogen, carbon monoxide, some carbon dioxide and a little methane. The hot syngas is cooled and purified using technologies common to natural gas purification and oil refining. Syngas can then be used for the manufacture of liquid fuels, chemicals and/or electricity, as shown in Figure 1.

It is not suggested that all the routes shown would be economically feasible, but as oil prices increase and the world's supply of cheap natural gas and crude oil decline then coal conversion via gasification offers an alternative route to these important chemical intermediaries. A more detailed description of coal gasification technology and current development status is provided in Appendix I.

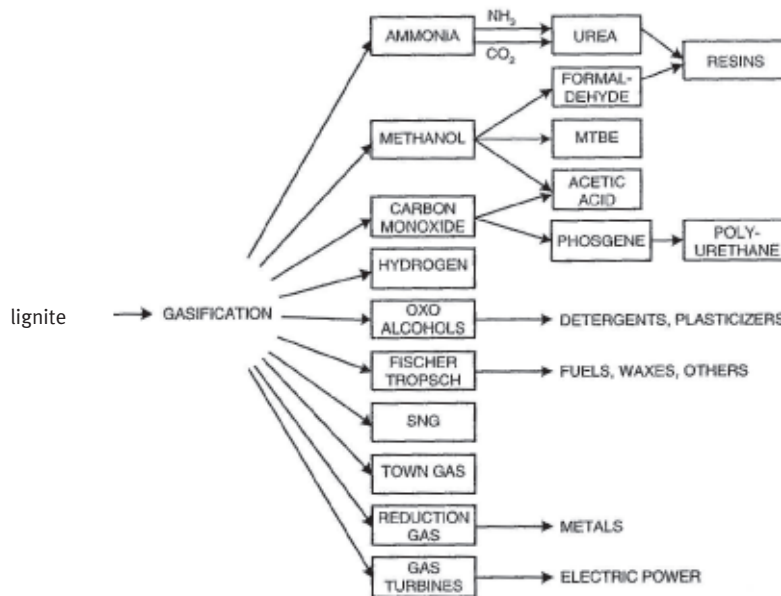


Figure 1 : Products obtainable from synthesis gas²⁹

The optimal utilisation of the lignites will ultimately be dependent on the timing of current technological advances in conversion technologies, preferred commercial scale and future market demand for primary fuels. There is a considerable worldwide effort to develop, demonstrate and commercialise new high efficiency advanced coal-based power generation technologies, which have the potential to create significant additional economic value. Whilst currently the commercial availability and scale of these technologies are generally limited by financing issues around technological risk, as well as minimum unit capacities as set by international manufacturing capability³⁰, this situation is expected to change rapidly over the next several years.

Accordingly, it is the CAE view that short-term development of the lignite deposits based on conventional electricity generation is unlikely to offer the most economic use of the resource and instead focus should be given to the medium to long term. The study thus considers two emerging modern conversion routes:

- Pulverized Coal-fired Supercritical Steam Cycle (PC)
- Integrated Gasification Combined Cycle (IGCC)

Supercritical power generation describes the thermodynamic state of the steam raised by the boiler used in the steam turbine of a power station. Whilst currently limited to plant greater than 400MW unit size these plants offer greatly improved efficiency over conventional Rankine cycle subcritical plant.

IGCC systems also offer the prospects of higher efficiencies and reduced environmental impacts than conventional pulverised fuel power plant. Because they produce a clean syngas these plants also lend themselves to poly generation projects. A significant barrier to the uptake of the technology is that the plants require chemical or process engineering expertise - which is totally lacking in most electricity utilities³¹. Close integration offers better efficiencies but more complexity. This is an important trade-off.

4.2 IGCC versus Supercritical Power Generation

There are two major issues facing development of the South Island Lignite;

1. The deposits are too far away from major load centres to make a significant contribution to the county's electricity supply without another major DC link addition, with regional load growth unlikely to support a significant additional supply without investment in a matching new load.
2. CO₂ disposal has to be addressed, particularly considering that the CO₂ cost of electricity from lignite is about 1 tonne CO₂ per MWh, and that NZ has signalled its intention to implement a carbon tax from 2007 onwards.

Review of the two technology routes highlights the following advantages of IGCC over PC when taking these factors into account:

(a) IGCC has a much lower life cycle cost when CO₂ capture is included.

Modern gasification is a high pressure process which uses oxygen and steam to convert the feedstock, so the CO₂ produced is undiluted by atmospheric nitrogen and therefore its capture is less costly. For IGCC the predicted add-on cost of capture equipment is around 5 % of capital cost, whilst for PC it is at least 60 % of capital cost²⁹. Further, PC requires compression of the CO₂ before storage, which we estimate would increase operational and maintenance cost by about 2.6 % of capital cost per annum. (note: subsequent CO₂ storage or disposal costs have not been considered in this study).

(b) IGCC is better suited to low rank coals such as lignite.

Supercritical design and operation is more sensitive to coal characteristics especially water content and ash slagging behaviour. Whilst we do not have access to any specific gasification tests for the lignites under consideration, the published literature for similar coal-types would suggest the deposits will be well-suited to gasification processes.

(c) IGCC allows polygeneration offering more revenue options.

Polygeneration refers to the range of simultaneous manufacturing options that are possible downstream of gasification (see Figure 1).

4.3 Economics

The following summarises preliminary economic estimates based on an assumed thirty years life cycle for both the IGCC and PC options. For the purposes of this comparison CO₂ capture cost is included in the estimates with allowance also made for the assumed additional cost for CO₂ compression to 30 bar (equates with IGCC) in the case of the PC plant. The costs for CO shift (which is the conversion of CO to CO₂ and H₂ so as to increase hydrogen content of the syngas) and any subsequent CO₂ sequestration costs have not been included in these economics.

Equipment cost for the CO shift step in the case of IGCC is not expected to be major and will not influence the overall economics reported in this study. Conversely the equipment and O & M costs for CO₂ sequestration are significant and depend heavily on the location of a suitable storage zone deep underground.

CO₂ associated cost estimates used are listed below, expressed as percentage of overall plant capital

cost. These estimates are indicative only, based on the costs reported in the published literature, and will require engineering confirmation.

IGCC capture investment – 5 % add on.

No increase in O & M cost which remains at 5.0 % of investment cost.

Supercritical capture investment – 60 % add on.

Compression increases O & M cost from 3.0 % to 5.6 % of investment.

Table 3 summarises the specific capital costs used for three sizes of plant and both options considered. Results of the life cycle costing calculations indicate that the IGCC plant yields prices that are realistic for both electricity and gas over the range of conditions examined. Specific economic assumptions used in development of the selling price were as follows;

- Assumed plant availabilities and efficiencies are as given in Table 4.
- Operating capital is assumed to be 10 %, subtracted year 0 and added year 30.
- Construction period 3 years, 50 percent production in year 1. Venture costs prior to commencement of construction have not been taken into account.
- NZ/US exchange rate 0.6.
- Average feed specific heat 10GJ/tonnes as delivered (assumed approximately 60 percent water as a feed basis to the gasifier plant to yield a suitable feed material).

Capacity MW _e	Capital cost US\$/kW including provision for CO ₂ separation	
	IGCC	Supercritical
250	1365	1920
400	1260	1728
800	1155	1584

Table 3: Capital cost estimation basis

	Plant availability	Electrical efficiency	Gas efficiency	Construction time (years)
IGCC	92 %	40 %	80 %	3
Supercritical	95 %	40 %	-----	3

Table 4: Assumed plant configurations

Capacity MW _e	Electricity price NZc/kWh				Gas price NZ\$/GJ	
	IGCC		Supercritical			
250	5.83	6.28	8.01	8.46	8.10	8.73
400	5.42	5.87	7.25	7.70	7.52	8.15
800	5.00	5.45	6.69	7.14	6.95	7.57

Table 5: Estimated energy prices for electricity or syngas to achieve required 8% IRR (lignite feed delivered at \$NZ 5/tonne and \$NZ 10/tonne)

5 Production of Chemicals and Fuels from Synthesis Gas

An important consideration in determining downstream application is the composition of the syngas and overall efficiency of the gasification process selected. Because of the limited nature of this analysis it is not possible to be precise in this respect – to do so would require significant process engineering study and gasification trials.

However, based on published information^{29, 32} a preliminary mass balance suggests that using the Texaco process the composition of raw synthesis gas (mol %) from either Hawkdun or Ashers-Waituna lignites is expected to be approximately:

H ₂	CO	CO ₂	A	N ₂	H ₂ S
33.3	57.6	6.3	0.6	1.0	0.2

The predicted H₂/CO ratio 0.58 for the derived synthesis gas will require adjustment and further processing to suit particular applications for any subsequent downstream chemical/fuel production. This can be accomplished by the CO shift reaction followed by CO₂ removal, both well-proven petrochemical refinery technologies. Table 6 lists typical stoichiometric ratios required for some NZ relevant products.

Product	Stoichiometric Ratio (SR)	SR Value
Raw syngas	H ₂ /CO*	0.58
Ammonia	H ₂ /N ₂	3.0
Urea	NH ₃ /CO ₂	2.0
Methanol	H ₂ /CO	2.5
SNG	H ₂ /(3CO+4CO ₂)	0.98 – 1.03

Table 6: Gas Stoichiometry

* not stoichiometric - estimated syngas composition

Preliminary mass and heat balances derived for the two coals fields indicate that a 500 MW_{th} IGCC plant (or ~250 MW_e, stand-alone power plant) plant would consume around 1.87 million tonnes/annum of lignite (10 GJ/t) and would be capable of supporting the downstream applications shown in Table 7. The quantities shown apply to single application only, except for urea, which is manufactured from reacting ammonia and carbon dioxide.

Ammonia	Urea	Methanol	SNG
500,000	350,000	460,000	180,000*

Table 7: Production of Chemicals/Fuels (tonnes/annum)

* equivalent to approximately 14.5PJ/y³³

The annual output for urea in Table 7 is constrained by insufficient CO₂ resulting in only 40 % of the ammonia production being converted into urea. If sufficient CO₂ was available, urea production could be increased to 1,000,000 t/a. Co-generation of electricity and synthesis gas (for urea production) would conveniently provide all the CO₂ required. Alternatively surplus Ammonia could be traded on the international market and exported.

Again, determination of the optimal split between electricity and syngas will require a more detailed engineering and market analysis. The capacity to divert production from one stream to the other offers

additional flexibility and potential values.

Ballance Fertiliser currently manufactures 260,000 t/a of urea from natural gas from its plant in Taranaki. Considering the imminent shortage of natural gas in NZ, then synthesis gas produced from an IGCC facility is a possible alternative feedstock. This would avoid the costly reforming step (required to convert methane to CO + H₂ as synthesis feedstock) in the urea process and make synthesis gas more valuable than natural gas. Contact with Ballance reveals a potential interested at an indicated price of around 6.0 NZ\$/GJ for a stoichiometric gas feed, although we would suggest a higher price of closer to 7.50 NZ\$/GJ would be viable. No commercial analysis has been done to support this assumption.

6 International Trends for Gasification

Present global gasification capacity is reported to be around 43,000 MW_{th} synthesis gas from 131 projects; Figure 2^{34,35}. The planned rapid growth of this capacity is mainly in the area of power and chemicals; Figure 3. A similar trend in the use of coal as a feedstock is shown in Figure 4.

Of particular interest to New Zealand is the current developments associated with the Victorian Brown Coals. A proposed US\$4.1 billion phased integrated energy and infrastructure project capable of multiple expansion has been under active review for a number of years.³⁶ (See Appendix). Projects such as these may point the way forward for a NZ development project.

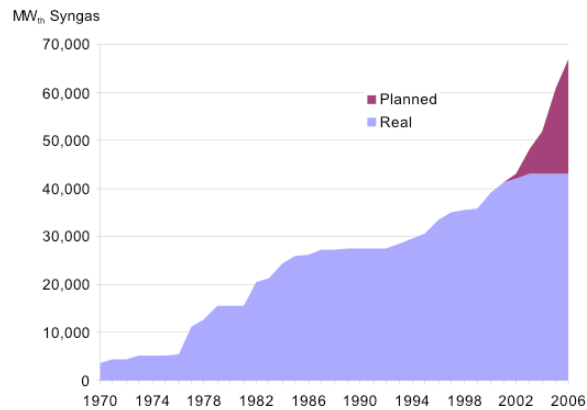


Figure 2: Global gasification capacity

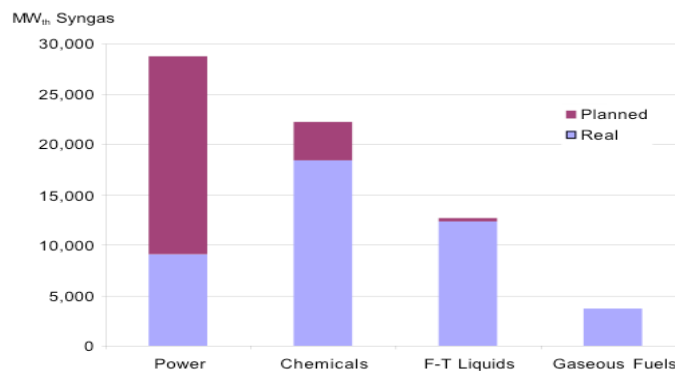


Figure 3: Global gasification by application

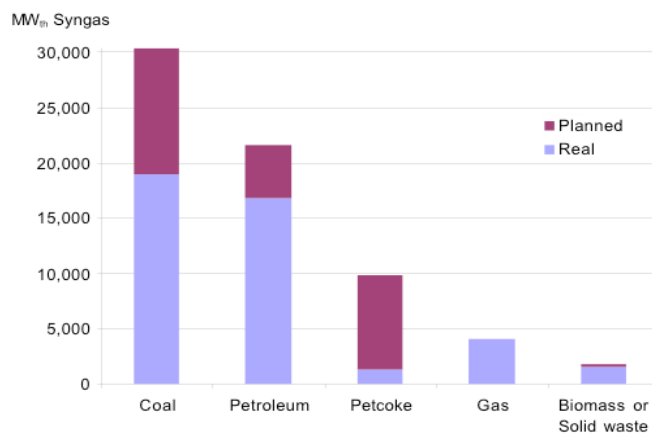


Figure 4: Global gasification by feedstock

Another interesting global trend is the increasing commercial attractiveness of polygeneration incorporating a primary product plus co-generation as shown in Table 8. Of the 21 future planned projects identified, 5 of them will include co-generation.

APPLICATION	MW _{th}	SUPPLIER	COUNTRY
Methanol & electricity	409	Texaco	Italy
Diesel & electricity	727	British Gas/ Lurgi	USA
Hydrogen & electricity	727	“	“
Carbon Monoxide & electricity	48	Texaco	Netherlands
Syngas & electricity	1400	unspecified	USA

Table 8: Planned co-generation projects

Gasification technology is well established and is supported by a number of suppliers; Figure 5. From the review undertaken the Texaco process seems to be the best suited to Kenham’s lignite coals because it is slurry fed. This conclusion, however, would require process licensor confirmation. There are a number of trade-offs that have to be made in process selection that ultimately comes down to determination of the desired product state:

- for slurry-fed gasifiers (Texaco) the lower energy density of the slurry feed increases oxygen consumption and reduces gasification efficiency;
- for dry coal fed gasifiers (Shell) there is an energy penalty (and therefore reduced steam turbine output) for drying high-moisture coals to the level required to ensure reliable feeding.

Gasifier selection is thus about matching coal characteristics with the desired application.

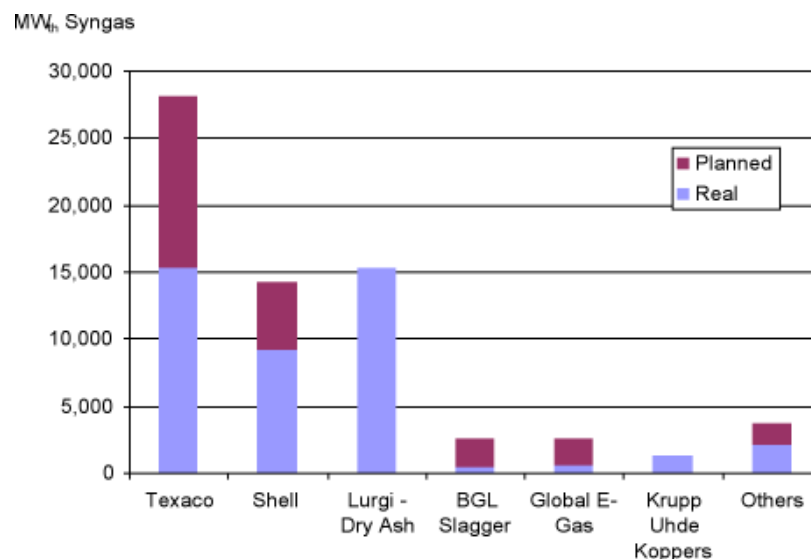


Figure 5: Global gasification by technology

7 Energy Markets

There are basically three energy markets available to a lignite conversion plant in the Otago/Southland region; electricity to the NZ electricity market, fuel gas to meet local energy needs via a purpose built distribution network, or the direct supply of electricity, heat or syngas to a new industry.

We have not sought to assess these markets in particular detail, but instead have examined the likely main drivers for each of the markets identified.

7.1 Electricity

Otago/Southland forecast demand, including Comalco, out to 2011 is approximately 1,050MW (Transpower, 2002). The electricity supply system within the region is based on the Transpower transmission system which links Manapouri to the west, Roxburgh and Dunedin to the north. The transmission and local distribution systems are generally well managed and maintained with supply security from Transpower well able to satisfy normal demand profiles. Transpower anticipates some upgrading of its facilities after 2011.

More important than local demand is the total annual electricity demand growth for New Zealand as a whole, and dry year electricity supply issues in the South Island. The South Island dry year electricity supply problem is compounded because of the lack of thermal generation capacity within the system and the Comalco aluminium smelter has been forced to cut production in dry years. Plans have already been announced for a possible 150 MW coal-fired power station in the Buller region based on West Coast coal.

Although a power plant of this scale using lignite would be uncompetitive in the general market, it may be viable as a provider of power to Comalco (and other local Industries) during dry seasons when a premium price for electricity could be obtained. Such a facility if structured appropriately could well fall within Government's dry-year reserve provisions. These provide for Government to contract with generators for the supply of reserve generation and fuel.

Supply security for New Zealand as a whole, however, offers a more positive driver for additional future large-scale thermal capacity. CAE studies indicate a period of acute natural gas shortage over the next decade with the likelihood of significant demand attrition should there be any delays in the delivery of current planned indigenous offshore gas production (Pohokura and Kupe). Coal remains the most likely backstop fuel, with CAE projections showing Huntly running 90 percent on coal and the installation of two further 400MW capacity thermal power plants at around a five year build period.

Currently gas contracts are clearing in the fuels market at about \$NZ 6.00/GJ. Imported LNG is unlikely at a gas price less than about \$NZ 8.00/GJ, and other options (such as forced renewables) are likely to be more expensive. Indicative future electricity prices based on North Island natural gas are thus predicted to be in the range of \$NZ75-80/MWh, an approximate 40 percent increase from the current average market prices.

7.2 Fuel Gas

In its report to Venture Southland³⁷, East Harbour Management estimates total energy consumption other than electricity (LPG, lignite and coal) for the Southland region to be of the order of 1,300 GWh per year. This includes the cogeneration at Edendale and fuel to the Rayonier MDF plant in Matarua. Clearly opportunity exists to meet some of this load from substitute natural gas or synthesis gas derived from an IGCC plant.

Competitive fuel sources for natural gas are the prospects for frontier gas from Western Southland or the Great South Basin. Again, CAE estimates of the likely gas price required to support exploration and development of these resources is around \$NZ 8-9/GJ. Kenham has significant coal seam gas prospects in the region, which have the potential for much cheaper gas. However, whilst potentially important additional resources, because of gas quality issues marketing of coal seam gas as a fuel gas will be

dependent on having a captive demand adjacent to the coal field or developing an alternative gas market. It is expected, therefore, that coal seam gas would be more likely to be complementary to any lignite development option rather than a stand-alone fuel option although there may be niche opportunities that deserve closer investigation.

7.3 New Industrial Market

Venture Southland, as are other regional economic development agencies, is committed to facilitating the development of existing and new industry where economic opportunity can be captured for the benefit of the local economy. From their work it is assumed that approximately an additional 1,000-1,500 GWh/y of new supply would be required to attract a major consumer to the region.

As previously discussed opportunities span from expansion of the current base metal industry through to petrochemicals; ammonia/urea or methanol. An assessment of Australian aluminium production suggests that at the current NZ/ US exchange rate electricity prices would need to range at somewhere between NZ\$60-90 /MWh (without capital contribution and depending on aluminium price) for investment. It is difficult to make any judgement on the likelihood of attracting further metal industry investment in the region based on these predicted electricity prices.

Of the petrochemicals options, ammonia/urea offers perhaps the most attractive option as there is already an established domestic and export market for this. Methanol is an international traded commodity, as a chemical grade product. Whilst it is technically feasible to produce a fuel grade methanol, heat balance considerations within the plant would simply mean that the economies of the fuel grade-option are unlikely to support a stand-alone facility.

8 Capture and Disposal of CO₂

Government environmental policy is driving the need to consider reduction in CO₂ emissions associated with chemical and energy projects based around coal as feedstock. While consideration of this issue is not part of this project, it was nevertheless felt appropriate to at least draw attention to current trends.

For example, in gasification-based ammonia plants, capture and usage of CO₂ is commonplace. Selling CO₂ for “enhanced oil recovery” (EOR) from producing reservoirs is another proven option. But most CO₂ will have to be sequestered underground in either depleted gas fields, deep saline aquifers, unmineable coal seams, or deep-sea basins. In the case of Hawkdun and Ashers-Waituna, coal seams are likely to be the most prospective, perhaps even in conjunction with enhanced recovery of coal seam gas.

There is an international research effort underway, much of it co-ordinated by IEA (of which CRL Energy Limited is a member). An informal overview of this effort is given in Appendix III.

9 Conclusions and Recommendations

The study has highlighted that South Island lignite, such as at Hawkdun and Ashers-Waituna, offer a potentially viable future feedstock for electricity production and possible conversion to petrochemicals. In the near –to-medium term the likely competing fuels for the NZ thermal fuels market will be imported LNG or frontier gas outside of the existing onshore and offshore Taranaki gas fields, with perhaps some additional contribution from indigenous coal.

Whilst coal gasification is a complex technology, a review of world gasification databases has identified a significant number of operating gasification plants both for electricity and chemicals manufacture. The recent trend is towards polygasification plant, initially based on refinery residues, for industrial use with the manufacture of ammonia as a primary product from the synthesis gas feed. New gasification plants either planned or in construction are dominated by the Texaco and Shell licensed technologies. Experience from these plants will determine the future rate of uptake towards coal as a feedstock. Industry views are that natural gas will be increasingly too expensive and valuable for industrial use. Current projections for imported LNG into the NZ market are of the order of \$NZ 8.00/GJ.

Given that New Zealand will fast become entirely dependent on imported nitrogenous fertilisers due to the imminent shortfall in the country's natural gas supply there will be in the near term commercial opportunity to augment natural gas supply with the production of synthesis gas for the manufacture of nitrogenous fertilisers, especially urea. Further, the availability of surplus synthesis gas may offer other incremental fuel opportunities (SNG) within the Southland/Otago region.

Kenham is thus advised to adopt a long-term view on its lignite holdings, primarily focusing on using the lignite to meet the chemicals and fuels needs of the country and treating the generation of electricity as a means of attaining economy of scale. To this end our key recommendations are:

1. Coal gasification is the preferred option for conversion of the lignite. Gasification offers proven technology and the cost basis can be established with confidence.
2. Lignite offers a potentially viable feedstock for production of synthesis gas for conversion to petrochemicals. The most attractive product currently appears to be ammonia for fertiliser manufacture.
3. The cost of generating electricity from lignite for supply to the domestic market is not likely to be competitive due to the remoteness of the deposits from the main markets in the North Island.
4. There may be a case in the near term for a smaller scale facility to supply power to the aluminium industry in Southland during dry years when hydroelectric power is not available. Underwriting of such a venture could be available via Government's dry-year reserve provision.
5. Further study work should be conducted. This should include definition of the coal properties and detailed study of the economics of production of the various petrochemical/fuels options. Electricity generation for support of industry during dry years should be investigated as a matter of priority.

Finally we comment that in any future work special attention should be given to understanding the sensitivity of IGCC to variations in lignite characteristics. This should entail developing preliminary mining plans for each deposit in order to allow estimation of short-term variabilities in lignite quality, and ash content. Prior to any full feasibility assessment macro samples of coal across the composition spectrum will need to be gasified in a licenser facility (by Texaco for example) and guaranteed synthesis gas compositions determined for process selection and detailed design.

In the interim, however, much can be done to establish the alternative project configurations, greenhouse gas management strategies and the market basis for future capital raising and feasibility assessment. In particular, additional work is recommended to more fully assess geosequestration solutions and their related process engineering implications so as to optimise the gasification/synthesis route. So doing will allow better assessment of project costing, business appraisal, and hence the identification of potential commercial partners.

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Appendices

Appendix 1: Review of Gasification Technology

Appendix 2: Selected Lignite Deposit Characteristics

Appendix 3: Carbon Capture and Sequestration

Appendix 1

Review of Gasification Technology

A General Literature Review

1.1 Gasification Introduction

Gasification today is a commercially proven technology. The technology first became important in the second half of the eighteenth century when coal was gasified commercially for the first time, in England, to produce town gas for light and heating. Gasification involves the partial oxidation of carbonaceous feedstocks (gases, liquids or solids) by heating in the presence of steam and oxygen to produce synthesis gas (syngas) which is basically a mixture of hydrogen, carbon monoxide, some carbon dioxide and a little methane. The syngas, so produced, is then converted to gaseous and liquid fuels, chemicals or combusted to produce electricity.

Worldwide commercial scale gasification capacity currently operating or under construction accounts for 131 projects with a combined rating of 43.3 GW(thermal) of synthesis gas - equivalent to 23.8 GW(electrical), IGCC equivalent. Table A1 lists the top 11 coal gasification plants operating worldwide (Higman et al, 2003). The three SASOL plants, plus the plants in the Dakota and Shanghai use low rank coals similar to South Island lignites. Annual growth rates of between 4000 to 5000 MW_{th} of installed capacity have been achieved over recent years (Simbek and Johnson, 2001).

Plant	Country	Technology	MW _{th} Syngas	Start Up	Feed/Product
Sasol-II	SA	Lurgi Dry Ash	4130	1977	Sub-But. Coal / F-T liquids
Sasol-III	SA	Lurgi Dry Ash	4130	1982	Sub-But. Coal / F-T liquids
Dakoto	USA	Lurgi Dry Ash	1545	1984	Lignite & Refinery residue / SNG
Sasol-I	SA	Lurgi Dry Ash	911	1955	Sub-But. Coal / F-T liquids
SUV/EGT	Czech Rep.	Lurgi Dry Ash	636	1996	Coal / Elec. & Steam
PubService of Indiana	USA	Destec (E-Gas)	591	1995	Bit. Coal / Elec.
Elcogas SA	Spain	RENFO	588	1997	Coal & Petcoke / Elec.
Demkolec BV	Netherlands	Shell	466	1994	Bit. Coal / Elec.
Taiupa Electric Co.	USA	Texaco	455	1996	Coal / Elec.
Shanghai Pacific Chemical Corp.	China	Texaco	439	1995	Anthracite Coal / Methanol & Town Gas
Ditto	China	IGT U-Gas	410	1994	Bit. Coal / Fuel Gas & Town Gas

Table A1: The top 11 world coal gasification plants

Generally speaking, gasifiers can be grouped into one of three categories based on the reactor type: moving-bed gasifiers, fluid-bed gasifiers, and entrained flow gasifiers. Higman and van der Burgt (2003) note that “The majority of the most successful gasification processes that have been developed after 1950 are entrained-flow gasifiers operating at pressures of 20-70 bar and at high temperatures of at least 1400°C. Entrained-flow gasifiers have become the preferred gasifier for hard coals and have been selected for the majority of commercial sized IGCC applications.”

The two major entrained-flow gasifier types are those licensed by Texaco and Shell. These two gasifiers have many differences including the method of delivering the coal into the reactor. Texaco offer a slurry-feed gasifier whilst the Shell gasifier requires dry coal, pneumatically conveyed with an inert gas carrier and fed to the gasifier via lock hoppers.

The literature of gasification is extremely fragmented with almost all recent contributions being confined to conference papers or articles in scientific journals. As a result the knowledge of gasification is mostly

confirmed to commercial process licensors and the operators of existing plants. SFA Pacific Inc. have maintained a database of gasification projects since 1999. Their most recent version is included in this appendix. Importantly, they identify 32 planned gasification projects with a total of 59 gasifiers rated at about 24.5 GW_{th} or about 13.6 GW_e, IGCC equivalent.

International trends for gasification investment are described in the main body of the report, with most new investment planned for the USA, China and Italy. The driving forces for gasification are the current high and uncertain natural gas price, especially in the US, poor markets for high sulphur petroleum coke residues from modern refinery operations, combined with deregulation of the electric power industry world-wide.

Polygeneration projects (defined as gasification for syngas turbine-based steam/power plants plus syngas conversion to chemicals and fuels) offers great opportunity for use of low-value residual feedstocks derived from the refining of low quality crude oils, plus more flexible product slates including hydrogen and oxy chemicals. In addition new gasification combined cycle technology offers strategic advantages for the repowering of existing coal-field power units from better emissions control and the mitigation of natural gas price/supply risks.

Together these factors suggest that gasification will play a vital role in the future; both for power generation and the production of base chemicals. Gasification as a key technology for more efficient power generation from coal and low value residual fuels and, as well, gasification-based processes have a natural advantage over combustion technologies when it comes to CO₂ capture. Demand for electricity in developed countries is growing at a rate twice that of other energy forms. As natural gas price increases, gasification will become more competitive as it enables all feedstocks to meet the same emission levels as natural gas combined cycle power generation.

1.2 Gasification Technologies

The history of gasification and gasification processes are very well treated in the reference book "Gasification" (Higman and van der Burgt, 2003). The characteristics of the different gasification processes as described in Table A.2 are taken from this reference.

Category	Moving Bed		Fluid Bed		Entrained Flow
Ash conditions Typical Processes	Dry ash Lurgi	Slagging BGL BGL	Dry ash Winkler, HTW, CFB	Agglomerating KRW, U-gas	Slagging, Shell, Texaco, E-Gas, Noell, KT
Feed Characteristics					
Size	6-50 mm	6-50 mm	6-10 mm	6-10 mm	<100mm
Acceptability of fines	limited	better than dry ash	good	better	unlimited
Acceptability of caking coal	yes (with stirrer)	yes	possibly	yes	yes
Preferred coal rank	any	high	low	any	any
Operating Characteristics					
Outlet gas temperature	low (425-650°C)	low (425-650°C)	moderate (900-1050°C)	moderate (900-1050°C)	high (1250-1600°C)
Oxidant demand	low	low	moderate	moderate	high
Steam demand	high	low	moderate	moderate	low
Other characteristics	hydrocarbons in gas	hydrocarbons in gas	lower carbon conversion	lower carbon conversion	pure gas, high carbon conversion

Table A2: Characteristics of different gasification processes

As previously described, the majority of the successful gasification processes that have been developed after 1950 are entrained-flow gasifiers. This gasifier type operates with the feed and reactive gas blast in co-current flow. Residence time is short (a few seconds) which avoids unwanted side reactions and

carbonisation but, as a consequence, high temperatures are required to ensure good conversion and, therefore, all entrained-flow gasifiers operate in the slagging range. Importantly, however, the entrained-flow process does not have any specific limitations on the type of coal used.

Analysis of the South Island lignites contained in the Liquid Fuels Trust Board report (LF 2028) suggests that both the Hawkdun and Ashers-Waituna coals are likely to be suitable feedstocks. On the basis of maceral distribution it is likely that the Hawkdun deposits will have a higher reactivity than Ashers-Waituna, but this is counter-balanced by the greater presence of exchangeable alkaline and alkaline earth metals in the Ashers-Waituna lignites that will act to promote gasification reactivity. Ash slagging temperatures are around 1300°C, well within the likely operating temperature range of the process.

Of the two major entrained-flow gasifier types, the Shell Coal Gasification Process is by far the newer, developed in 1978 jointly with Koppers-Totzek with the first commercial unit constructed in 1994. The Texaco process, on the other hand, was developed in the late 1940's with the first commercial plant built in 1950, based on a natural gas feedstock. Over the next 50 years more than 100 reactors have been licensed for oil or gas partial oxidation, predominantly for chemicals manufacture.

Since 1990, however, nine commercial coal-based plants have been brought into service. The Texaco process is by far the less capital intensive, but has a high maintenance requirement. Process selection thus needs to bring into consideration plant availability factors.

A process flow diagram for the Texaco gasification system is shown in Figure A1 below.

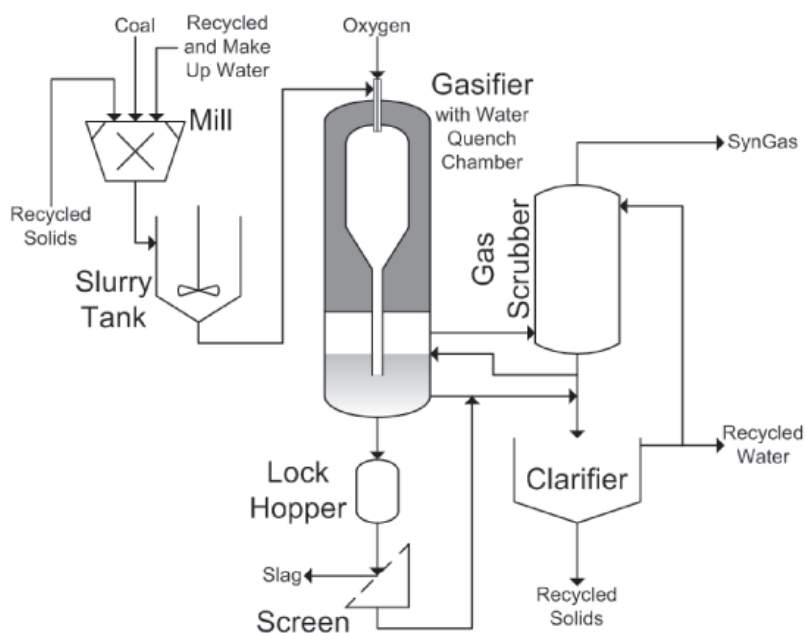


Figure A1: Texaco Gasification (Quench Configuration)

Feed coal is milled to a particle size of about 100 µm and slurried in conventional milling equipment. The slurry is then introduced into the reactor via a membrane pump at between 30-70 bar depending upon configuration and downstream processing requirements. Oxygen is introduced through the same injector which is generally located centrally on top of the gasifier. The gasification takes place just above slagging temperatures (where the ash turns into a viscous liquid).

After a relatively short time in the gasification chamber, the reactants, together with the liquid ash enters the water in the quench chamber. This causes the slag to solidify and fall to the bottom of the chamber while the raw synthesis gas, which is cooled to between 200 and 300°C, bubbles to the surface and leaves the quench chamber fully saturated. The slag is removed via a lock hopper, the associated water separated from the slag and recycled for use in the coal slurry.

Raw synthesis gas is passed through a scrubber to remove particulates and hydrogen chloride. After that it passes through a catalyst bed (not shown) to remove any sulphur. Other possible configurations include recovery of the reaction heat as high pressure steam via radiant cooling of the syngas product.

Using the Texaco process, the following composition for raw synthesis gas from lignite is predicted. This gas composition and gas condition is suitable for direct CO shift conversion for hydrogen or ammonia manufacture.

	Mol %
Carbon monoxide	57.6
Hydrogen	33.3
Carbon dioxide	6.3
Argon	0.6
Nitrogen	1.0
Hydrogen sulphide	0.2

1.3 Integrated Gasification Combined Cycle power generation

The integrated gasification combined cycle (IGCC) power station in its present form is basically a combination of gasification and a conventional Combined Cycle plant. The advantage of a gasification front-end is the energy efficiency gains that can be achieved through plant integration and better environmental performance.

Although the two components of an IGCC facility are both well developed technologies, their combination is relatively new. It is important to note that development of the IGCC technology is being led by the international petrochemical companies such as Shell, Dow and Texaco. This is not a technology suited to the traditional electric generating companies as they do not have the skills or the experienced people to operate such plants. As a consequence traditional power-based generators see IGCC as “demonstration” technology and not suitable to a conventional utility business.

However, deregulation of the power industry is removing barriers to entry with IGCC plant providing greater flexibility than conventional Rankine Cycle power plant to face the many uncertainties that challenge future power generation. The features of the IGCC route are many (PB Power, 2004):

- high efficiency, currently up to 41% HHV
- potential to reach 45-50% with new gas turbine and air separation technology
- good control of air emissions
- significant advantage over PC combustion technologies for CO₂ recovery

O’Keefe and Strum, (2002) in a study based on using Texaco gasification with total water quench and at 80 bars estimated that the addition of CO₂ capture resulted in only a 5% additional capital cost increment and an efficiency penalty of 2%. Again these types of techniques involve chemical process expertise and are thus largely ignored by the utilities companies and their advisors.

The flow scheme for a combined cycle (CC) plant is shown below.

The two cycles in the combined cycle are the joule cycle and the steam cycle. The dashed line in Figure A2 makes this distinction. The most common use of the joule cycle operating alone is the jet engine of an aircraft. In this system air is compressed in a compressor, and the pressurised air is used for the combustion of the fuel. The resulting very hot gases then enter the turbine, and the hot exhaust gas leaves the system. Standing alone this system has a thermal efficiency of about 43%. To improve this efficiency in a power plant, this cycle is combined with a steam cycle which uses the hot exhaust gas

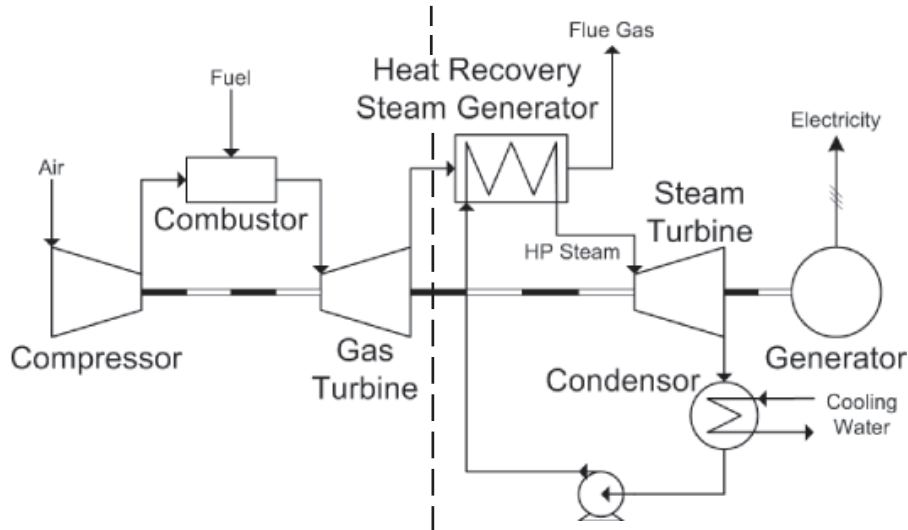


Figure A.2: Schematic of Combined Cycle Power Plant

leaving the gas turbine as a heat source. This heat is recovered in the heat recovery steam generator (HRSG) and used to power the steam turbine. Integration of the two cycles increases thermal efficiency to almost 60%.

Conventional CC plants are limited by the exit temperature of the hot gases from the gas turbine stage (around 550°C) which limits the degree of superheat that can be achieved in the subsequent steam cycle. Close integration with a gasification unit has the potential to alleviate this problem, and thus provide more superheat. Effective integration thus requires detailed engineering to optimise the overall process flow sheet (Holt, 2002).

1.4 Chemical and Fuels from Synthesis Gas

The conversion of synthesis gas to chemical and fuels involves basically three process routes:

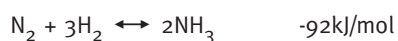
- further synthesis to ammonia, methanol and other chemicals
- Fischer Tropsch conversion to liquid fuels plus some chemicals
- methane synthesis to produce synthetic natural gas (SNG)

Detailed examination of these options is well beyond the scope of this study as essentially the technologies and process options are extensive, widely available and commercially proven. The critical process engineering factor to take into consideration is the need to adjust the syngas composition to match feedstocks requirements for downstream processing.

Apart from the obvious requirement for gas clean-up to remove impurities (especially for catalytic processes), the major processing requirement is the adjustment of the H₂ and (CO + CO₂) ratios to achieve stoichiometry. This is effected by gasification operating pressures, oxygen feed quality and subsequent CO shift/CO₂ removal to increase H₂ content. A brief summary of the feedstock requirements for a range of processing routes of potential interest to New Zealand is set out below:

Ammonia

The world wide production of ammonia is the largest of any bulk chemical, with its major use being as a nitrogenous fertiliser. In New Zealand ammonia production is based on air/steam reforming of natural gas. However, ammonia synthesis can also take place at high pressures over an iron catalyst according to the following reaction:



Typical feedstock specifications are: a N₂:H₂ ratio of 1:3, with CO + CO₂ content of less than 30 ppmv, a

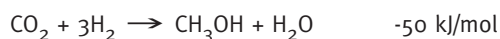
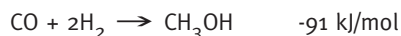
sulphur content of less than 1 ppmv, and less than 2% inerts, including methane.

Most ammonia plants are built in conjunction with urea plants, the CO₂ from the ammonia plant being used directly for the production of urea:



Methanol

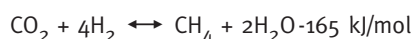
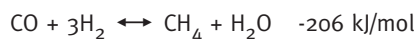
Methanol synthesis takes place at the relatively low pressures of 50 to 100 bar over a copper catalyst according to the following reactions:



Ideally, the feedstock synthesis gas has the following specification: 3 mol% CO₂, a stoichiometric ratio of 2.03 (i.e. (H₂ - CO₂)/(CO + CO₂) = 2.03), less than 0.1 ppmv of H₂S and a minimum amount of inerts including methane. Once again gasification can achieve these specifications. In fact, gasification is significantly better than the standard conventional steam reforming of natural gas, which has a stoichiometric ratio of 2.7

Synthetic Natural Gas (SNG)

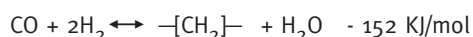
SNG consists primarily of methane, which is synthesized by the reaction of carbon oxide with hydrogen over a nickel catalyst according to the equations:



Specification for SNG require a maximum hydrogen content of 10%. Typically a stoichiometric number (i.e. H₂/(3CO + 4CO₂)) of 0.98 to 1.03 is required

Fischer Tropsch Liquids

Fischer-Tropsch synthesis has been used in South Africa for over 40 years for the production of hydrocarbon liquids. Modern plants for the conversion of natural gas via partial oxidation are also in operation in Malaysia and South Africa. The basic Fischer-Tropsch process produces a mixture of straight chain hydrocarbons from hydrogen and carbon monoxide according to the reaction:



Selectivity is dependent on catalyst type and operating conditions (reactor type) Syngas specification for typical process configuration (H₂/CO ratio) are: Arge 1.3 – 2.3, SMDS 1.5 – 2, and Synthol 2.6.

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Listing of Gasification Plants Sorted by Region and Country

(From SFA Pacific Inc., 2004)

Gasifier Plant Owner	Location	No. of Gasifiers Operating/Spare Gas'n Tech.	MWth Fuel Input/SG Out	Syngas Cap., Eq. IGCC Nm3/d Cap., MWt Status	Year	Feed Class / Product Category
Active-Real Projects						
Africa/Middle East						
Egypt						
Nitrogen Works of Societé el Nasr d' Engrois	Talkha	3/ 0	125 / 106	778,000	1966	Gas / Chemicals
Total Gasifiers in Egypt in 1 Projects						
		3/ 0	125 / 106	778,000	58	Operating
South Africa						
Sasol Chemical Industries (Pty.) Ltd./Sasol Ltd.	Sasolburg	15/ 2	1,169 / 971	7,100,000	1955	Coal / FT liquids
Sasol (Pty) Ltd.	Secunda, Mpumalanga	40/ 0	8,810 / 7,048	39,600,000	1977	Coal / Chemicals
Sasol (Pty) Ltd.	Secunda, Mpumalanga	40/ 0	8,810 / 7,048	39,600,000	1982	Coal / Chemicals
Total Gasifiers in South Africa in 3 Projects						
		95/ 2	18,789 / 15,067	86,300,000	6,442	Operating
Zambia						
Nitrogen Chemicals of Zambia (NCZ)	Kafue	2/ 1	150 / 120	877,000	1970	Coal / Chemicals
Total Gasifiers in Zambia in 1 Projects						
		2/ 1	150 / 120	877,000	65	Operating
Total Gasifiers in Africa/Middle East in 5 Projects						
		100/ 3	19,065 / 15,293	87,955,000	6,566	Operating
Asia/Australia						
Australia						
BOC Gases						
	Brisbane, Queensland	2/ 0	129 / 110	805,000	2000	Gas / Chemicals
Total Gasifiers in Australia in 1 Projects						
		2/ 0	129 / 110	805,000	60	Operating
China						
Zhenhai Refining & Chemical Co.	Ningbo, Zhejiang	3/ 0	350 / 287	2,100,000	1983	Petroleum / Chemicals
China National Petrochemical Corp./Sinopec	Urumqi	3/ 0	358 / 287	2,100,000	1985	Petroleum / Chemicals
China National Petrochemical Corp./Sinopec	Daqing	1/ 0	35 / 29	210,000	1986	Petroleum / Chemicals
China National Technology Import Co. (CNTIC)	Shaanxi	3/ 1	367 / 312	2,282,492	1987	Coal / Chemicals
Qilu Petrochemical Ind.	Zibo, Shandong	2/ 0	119 / 98	715,000	1987	Petroleum / Chemicals
CNPC Ningxia Dayuan Refining & Chemical Ind. Co. Ltd.	Xishi District, Yinchuan, Ningxia	3/ 0	417 / 342	2,500,000	1988	Petroleum / Chemicals
Fushun Detergent Co.	Fushun, Liaoning	1/ 0	10 / 8	60,000	1991	Petroleum / Chemicals
Lu Nan Chemical Industry (Group) Co./CNTIC	Tengxian, Shandong	2/ 0	96 / 72	525,000	1993	Coal / Chemicals
Shanghai Pacific Chemical (Group) Co., Ltd.	Wujing, Shanghai	6/ 2	513 / 410	3,000,000	1994	Coal / Gaseous fuels
Beijing No. 4 Chemical	Beijing	1/ 0	53 / 44	320,000	1995	Petroleum / Chemicals
Dalian Chemical Industrial Corp.	Dalian, Liaoning	2/ 0	358 / 287	2,096,500	1995	Petroleum / Chemicals
Inner Mongolia Fertilizer Co.	Hohhot, Inner Mongolia	2/ 0	350 / 287	2,100,000	1996	Petroleum / Chemicals
Juijiang Petrochemical Co.	Juijiang, Jiangxi	2/ 0	350 / 287	2,100,000	1996	Petroleum / Chemicals
Weihe Fertilizer Co.	Xian, Shaanxi	2/ 1	372 / 279	2,040,000	1996	Coal / Chemicals
Shanghai Pacific Chemical Corp.	Wujing, Shanghai	3/ 0	279 / 209	1,530,000	1997	Coal / Chemicals
Lanzhou Chemical Industrial Co.	Lanzhou, Gansu	2/ 0	350 / 287	2,100,000	1998	Petroleum / Chemicals
Henan	Puyang	3/ 1	367 / 312	2,282,492	2000	Coal / Chemicals
Huainan General Chemical Works	Hefei City, Anhui	3/ 0	255 / 191	1,400,000	2000	Coal / Chemicals
Jilin Chemical Industrial Corp.	Jilin City, Jilin	2/ 0	358 / 287	2,096,500	2002	Petroleum / Chemicals
Nanjing Chemical Industry Co.	Nanjing, Jiangsu	2/ 0	346 / 301	2,200,000	2002	Petroleum / Chemicals

Gasifier Plant Owner	Location	No. of Gasifiers Operating/Spare	Gasifier Tech.	MWth		Syngas Cap., Eq. IGCC Nm ³ /d	Cap.	MWth Status	Year	Feed Class / Product Category
				Fuel Input/SG Out	Cap.					
Shuanghuan Chemical Co.	Yingcheng, Hubei	1/ 0	Shell	226 /	181	1,320,000		99 Construction	2004	Coal / Chemicals
Lizhou Chemical Industry Corp. Ltd.	Lizhou, Guangxi	2/ 0	Shell	359 /	287	2,100,000		157 Construction	2005	Coal / Chemicals
Sinopec Jinling Petrochemical Corp.	Jinling	2/ 0	GE (Texaco)	350 /	287	2,100,000		157 Construction	2005	Petcoke / Chemicals
Sinopec/Shell	Yueyang, Hunan	1/ 0	Shell	583 /	466	3,410,000		255 Construction	2005	Coal / Chemicals
Dahua Chemical Corp.	Dalian, Liaoning	1/ 0	Shell	256 /	205	1,500,000		112 Construction	2006	Coal / Chemicals
Sinopec/Shell	Anqing, Anhui	2/ 0	Shell	581 /	465	3,400,000		254 Construction	2006	Coal / Chemicals
Sinopec/Shell	Zhijiang, Hubei	2/ 0	Shell	581 /	465	3,400,000		254 Construction	2006	Coal / Chemicals
Yun Zhanhua Chemical Corp.	Qujing, Yunnan	2/ 0	Shell	581 /	465	3,400,000		254 Construction	2006	Coal / Chemicals
Yuntianhua Chemical Corp.	Anning, Yunnan	2/ 0	Shell	581 /	465	3,400,000		254 Construction	2006	Coal / Chemicals
Total Gasifiers in China in 29 Projects		63/ 5		9,801 /	7,900	57,787,984		4,314		
India										
Fertilizer Corp. of India Ltd.	Sindri, Punjab	3/ 0	Shell	350 /	287	2,100,000		157 Operating	1977	Petroleum / Chemicals
Hindustan Fertilizer Corp. Ltd.	Haldia, New Delhi	3/ 0	Shell	350 /	287	2,100,000		157 Operating	1978	Petroleum / Chemicals
National Fertilizers Ltd.	Nangal, Punjab	3/ 0	Shell	350 /	287	2,100,000		157 Operating	1978	Petroleum / Chemicals
National Fertilizers Ltd.	Panipat, Haryana	3/ 0	Shell	350 /	287	2,100,000		157 Operating	1978	Petroleum / Chemicals
Fertilizer Corp. of India Ltd.	Ramagundam, Andhra Pradesh	3/ 0	Koppers-Totzek	342 /	273	2,000,000		149 Operating	1979	Coal / Chemicals
Fertilizer Corp. of India Ltd.	Talcher, Orissa	3/ 0	Koppers-Totzek	342 /	273	2,000,000		149 Operating	1979	Coal / Chemicals
National Fertilizers Ltd.	Bathinda, Punjab	3/ 0	Shell	350 /	287	2,100,000		157 Operating	1979	Petroleum / Chemicals
Neyveli Lignite Corp. Ltd.	Neyveli, Tamil Nadu	2/ 0	Shell	133 /	109	800,000		60 Operating	1979	Petroleum / Chemicals
Gujarat Narmada Valley Fertilizers Co. Ltd.	Bharuch, Gujarat	2/ 1	GE (Texaco)	507 /	405	2,964,600		221 Operating	1982	Petroleum / Chemicals
Indian Oil Corp. Ltd.	Nagapattinam, Orissa	2/ 1	Shell	854 /	684	5,000,000		373 Engineering	2006	Petcoke / Chemicals
Total Gasifiers in India in 10 Projects		27/ 2		3,929 /	3,181	23,264,600		1,737		
Japan										
Mitsubishi Petrochemicals	Yokkaichi	2/ 0	Shell	67 /	55	400,000		30 Operating	1961	Petroleum / Chemicals
Mitsui	Omura	2/ 0	GE (Texaco)	100 /	82	600,000		45 Operating	1961	Petroleum / Chemicals
Ube Ammonia Industry Co. Ltd.	Ube City	1/ 0	GE (Texaco)	36 /	27	200,000		15 Operating	1982	Petcoke / Chemicals
Unspecified owner	Unspecified location	2/ 0	GE (Texaco)	92 /	75	550,000		41 Operating	1982	Petroleum / Chemicals
Ube Ammonia Industry Co. Ltd.	Ube City	3/ 1	GE (Texaco)	392 /	294	2,150,000		161 Operating	1984	Coal / Chemicals
Nippon Petroleum Refining Co.	Yokohama	2/ 0	GE (Texaco)	967 /	793	5,800,000		433 Operating	2003	Petroleum / Power
Total Gasifiers in Japan in 6 Projects		12/ 1		1,654 /	1,326	9,700,000		724		
Malaysia										
Shell MDS (Malaysia) Sdn. Bhd.	Bitulu, Sarawak	6/ 0	Shell	1,215 /	1,032	7,552,000		564 Operating	1993	Gas / FT Liquids
Total Gasifiers in Malaysia in 1 Projects		6/ 0		1,215 /	1,032	7,552,000		564		
Singapore										
Singapore Syngas Pre. Ltd. (Linde)	Jurong Island	2/ 0	GE (Texaco)	268 /	220	1,610,000		120 Operating	2000	Petroleum / Chemicals
Esso Singapore Pty. Ltd.	Pulau Ayer Chawan, Jurong Island	2/ 0	GE (Texaco)	450 /	364	2,660,000		199 Operating	2001	Petroleum / Power
Total Gasifiers in Singapore in 2 Projects		4/ 0		718 /	584	4,270,000		319		
South Korea										
Lucky Goldstar Chemical Ltd.	Yochon	1/ 0	Shell	64 /	53	384,000		29 Operating	1996	Petroleum / Chemicals
Unspecified owner	Unspecified location	1/ 0	GE (Texaco)	100 /	82	600,000		45 Operating	1997	Petroleum / Chemicals
Lucky Goldstar Chemical Ltd.	Naju, Seoul	1/ 0	Shell	117 /	96	700,000		52 Operating	2001	Petroleum / Chemicals

Gasifier Plant Owner	Location	No. of Gasifiers: Operating/Spare Gas'n Tech.	MWth Fuel Input/SG Out	Syngas Cap., Eq. IGCC Nm3/d Cap., MWc Status	Year	Feed Class / Product Category
Total Gasifiers in South Korea in 3 Projects		3/ 0	281 / 230	1,684,000	126	
Taiwan						
Chinese Petroleum Corp.	Kaohsiung	2/ 0 GE (Texaco)	391 / 293	2,143,000	160 Operating	1984 Petroleum / Chemicals
Total Gasifiers in Taiwan in 1 Projects		2/ 0	391 / 293	2,143,000	160	
Total Gasifiers in Asia/Australia in 53 Projects		119/ 8	18,117 / 14,656	107,206,584	8,003	
Central & South America/Caribbean						
Brazil						
Ultrafertil S.A.	Araucária	3/ 0 Shell	550 / 451	3,300,000	246 Operating	1979 Petroleum / Chemicals
Total Gasifiers in Brazil in 1 Projects		3/ 0	550 / 451	3,300,000	246	
Dominican Republic						
Falconbridge Dominicana	Santo Domingo	12/ 0 Shell	240 / 197	1,440,000	107 Operating	1971 Petroleum / Chemicals
Total Gasifiers in Dominican Republic in 1 Projects		12/ 0	240 / 197	1,440,000	107	
Total Gasifiers in Central & South America/Caribbean in 2 Projects		15/ 0	790 / 648	4,740,000	354	
Eastern Europe/Former Soviet Union						
Czech Republic						
Sokolovska Uhelna, A.S.	Vresova	13/ 13 Lurgi Dry Ash	796 / 636	4,700,000	351 Operating	1996 Coal / Power
Chemopetrol a.s.	Most (formerly Brúx), Litvínov	6/ 0 Shell	600 / 492	3,600,000	269 Operating	2001 Petroleum / Chemicals
Total Gasifiers in Czech Republic in 2 Projects		19/ 13	1,396 / 1,129	8,300,000	620	
Poland						
Grupa Lotos SA (Raf. Gdanska)	Gdansk	3/ 0 Shell	784 / 643	4,700,000	351 Construction	2006 Petroleum / Chemicals
Total Gasifiers in Poland in 1 Projects		3/ 0	784 / 643	4,700,000	351	
Total Gasifiers in Eastern Europe/Former Soviet Union in 3 Projects		22/ 13	2,179 / 1,771	13,000,000	970	
North America						
Canada						
Long Lake Project (OPTI Canada/Nexen)	Fort McMurray, Alberta	3/ 0 Shell	1,250 / 1,025	7,500,000	560 Construction	2006 Petroleum / Chemicals
Total Gasifiers in Canada in 1 Projects		3/ 0	1,250 / 1,025	7,500,000	560	
United States						
Hoechst Celanese	Houston, TX	3/ 0 Shell	338 / 287	2,100,000	157 Operating	1977 Gas / Chemicals
Exxon Chemical Co.	Baton Rouge, LA	3/ 0 Shell	95 / 78	570,000	43 Operating	1978 Petroleum / Chemicals
Hoechst Celanese	Bay City, TX	2/ 0 GE (Texaco)	83 / 68	500,000	37 Operating	1979 Petroleum / Chemicals
Millennium (Quantum)	Deer Park/LaPorte, TX	2/ 0 GE (Texaco)	772 / 656	4,800,000	358 Operating	1979 Gas / Chemicals
Eastman Chemical Co.	Kingsport, TN	1/ 1 GE (Texaco)	292 / 219	1,600,000	119 Operating	1983 Coal / Chemicals
Unspecified owner	Unspecified location	1/ 0 GE (Texaco)	64 / 55	400,000	30 Operating	1983 Gas / Chemicals
Unspecified owner	Unspecified location	2/ 0 GE (Texaco)	134 / 114	830,000	62 Operating	1983 Gas / Chemicals
Dakota Gasification Co.	Bismarck, ND	12/ 2 Lurgi Dry Ash	2,534 / 1,900	13,900,000	1,038 Operating	1984 Coal / Gaseous fuels
Motiva Enterprises LLC	Convent, LA	2/ 0 GE (Texaco)	313 / 257	1,880,000	140 Operating	1984 Petroleum / Chemicals
Global Energy, Inc.	West Terre Haute, IN	1/ 1 E-GAS (Destec/Dow)	738 / 591	4,320,000	322 Operating	1995 Petroleum / Power
Union Carbide Corp.	Taft, LA	1/ 0 GE (Texaco)	70 / 59	432,000	32 Operating	1995 Gas / Chemicals
Air Products & Chemicals, Inc.	LaPorte, TX	2/ 0 GE (Texaco)	316 / 253	1,850,000	138 Operating	1996 Gas / Chemicals

Gasifier Plant Owner	Location	No. of Gasifiers Operating/Spare Gas'n Tech.	MWh Fuel Input/SG Out	Syngas Cap., Eq. IGCC Nm3/d	Cap., MW	Status	Year		Feed Class / Product Category
							1996	2006	
Frontier Oil & Refining Co.	El Dorado, KS	1/ 0 GE (Texaco)	15 / 11	80,559		6 Operating	1996	Petcoke / Power	
T & P Syngas (Texaco/Praxair)	Texas City, TX	1/ 0 GE (Texaco)	348 / 278	1,920,000		143 Operating	1996	Gas / Chemicals	
Tampa Electric Co.	Mulberry, FL	1/ 0 GE (Texaco)	602 / 451	3,300,000		246 Operating	1996	Coal / Power	
Unspecified owner	Unspecified location	1/ 0 GE (Texaco)	56 / 48	350,000		26 Operating	1998	Gas / Chemicals	
Coffeyville Resources Refining & Marketing LLC	Coffeyville, KS	1/ 1 GE (Texaco)	390 / 293	2,141,200		160 Operating	2000	Petcoke / Chemicals	
ExxonMobil	Baytown, TX	2/ 0 GE (Texaco)	423 / 347	2,540,000		190 Operating	2000	Petroleum / Chemicals	
Air Liquide America Corp.	Longview, TX	2/ 0 GE (Texaco)	251 / 213	1,558,000		116 Operating	2002	Gas / Chemicals	
Premcor Refining Group, Inc.	Delaware City, DE	2/ 0 GE (Texaco)	693 / 520	3,800,000		284 Operating	2002	Petcoke / Power	
Linna Energy Co./Global Energy, Inc.	Lima, OH	2/ 0 E-GAS (Destec/Dow)	910 / 727	7,357,000		549 Engineering	2006	Petcoke / Power	
WMPI Pty., LLC	Gilberton, PA	2/ 0 Shell	684 / 547	4,000,000		299 Engineering	2006	Coal / FT liquids	
Total Gasifiers in United States in 22 Projects		47/ 5	10,119 / 7,970	60,228,759		4,496			
Total Gasifiers in North America in 23 Projects		50/ 5	11,370 / 8,996	67,728,759		5,056			
Western Europe									
Finland									
Kemira Chemicals Oy	Oulu	1/ 0 Shell	50 / 41	300,000		22 Operating	1965	Petroleum / Chemicals	
Oy W. Schauman Ab Mills	Pietarsaari	1/ 0 FW ACFBG	35 / 28	204,819		15 Operating	1983	Biomass/Waste / Chemicals	
Norrsundet Bruks Ab	Norrsundet	1/ 0 FW ACFBG	25 / 20	146,299		11 Operating	1984	Biomass/Waste / Chemicals	
Lahden Lämpövoima Oy	Lahti	1/ 0 FW ACFBG	60 / 48	351,118		26 Operating	1998	Biomass/Waste / Power	
Corenso United Oy Ltd.	Varkaus	1/ 0 FW ACFBG	40 / 32	234,133		17 Operating	2001	Biomass/Waste / Chemicals	
Total Gasifiers in Finland in 5 Projects		5/ 0	210 / 169	1,236,369		92			
Former Yugoslavia									
Fabrika Azotnih Jendinjnja	Gorazde	1/ 0 LP Winkler	21 / 16	120,000		9 Operating	1952	Coal / Chemicals	
MSK-Radna	Kikinda	1/ 0 GE (Texaco)	248 / 211	1,540,000		115 Operating	1987	Gas / Chemicals	
Total Gasifiers in Former Yugoslavia in 2 Projects		2/ 0	268 / 227	1,660,000		124			
France									
Unspecified owner	Unspecified location	1/ 0 GE (Texaco)	72 / 62	450,000		34 Operating	1963	Gas / Chemicals	
Unspecified owner	Unspecified location	1/ 0 GE (Texaco)	97 / 82	600,000		45 Operating	1976	Gas / Chemicals	
Oxochimie S.A.	Lavéra	1/ 0 GE (Texaco)	99 / 81	590,976		44 Operating	1977	Gas / Chemicals	
Air Liquide (Rhône-Poulenc)	Pont-de-Claix	1/ 0 GE (Texaco)	45 / 38	278,000		21 Operating	1989	Gas / Chemicals	
Total Gasifiers in France in 4 Projects		4/ 0	312 / 262	1,918,976		143			
Germany									
Sekundärrohstoff-Verwertungszentrum	Schwarze Pumpe GmbH	Lausitz, Schwarze Pumpe	494 / 410	3,000,000		224 Operating	1964	Biomass/Waste / Power	
BASF AG	Ludwigshafen	1/ 0 GE (Texaco)	167 / 137	1,000,000		75 Operating	1966	Petroleum / Chemicals	
Chemische Werke Hüls AG	Marl	1/ 0 GE (Texaco)	100 / 82	600,000		45 Operating	1967	Petroleum / Chemicals	
BASF AG	Ludwigshafen	3/ 1 GE (Texaco)	167 / 134	980,208		73 Operating	1968	Petroleum / Chemicals	
Sekundärrohstoff-Verwertungszentrum	Schwarze Pumpe GmbH	Lausitz, Schwarze Pumpe	246 / 197	1,440,000		107 Operating	1968	Petroleum / Power	
Chemische Werke Hüls AG	Marl	1/ 0 GE (Texaco)	100 / 82	600,000		45 Operating	1969	Petroleum / Chemicals	
DEA Mineraloel AG	Wesseling	2/ 0 Shell	217 / 178	1,300,000		97 Operating	1969	Petroleum / Chemicals	
Veba Oil Refining & Petrochemicals GmbH	Gelsenkirchen	4/ 0 Shell	717 / 588	4,300,000		321 Operating	1973	Petroleum / Chemicals	

Gasifier Plant Owner	Location	No. of Gasifiers Operating/Spare Gas'n	Tech.	MWth		Syngas Cap., Eq. IGCC Nm3/d Cap., MW _e Status	Year	Feed Class / Product Category
				Fuel Input/SG Out	Cap., MW _e			
BASF AG	Ludwigshafen	4/ 0	GE (Texaco)	417 /	342	2,500,000	187 Operating	1974 Petroleum / Chemicals
Celanese Chemical (Ruhrechemie)	Oberhausen-Holten	1/ 0	GE (Texaco)	160 /	131	960,000	72 Operating	1977 Petroleum / Chemicals
Hydro-Agri Brunsbüttel GmbH	Brunsbüttel	4/ 0	Shell	803 /	643	4,700,000	351 Operating	1978 Petroleum / Chemicals
Mitteldeutsche Erdöl-Raffinerie GmbH	Leuna	6/ 0	Shell	1,163 /	984	7,200,000	537 Operating	1985 Petroleum / Chemicals
Rheinbraun	Ville	3/ 0	GE (Texaco)	381 /	305	2,231,500	167 Operating	1985 Coal / Chemicals
SAR GmbH	Oberhausen-Holten	1/ 0	GE (Texaco)	200 /	164	1,200,000	90 Operating	1986 Petroleum / Chemicals
Air Liquide (Dow Stede GmbH)	Stade	1/ 0	GE (Texaco)	43 /	36	264,000	20 Operating	1991 Gas / Chemicals
Sekundärrohstoff-Verwertungszentrum Pumpe GmbH	Lausitz, Schwarze Pumpe	1/ 0	CSP	234 /	164	1,200,000	90 Operating	1992 Petroleum / Power
Rüdersdorfer Zement GmbH	Rüdersdorf	1/ 0	Lurgi CFB	110 /	100	732,000	55 Operating	1996 Biomass/Waste / Gaseous fuels
Unspecified owner	Unspecified location	1/ 0	GE (Texaco)	250 /	205	1,500,000	112 Operating	1997 Petroleum / Chemicals
Sekundärrohstoff-Verwertungszentrum Pumpe GmbH	Lausitz, Schwarze Pumpe	1/ 0	BGL	195 /	156	1,138,000	85 Operating	1999 Biomass/Waste / Power
Unspecified Owner	Karlsruhe	3/ 0	ThermoSelect	43 /	34	250,000	19 Operating	1999 Biomass/Waste / Power
DEA Mineraloel AG	Wessling	1/ 0	GE (Texaco)	250 /	205	1,500,000	112 Operating	2000 Petroleum / Chemicals
Total Gasifiers in Germany in 21 Projects		48/ 1		6,456 /	5,276	38,595,708	2,881	
Italy								
Praxair (EniChem)	Ravenna	2/ 0	GE (Texaco)	113 /	96	700,000	52 Operating	1958 Gas / Chemicals
PRAOIL	Gela Ragusa	2/ 0	GE (Texaco)	185 /	157	1,150,000	86 Operating	1963 Gas / Chemicals
ISAB Energy	Priolo Gargallo, Sicily	2/ 0	GE (Texaco)	1,360 /	1,203	8,800,000	657 Operating	1999 Petroleum / Power
SARLUX srl	Sarrocchi, Cagliari, Sardinia	3/ 0	GE (Texaco)	1,586 /	1,271	10,400,000	776 Operating	2000 Petroleum / Power
api Energia S.p.A.	Falconara Marittima	2/ 0	GE (Texaco)	641 /	526	3,845,000	287 Operating	2001 Petroleum / Power
ENI SpA (AGIP Raffinazione SpA)	Sannazzaro	2/ 0	Shell	557 /	457	3,340,000	249 Construction	2005 Petroleum / Power
Total Gasifiers in Italy in 6 Projects		13/ 0		4,442 /	3,709	28,235,000	2,108	
Netherlands								
Nuon Power Buggenum	Haelen, Limburg	1/ 0	Shell	703 /	466	3,408,000	254 Operating	1994 Coal / Power
Shell Nederland Raffinaderij BV	Rotterdam	3/ 0	Shell	800 /	637	4,662,200	348 Operating	1997 Petroleum / Chemicals
EPZ	Geertruidenberg	1/ 0	Lurgi CFB	105 /	84	614,300	46 Operating	2000 Biomass/Waste / Power
Total Gasifiers in Netherlands in 3 Projects		5/ 0		1,607 /	1,187	8,684,500	648	
Portugal								
Sociedade Portuguesa de Petroquimica S.A.R.L.	Lisbon	3/ 0	GE (Texaco)	103 /	85	620,000	46 Operating	1961 Petroleum / Chemicals
Quimigal Adubos	Barreiro, Lavradio	2/ 0	Shell	400 /	328	2,400,000	179 Operating	1984 Petroleum / Chemicals
Portucel	Rodao	1/ 0	FW ACFBG	1.5 /	12	87,800	7 Operating	1985 Biomass/Waste / Chemicals
Total Gasifiers in Portugal in 3 Projects		6/ 0		519 /	425	3,107,800	232	
Spain								
Elcogas SA	Puertollano	1/ 0	PRENFLO	735 /	588	4,300,000	321 Operating	1997 Coal / Power
GE Plastics España	Cartagena	1/ 0	GE (Texaco)	26 /	22	160,800	12 Operating	1997 Gas / Chemicals
Total Gasifiers in Spain in 2 Projects		2/ 0		761 /	610	4,460,800	333	
Sweden								
Perstorp Oxo AB	Stenungsund	1/ 0	GE (Texaco)	33 /	27	200,000	15 Operating	1980 Petroleum / Chemicals
ASSI	Karlsborg Bruk	1/ 0	FW ACFBG	27 /	22	158,003	12 Operating	1984 Biomass/Waste / Chemicals
Sydskraft AB	Malmö/Värnamo	1/ 0	FW PCFBG	18 /	14	105,000	8 Operating	1993 Biomass/Waste / Power

Gasifier Plant Owner	Location	No. of Gasifiers Operating/Spare Gas'n Tech.	MWth Fuel Input/SG Out	Syngas Cap., Eq. IGCC Nm3/d Cap., MWc Status	Year	Feed Class / Product Category
Total Gasifiers in Sweden in 3 Projects						
United Kingdom		3/ 0	78 / 63	463,003	35	
Air Products (ICI)	Billingham, England	3/ 0 GE (Texaco)	97 / 82	600,000	45 Operating	1959 Gas / Chemicals
BP Chemicals, Ltd.	Hull, England	1/ 0 GE (Texaco)	147 / 125	910,900	68 Operating	1989 Gas / Chemicals
BASF plc	Middlesbrough, England	1/ 0 Noell	36 / 30	220,000	16 Operating	2000 Biomass/Waste / Chemicals
Total Gasifiers in United Kingdom in 3 Projects						
		5/ 0	279 / 237	1,730,900	129	
Total Gasifiers in Western Europe in 52 Projects						
		93/ 1	14,932 / 12,165	90,093,056	6,726	
Total Gasifiers in 138 Active-Real Projects						
		399/ 30	66,452 / 53,528	370,723,399	27,675	
Total All Gasifiers in 138 Projects						
		399/ 30	66,452 / 53,528	370,723,399	27,675	

Source: SFA Pacific, Inc.

Victorian Power and Liquids Project

Source: www.apel.com.au

Key Features

The key features of the Project are:

- brown coal resources (Loy Yang) typically 63% moisture, ash content 2% (db), GDSE (gross dry specific energy) 26 MJ/kg;
- the 3 billion tonne measured resource equates to over 2.6 billion barrels of sulphur free fuels;
- a long resource life (100 years +);
- Stage One (Phases 1 & 2) production of 70,900 bpd (capable of multiple expansions) equates to a feedstock rate of approximately 82,000 per day;
- availability of proven technology – preferred suppliers are Shell and RWE;
- low operating costs – circa US\$11.60 cash cost per barrel of refined product (diesel);
- reducing input costs in real terms over the project life;
- no material ongoing exploration costs;
- vertical integration potential for future value added product streams.
- a proposed US\$4.1 billion phased integrated energy and infrastructure project capable of multiple expansions whilst minimising technical and economic risk because of the phased approach, Phase 1 first train of US\$632 million equates to capital investment of approximately \$US58,000 per daily barrel;
- the production of two valuable resources, i.e. low sulphur fuels and/or electricity;
- significantly reduced carbon dioxide (CO₂) emissions;
- oil pipeline and power transmission infrastructure are in place;
- capacity for 3,000 MW plus on an optional electricity basis (in lieu of fuels production) equates to capital investment cost of approximately US\$1400 per kW_e capacity;
- globally transferable technology utilization.

Project Highlights

- The Feasibility Study confirms the potential to develop the Victorian Power and Liquids Project as an economically robust, long life, very substantive cash flow coal-to-gas-to-liquids development.
- The readily mineable coal resource of 3.0 billion tonnes contained within the Flynn Field is equivalent to 2.6 billion barrels of ultra high quality oil (mainly diesel), with a total of 17.8 billion tonnes within the EL area calculated to JORC standards. The latter number equates to 16 billion barrels.
- A recommended initial two phase project development approach has been assessed that mitigates the technical and commercial risks for the initial development. The first phase is a nominal 10,000 bpd plant followed by a 60,000+ bpd second phase.
- This 3 billion tonne resource is sufficient to support two full scale VPLP coal to liquids project with the capacity to grow production to approximately 150,000 bpd through successive investment phases, progressive debottlenecking and plant enhancement.
- By incorporating the long term disposal of carbon dioxide in the depleted reservoirs and deep saline aquifers of the Gippsland Sedimentary Basin (geosequestration) the project will meet Government and community expectations to assist in solving the challenge of global warming.
- The main product, Fischer Tropsch diesel, represents the highest quality diesel possible to manufacture and exceeds all likely future environmental and technical quality requirements.

with steam from the gasification process and Fischer-Tropsch reactor, can be fed to a Heat Recovery Steam Generator (HRSG). The steam raised can be used to drive steam turbines for power generation.

- 12 Water is recycled and reused in the plant to reduce raw water intake. Water treatment systems include cooling water for clean and process water, a boiler feed water system, a desalination plant and an activated sludge plant.

Geosequestration — What is it?

It is considered that the vast amount of carbon dioxide pumped into the atmosphere by burning fossil fuels such as coal, natural gas and oil may contribute to global warming. One approach to mitigating climate change is to find ways to reduce carbon dioxide emissions into the atmosphere. Carbon sequestration is the capture and storage of carbon dioxide that would otherwise be emitted to the atmosphere. The captured carbon dioxide can be stored in underground reservoirs, converted to rock-like solid materials, or adsorbed by trees, grasses, soils or algae. The term geological sequestration or geosequestration is used where the carbon dioxide is injected into a deep geological structure for storage.

In preparation for geosequestration carbon dioxide is compressed to the point where it is in the super critical state. In this state carbon dioxide has a density similar to a very light liquid, such as petrol, and a viscosity similar to gas. This compression occurs at the processing plant site prior to transport to the geosequestration site via a high pressure pipeline similar to high pressure natural gas transmission pipeline.

Wells drilled deep into the storage reservoir are used for injection of the carbon dioxide. The reservoir is a layer of permeable rock that has a thick layer of impermeable rock or seal above it. A site is chosen after extensive studies to ensure the site has sufficient capacity for the carbon dioxide to be injected over many years and a geological seal that prevents the carbon dioxide from rising above a certain depth.

Such reservoirs are the same type of geological formation that have trapped crude oil and natural gas over millions of years. Over long time periods a large proportion of the carbon dioxide dissolves in the saline water in the reservoir and a smaller proportion combines chemically with minerals in the rock structure.



Photo montage of conceptual large-scale brown coal gasification to power and liquids facility

Appendix 2

Selected Lignite Deposit Characteristics

summarised from

Lignite as a Source of Transport Fuels in New Zealand

Report No. LF2028, Liquid Fuels Trust Board, May 1983

Prepared by: Bruce Riddolls

Location and Topography of the Deposits

The Hawkdun deposit is located in Maniototo County at the head of the Manuherikia River valley (Figure A.1). The area is sparsely settled with the township of Alexandra 65 km to the southwest. The deposit lies beneath flat land which is covered mainly by unimproved pasture and tussock bounded by the Hawkdun range in the northeast and the St Bathans Range to the west. Large-scale irrigation of the Manuherikia Valley began with the construction of the Falls Dam in 1935. River flows in the region are severely restricted during the summer since available water is totally committed for irrigation and stock water requirements. In periods of heavy rain considerable quantities of debris, including boulders, are carried down the river. The Upper Manuherikia provides trout spawning waters and is a game habitat. Little information is available about groundwater conditions, however, some artesian flows have been encountered during drilling operations.

Ashers-Waituna is located on, or at the northern edges of, the Awarua Plain (Figure A.2). The deposit lies beneath flat, low terraces and flood plains crossed by several small streams and gullies. The lower reaches of the Mataura River lie along the eastern edge of the coal area. Peat swamps cover much of the Ashers-Waituna deposit. In general, the land is rural and is intensively farmed for wool and meat. Some land is developed for forage cropping but very low-lying land is undeveloped.

The peatlands and bush remnants in the area form important native bird habitats and the Waituna region is an internationally recognised, and gazetted, wetland reserve. This area contains predominantly shallow waters and mud flats with land areas above the Ashers-Waituna deposit draining into a lagoon.

The local climate is wet with temperate summers and cold winters and the area is unprotected from the prevailing westerly winds, being located close to the sea.

Resource Characteristics

General

The vertical stratigraphy of the Central Otago and Southland lignite fields is depicted schematically in Figure A.3.

The Central Otago deposits, which include Hawkdun, are present within the Manuherikia Group and are of Miocene age. This group consists of a thick widespread unit of fluvial (river-produced), lacustrine (lake-produced), and swamp deposits now preserved in a series of block-faulted basins aligned north to northeast.

The lignite deposits occur within these fault-controlled basins. Known or suspected faults delineate most boundaries of the deposits and are also likely to be present within the proposed mining areas (Bowman 1980; 1981; Bishop, 1981; Dr Otto Gold, 1981a; 1981b; 1981c; Isaac, 1981a; Turnbull, 1981). Seam dips are typically gentle to moderate.

The Manuherikia Group unconformably overlies basement rock (i.e. localised discontinuities occur in the stratigraphic sequence so that, in some places the seams rest directly on the basement rock). In many places the upper sections of the sequence have been eroded and replaced by localised beds of sand and gravel. These so-called paleowashout channels are often aquifers and can give rise to mining problems.

The greywacke and schist basement rocks are of Permian to Jurassic age and are weathered to considerable depths.

The material overlying the Central Otago lignite deposits consists of Quaternary gravels varying in depth up to 55 m. These gravels contain boulders up to 1 m in diameter and are generally covered by a thin layer of loess (fine, wind deposited soil materials).

Only limited groundwater information is available and the groundwater hydrology has largely been inferred from the known geological characteristics. The geology of the Central Otago deposits is such that few aquifers are expected within the coal-bearing sequence itself although extensive subsurface

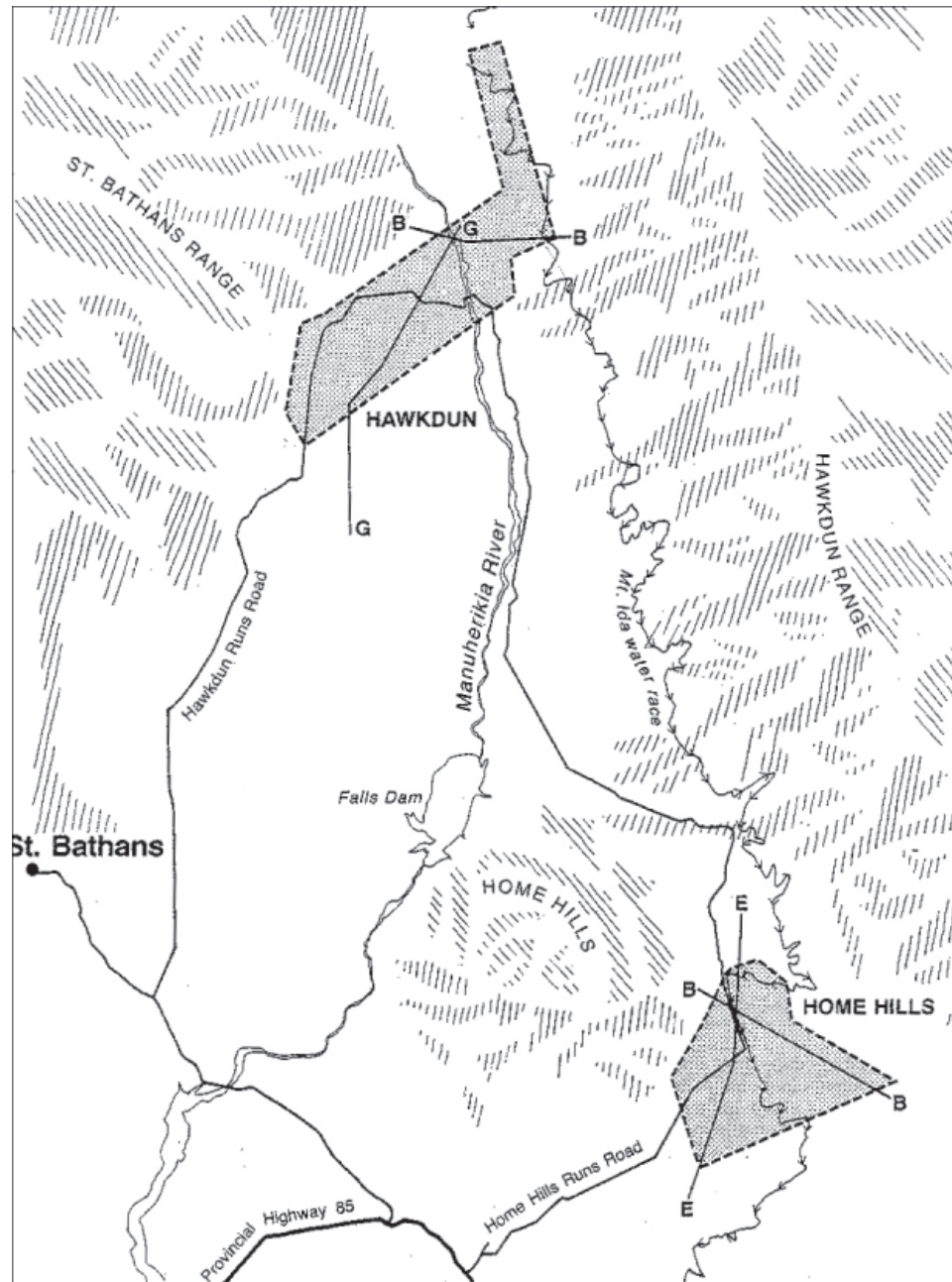


Figure A1: Location of the Hawkdun and Home Hills deposits (locations of cross sections indicated); LFTB Fig 2.10

investigations will be required to delineate zones of coarse grained material which are potentially water-bearing.

The Southland deposits, which include Ashers-Waituna, are present within the Gore Lignite Measures and are of Oligocene to Miocene age. These measures, which unconformably overlie the basement rock, consist of a non-marine succession of clay, silt, sand and gravel, and lignite seams. Marine beds of the Chatton Marine Formation are interspersed with the lower lignite seams in some parts.

The structure of Ashers-Waituna is relatively simple. Seams are either horizontal or dip gently and faulting is not apparent.

Various gravel deposits, including the Waimumu Quartz Gravels (mid Tertiary), Gore Piedmont Gravels (late

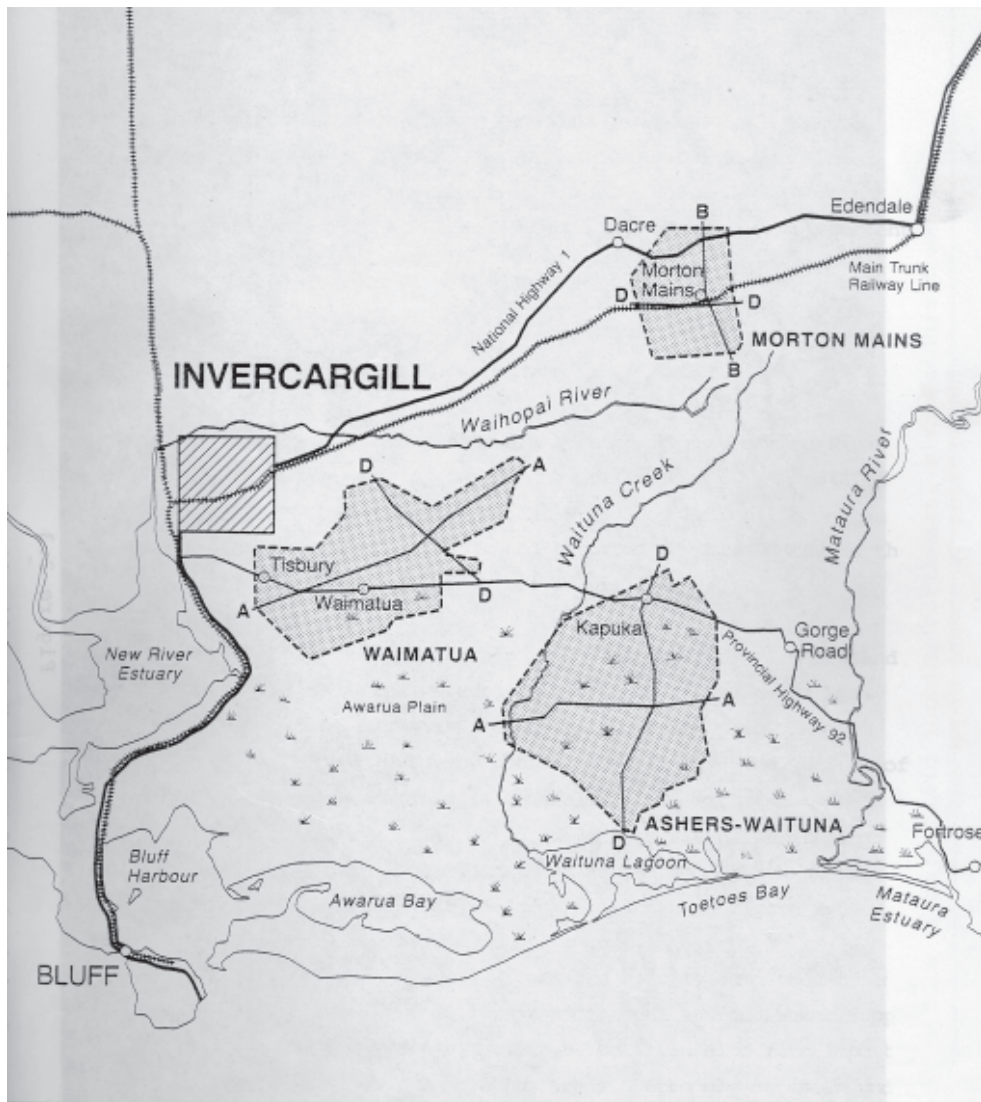


Figure A.2: Location of the Ashers -Waituna deposit (locations of cross sections indicated); LFTB Fig 2.2

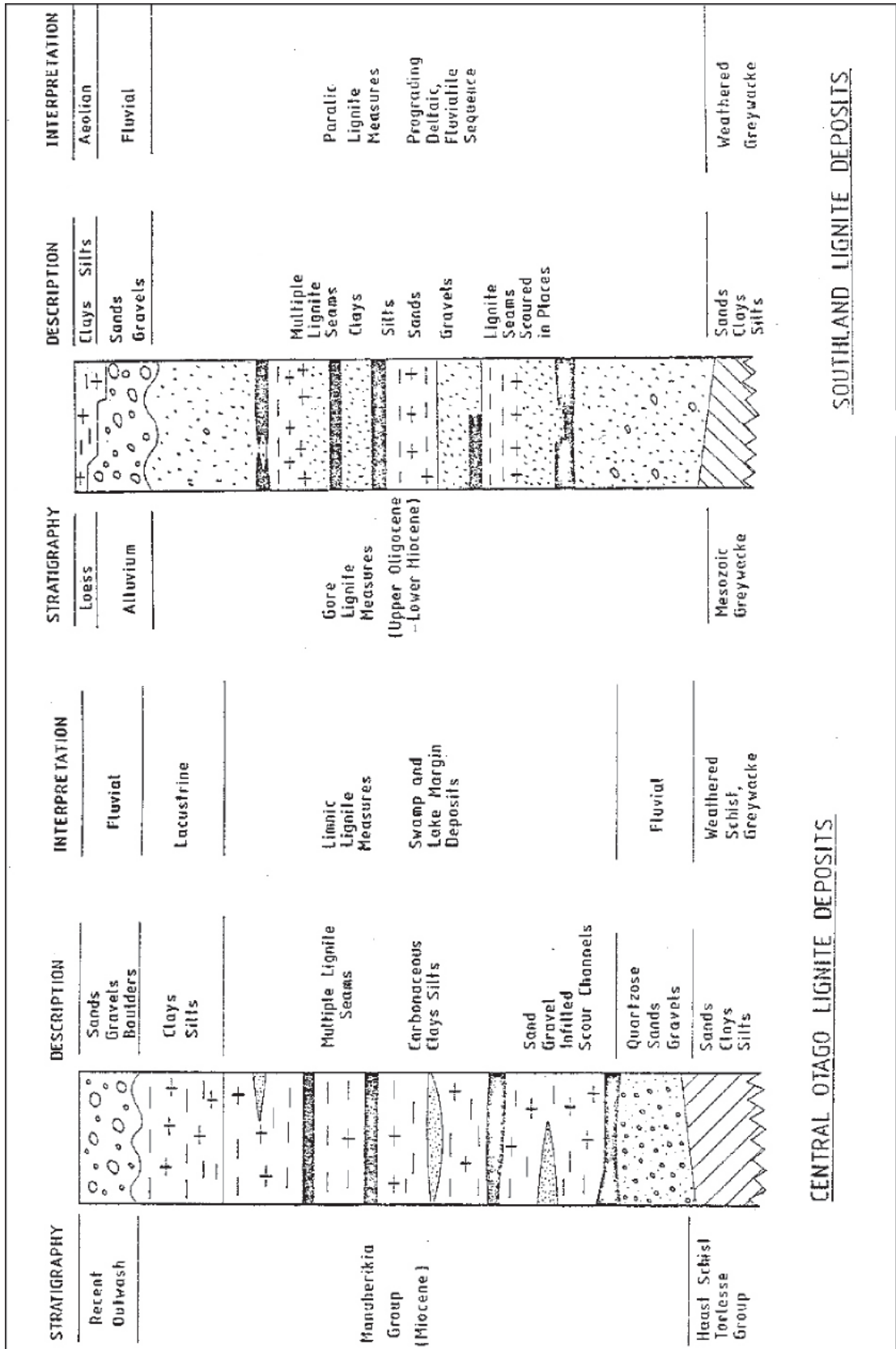
Tertiary to Pleistocene) and more recent alluvial and marine gravels, overlie the Southland lignite deposits in most places. There are generally covered by a layer of loess up to 6 m thick.

The geology of the Southland deposits indicates the presence of a sequence of discrete, laterally persistent, coarse and fine grained sediments interbedded with the lignite seams. These are likely to be aquifers. Lowering of the watertable surrounding the Ashers-Waituna deposit could cause sea water to infiltrate the fresh water aquifers close to the coast.

Hawkdun

A cross-sectional representation of the Hawkdun lignite deposit is presented in Figure A.4. To date 14 boreholes define the deposit that covers an area of 16 km². The deposit is currently described in two parts – the Hawkdun to the northeast and the Manuhierikia to the southwest. These have maximum depths of 280 and 200 m, respectively.

The seams of the deposit are generally thin and highly variable, although when aggregated give some significant coal thicknesses. The deposit is dominated by the Hawkdun seam which has a maximum



CENTRAL OTAGO LIGNITE DEPOSITS

SOUTHLAND LIGNITE DEPOSITS

Figure A.3: Schematic Summary of vertical wall stratigraphy (not to scale);
LFTB Fig 2.12

aggregated thickness of 91 meters (including 20 meters of mudstone partings) subdivided into 8 major splits.

Major faults determine the configuration of the deposit. Thus, the Hawkdun area is between the Hawkdun no.1 and Hawkdun no.2 faults. Two other fault systems (St Bathans and Manuherikia) form the western boundary of the Manuherikia. However, considerable structural uncertainty still exists. Extension of the lignite area of the south of the Manuherikia is a possibility at depth.

Materials overlying the deposit consist of Quaternary gravels containing boulders up to 1 m in diameter. These provide only a thin cover (up to 10 m). Between the surface gravels and the lignite-bearing strata there is a layer of weakly consolidated fine-grained clastic (fragments of older rocks) materials that are expected to cause problems of rock instability.

Known and suspected faults are present within the deposit boundaries and these may cause mining problems due to disturbed seams and the ingress of groundwater along faults. The large catchment area and steep topography may mean that extensive water retention damming and diversion canal construction would be required for mine development. The Manuherikia River would also need to be diverted from the mine area.

Ashers-Waituna

A cross-sectional representation of the Ashers-Waituna lignite deposit is presented in Figure A.5. To date 39 boreholes define the deposit which covers an area of 70 km² and reaches a maximum depth of 120 m. Seven seams have been identified within the 60 to 80 m thick lignite-bearing interval of the Gore Lignite Measures, but most of the lignite is present in two shallow, level seams with an aggregate thickness of between 15 and 20 m.

The deposit is undisturbed by major structural faults and the lignite seams dip gently at about 1° in a southwesterly direction. Occasional greater dip angles ($\leq 4^\circ$) are encountered in parts of the deposit. Depositional thinning and splitting of the seams occurs. The western boundary has been arbitrarily assigned and possible extension of the deposit to the west has yet to be confirmed.

Material overlaying the lignite measures consists of coarse gravel covered by loess. Similar clastic material together with fine sand is interbedded with the lignite.

The high proportion of fine sand is likely to provide relatively unfavourable conditions for the development of stable waste dump due to its susceptibility to water erosion. For the same reason pitwall stability would require the effective interception and removal of large quantities of water.

In places the lignite seams have been eroded and replaced by sand and gravel-filled paleowashout channels which, due to the presence of both fine- and coarse-grained material, may act as either aquifers or aquicludes. Consequently the hydrological regime is likely to consist of multiple aquifers and aquicludes interspersed between the lignite seams. The aquifers are expected to be hydraulically connected in all directions.

Static groundwater levels are at, or close to, the surface and the water table is contained within the surface gravels. These are free draining and their dewatering should be straightforward. However, the high static groundwater level and the presence of artesian pressures would require removal of water located both around and inside the perimeter of the mine before development could begin.

Reserves

The close proximity of the Ashers-Waituna deposit to the coast could result in the infiltration of aquifers by sea water if the water table surrounding the mine were lowered. This possibility needs to be rigorously investigated prior to development of firm mining plans.

Various criteria can be employed to define levels of coal availability and coal quantities. For the lignite studies two estimating categories are used:

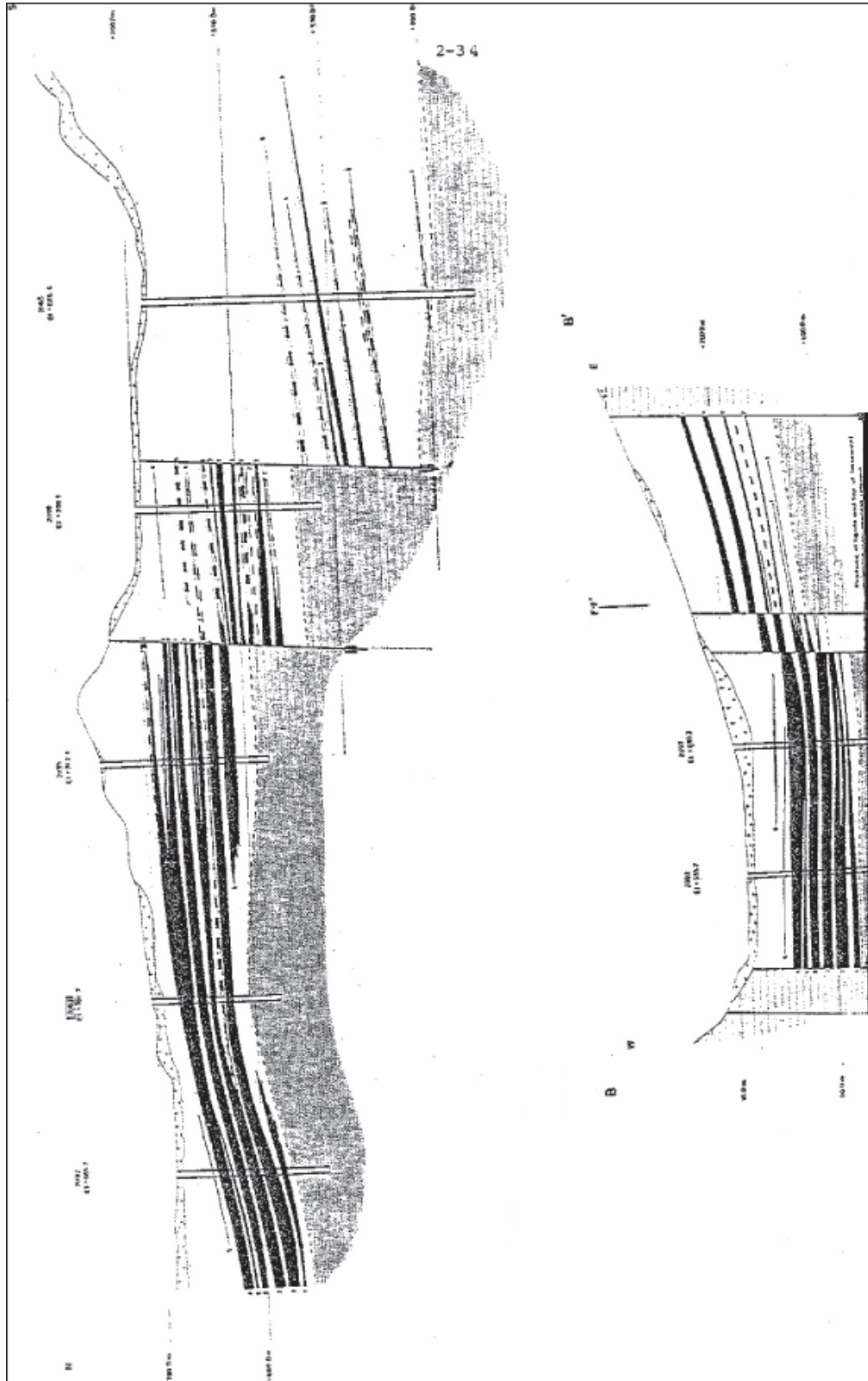


Figure A.4: Cross section of the Hawkdun deposit. (see Figure II.1 for location). Borehole locations and numbers as indicated; LFTB Fig 2.15

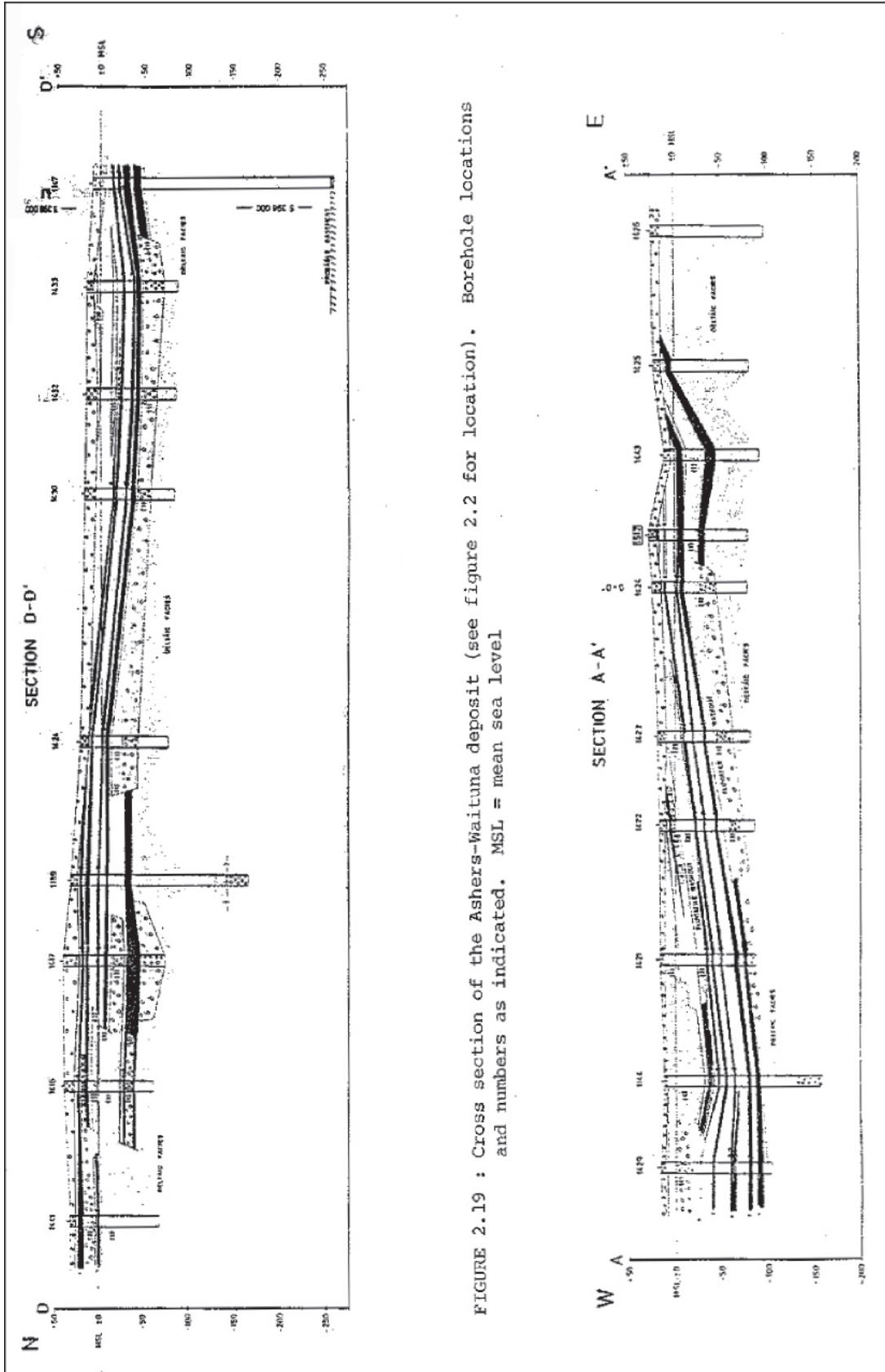


FIGURE 2.19 : Cross section of the Ashers-Waituna deposit (see figure 2.2 for location). Borehole locations and numbers as indicated. MSL = mean sea level

Figure A.5: Cross section of the Ashers-Waituna deposit (see figure 11.2 for location). Borehole locations and numbers as indicated. MSL = mean sea level; LFTB Fig 2/19

- coalfield resource; and
- technically recoverable reserve.

The definition of each is as follows.

Coalfield Resource: constitutes the total tonnage of lignite present in the ground in a defined deposit. The deposit is defined on the basis that it is sufficiently distinguishable from surrounding lignite deposits to warrant a separate estimate. Standard criteria are assigned to delineate the lignite material.

Technically Recoverable Reserve: constitutes the tonnage which can be economically recovered within the limits of present, or immediate future, mining technology. The quality of the lignite is taken into account in determining seams worth recovering and account is also taken of losses during mining. Accordingly estimates of coal quantity are based on cut-off criteria assigned to the amounts of waste, including allowance for batters, removed during mining, workable seam thicknesses and lignite quality.

Each of these estimates can be subdivided according to the quality of the lignite resource data upon which they are based. In the present studies three levels of accuracy have been considered in defining the lignite resource (Bowen, 1978).

- 1 Measured Lignite** is that for which the tonnage is computed from dimensions revealed in outcrops, trenches, workings and drillholes, and for which the ash content is computed from the results of detailed sampling. The geologic character of the coal area is so well defined that the size and shape of the deposit can be established within stated limits.
- 2 Indicated Lignite** is that for which the tonnage and ash content are computed partly from specific measurements, samples, or production data, and partly from projections based on geological evidence.
- 3 Inferred Lignite** is that for which the quantitative estimates are based largely on a broad knowledge of the geological character of the deposit and for which there are fewer samples or measurements than required to place the deposit in a higher category. The estimates are based on an assumed continuity or repetition for which there is geological evidence; this evidence may include comparison with other deposits of similar type.

Estimates of the coalfield resources in the nine South Island lignite deposits have been made by the New Zealand Geological Survey. Lignite present in seams and splits less than 1 m thick, of more than 20% ash (dry basis), or deeper than 300 m is excluded from the estimate.

Estimates of the technically recoverable reserves have been made by Dr Otto Gold Consulting Engineers (Otto Gold, 1982). These assume that:

Technically Recoverable Reserve = Coalfield Resource MINUS:

- 1 Lignite present in insufficiently investigated area.
- 2 Lignite in structurally complex or highly disturbed areas.
- 3 Lignite of inferior quality due to poor structure, washouts, burnouts, or surface oxidation.
- 4 Lignite having an ash (mineral matter) content greater than 15 percent.
- 5 Lignite having a waste:coal ratio greater than 7.5:1 (cubic meters:tonnes) and including overburden lignite with an ash content above 15 percent and a thickness less than 0.75 m, but excluding the effect of batters.
- 6 Lignite present in seams of thickness less than 0.75 m.
- 7 Lignite not considered to be economically mineable due to unfavourable deposit configurations.

The Technically Recoverable Reserves were calculated assuming a 7 percent loss during mining to take into account the necessary slope angles required for open cut mining. The 7 percent loss figure is based on experience of comparable lignite mining operations overseas.

The reserve estimates are based on lignite resource data with an assigned accuracy of indicated or better.

The Coalfield Resources and Technically Recoverable Reserves for nine South Island lignite deposits studies are presented in Table A.1.

Coal Quality

Proximate analyses of coal quality have been carried out, consisting of a series of physical and chemical analyses designed to quantify those factors which are of primary interest in process engineering. The results can be used to predict the suitability of a coal to different process technologies and its probable behaviour under different conversion conditions.

Proximate analyses for several samples of lignite are presented in Table A.2. The data show that Ashers - Waituna lignite is of slightly lower rank than Hawkdun in that it has higher moisture content, and lower volatile matter, fixed carbon, and specific energy content.

Mining

General

It is accepted that open cast mining is the most appropriate method for recovering the South Island lignites. This is because it enables the use of large scale equipment and is much less labour intensive and more cost effective than underground mining. The major constraint on the development of an open cast mine is its depth and the amounts of overburden and interburden (between seams) which must be removed, stored, and replaced. All of the South Island lignite deposits are, however, amenable to open cast mining.

Initially, topsoil and overburden are removed and placed in an outside dump. The mine is then developed in a series of terraces or benches so as to expose a leading edge along which excavation proceeds.

When the mine reaches its planned depth and opened sufficiently, waste material is dumped inside the mined section and backfilled behind the lignite face. In this way only a portion of the mineable area is uncovered at any one time and restoration can proceed at the same time as lignite recovery. Topsoil is recovered and used in reclaiming the dumps.

The use of bucket wheel excavators in conjunction with belt wagons, conveyers, tripper cars and spreaders is the preferred method for lignite mining on the scales envisaged.

Due to the limited exploration to date the Hawkdun lignite reserve is classified as "poor indicated".

From a mining standpoint the presence of interburden clays with swelling characteristics and the microtectonic pattern could modify the planning and execution of an opencast mine. Also, the degree to which hydrological problems can be expected is largely untested although the presence of artesian groundwater pressure is expected. This can have a substantial effect on the stability of mine slopes and the pit floor. Further exploration is clearly required in order to assess these factors.

The Ashers-Waituna deposit covers a large area (approximately 70 km²) and has not been closely drilled so that its reserve is classified in the "poor indicated" category. The close proximity of Ashers-Waituna deposit to the coast could result in the infiltration of aquifers by sea water if the water table surrounding the mine were lowered. This possibility needs to be rigorously investigated prior to development of firm mining plans.

Environmental Issues

Both the lignite mining and processing operations could give rise to adverse effects on the local and regional environment. Such effects can be classified in terms of:

- air pollution
- water pollution, and ground and surface water disruption

DEPOSIT	Total Coalfield Resource (1)				Technically Recoverable Reserves (2)			
	Measured	Indicated	Inferred	Total coal In-ground	Measured plus Indicated Coal	Average Ash %	% Recovery Factor	
Hawkdun	-	550	262	812	475	8.6	58.5	
Home Hills	-	282	64	346	246	6.0	71.1	
Roxburgh	-	197	48	245	132	8.1	53.9	
Croydon	-	435	49	484	309	8.8	63.8	
Waimumu	-	251	35	286	217	6.9	75.8	
Mataura	1634	791	516	2940	1808	8.2	61.5	
Morton Mains	-	755	471	1226	507	9.0	41.3	
Ashers Waituna	-	1283	74	1357	872	7.0	64.3	
Waimatua	-	962	-	962	775	5.6	80.6	
TOTALS				8658	5341			

Table A.1: Reserve estimates (million tonnes) for the South Island lignites (LFTB Table 2.1).
Sources: (1) NZ Geological Survey, (2) Dr Otto Gold Consulting

- aesthetic effects
- noise pollution

Five main areas of potential environmental concern are associated with the actually lignite mining operation. These are:

- 1 Generation of dust
- 2 Release of contaminated water into the surrounding ground and surface waters

Deposit	No. Bore Holes Analysed (seams)	Mean Analysis (Bed Moist basis) %							Hardgrove* Grindability	Classification
		Moisture	Ash	Volatile Matter	Fixed Carbon	Specific Energy (MJ/kg)	Sulphur			
Home Hills	3 (10)	51.8	6.5	23.2	18.5	11.10	0.33	77.3 ± 60	Lignite B	
Hawkdun	2 (5)	47.9	9.5	24.9	17.7	11.31	0.40	47.1 ± 30	Lignite B	
Roxburgh	5 (1)	49.6	4.5	28.2	17.7	12.71	0.4	46.9 ± 12	Lignite B	
Waimumu	38 (11)	42.3	5.2	29.3	23.2	14.04	0.5	33.1 ± 9	Lignite A	
Croydon	9 (7)	40.7	9.8	28.6	20.9	12.98	0.6	31.8 ± 9	Lignite B	
Mataura	23 (10)	46.4	6.4	24.9	22.3	12.68	0.5	38.7 ± 19	Lignite B	
Morton Mains	6 (5)	60.6	6.4	19.1	13.9	8.57	0.15	53.9 ± 25	Lignite B	
Ashers Waituna	13 (5)	54.9	4.9	23.0	17.2	10.48	0.5	50.8 ± 25	Lignite B	
Waimatua	19 (5)	57.1	5.3	21.6	16.0	9.72	0.14	54.9 ± 20	Lignite B	

* Based on tests designed for black coals and thus shows extreme variability because of the non-uniformity of the coal material. These figures cannot be considered a true guide to grindability.

Table A.2: Proximate analyses South island Lignites
(LFTB Table 4.3)

- 3 Lowering of the water table beyond the mine limits due to mine de-watering operations
- 4 Generation of large amounts of solid waste
- 5 Creation of an aesthetically undesirable landscape.

Environmental pollution associated with the conversion plant and its associated offsites and infrastructure would consist of atmospheric emissions, liquid effluents, and solid wastes.

Although the conversion processes being considered differ considerably in their technology and in their immediate and final products, there is a notable similarity in the general characteristics of the pollutants produced. This is because all are derived from the elements Hydrogen, Carbon, Oxygen, Sulphur and Nitrogen, which have been subjected to stringent reducing conditions or from mineral matter in the lignite.

Water supply

The main uses of water in a liquid fuels conversion facility are for:

- mine operation, for dust control, fire control etc
- input as chemical feed to the conversion process
- boiler feed water for steam raising
- cooling water
- effluent dilution
- settlement water supply

Potential water supplies could come from surface water (rivers) or from groundwater available from the mining operation. Preliminary assessment of the regional water balances, however, indicates that groundwater would be insufficient to meet the demands in all cases (Ashworth-Morrison and Cooper, 1982). This assessment is, however, based on an inadequate knowledge of the hydrological conditions associated with each deposit and quantitative estimates of groundwater availability require the conduct of extensive hydrological investigations.

In general, the groundwater resources in Central Otago are substantially less per square kilometre of catchment area than those in Southland. This is because in Central Otago, the precipitation is lower, the evaporation rate higher, and the water holding capacity of the soils lower than in Southland.

Water storage possibilities are, however, more extensive in Central Otago than in Southland. Thus, the Hawkdun deposit is in the centre of proposed local irrigation schemes so that storage capacity is likely to be available and the design of water reservoirs reasonably straightforward. (It should be noted that storage of water at Hawkdun would be necessary to maintain supplies throughout drought periods). By comparison the dam potential at Ashers-Waituna site is minimal.

In order to illustrate the types of water supply situations likely to exist in Central Otago and in Southland a more detailed assessment has been made of the representative locations at Hawkdun and Ashers-Waituna. These show that the most feasible water source for a plan at Ashers-Waituna is the Mataura River. Water would need to be pumped from an intake structure, sited upstream of tidal influence, to storage facilities having two days capacity. Additional pumping would be required to achieve a reasonable reticulation pressure. The Invercargill city water supply is, however, considered capable of meeting settlement requirements without major upgrading.

Preliminary studies of water supply at Hawkdun indicate that the Manuherikia River could provide all the plant requirements in addition to possible future irrigation demands, although storage at the diversion dam would be required. Water would need to be pumped from the diversion dams then piping to a storage reservoir having two days capacity. It would then be fed by a gravity pipeline to the plant. The Manuherikia River could not accommodate settlement water supplies on top of plant supply and future

irrigation demands, however, so that additional supplies would be required.

It is apparent from the foregoing remarks that, while water supplies are available at the locations considered, more detailed information about surface and groundwater flows and quality is required. In particular, it should be noted that a lignite conversion facility may have to compete for water with other local users especially in Central Otago.

Appendix 3

Carbon Capture and Sequestration

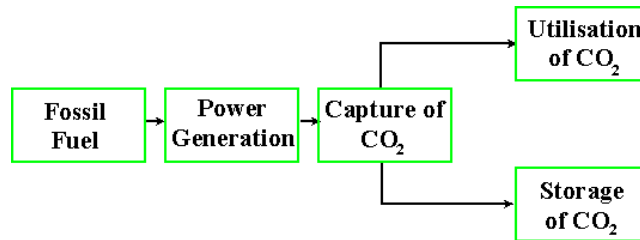
taken from

IEA Greenhouse Gas R&D Programme

(www.ieagreen.org.uk)

Capture and Storage of CO₂

The main steps in the process of capture and storage of CO₂ are shown in the figure below for a conventional fossil-fuel fired power plant. After the fossil fuel has been burnt to produce power, the CO₂ is separated from the flue gas stream. Then the CO₂ would be stored, for a long time, if it cannot be put to some useful purpose.



The technology of capture is in use today supplying CO₂ to the food industry and for other purposes. Studies of a number of different types of separation process have been conducted by the IEA GHG Programme; these cover the common types of power plant: natural gas combined-cycle and pulverized coal plant, as well as possible future plant including coal gasification combined cycles and fuel cells; 3 representative fuels have been considered: natural gas, coal and, to a lesser extent, Orimulsion. A wide range of CO₂ storage and utilisation options have also been assessed.

Hydrogen is often promoted as a “clean” energy carrier, usually with the assumption that it will be obtained from a renewable source of energy. Capture and storage of CO₂ could be used to produce hydrogen from fossil fuels with minimal emissions of CO₂. In this way, hydrogen could introduced as an energy carrier, without the additional disruption which would arise from a major change in the source of energy.

Understanding the impact that any of these systems makes requires life-cycle analysis; combining this with cost-benefit analysis provides a method of evaluating the global impact of such systems. IEA GHG has developed a method for analysing the full fuel cycle of systems incorporating capture and disposal of CO₂.

Many of these studies indicate areas where further practical research, development or demonstration (R,D&D) is needed. The IEA GHG Programme is helping the formation of collaborations to undertake practical R,D&D in areas of interest.

Power Generation

The power generation sector is a major source of CO₂ emissions world-wide. Studies by the IEA GHG Programme have established cost, efficiency and emissions data for a representative range of power stations, including both current and future technology. These provide the base cases for studies of CO₂ capture and storage. The likelihood of further technical developments in each of the main types of plant has also been examined. To ensure consistency, a common set of financial and technical conventions provide the basis for these assessments. The performance of each type of plant is assessed with and without capture of CO₂ from the flue gases.

Types of power plant studied include:

- Pulverized (coal) fuel with flue gas desulphurisation, representing the most commonly used type of plant; this provides a marker against which other power generation technologies can be compared. The plant uses steam at sub-critical conditions but the impact of more recent super-critical steam cycles is also considered. Variants include enhanced removal of “acid gases” (e.g. SO₂ and NO_x).
- Natural gas-fired combined-cycle generation which is another widely available technology; in this case, natural gas is burnt in a gas turbine operated in conjunction with a steam turbine to improve overall efficiency. This is the most efficient option studied, emits the least amount of CO₂ (per kWh)

generated) and, with low cost supplies of gas, is the cheapest means of generating electricity.

- Integrated gasification combined-cycle (IGCC), a representative of emerging technology, appropriate for a future when CO₂ mitigation is practised. The base case involves a coal-slurry fed gasifier; many variations are also evaluated, including the type of gasifier and conversion of the carbon monoxide in the gasifier's output to CO₂.
- Combustion of coal in an atmosphere of oxygen and recycled CO₂, a potential option for the longer-term. Schemes of this type have been suggested because they raise the concentration of CO₂ in the exhaust gas, thereby making capture easier.
- Air-blown gasification of coal is promoted as a more efficient process than oxygen-blown gasification (IGCC). However, when combined with a requirement to capture CO₂, it was found that air-blown gasification is more expensive than IGCC. For similar levels of technology development, if CO₂ capture is to be used, IGCC would be preferred.
- Fuel cells are another low emission technology. There are many possible types of fuel cell so, from an initial survey, IEA GHG selected one type, the molten carbonate fuel cell, for investigation as a possible large-scale power plant with CO₂ removal. When compared with more conventional plant (both using CO₂ removal), the molten carbonate fuel cell showed no advantage.
- One example of a liquid hydrocarbon fuel has been studied - the heavy oil/water emulsion known as Orimulsion. As well as electricity production, methanol and hydrogen production were also considered in this study. This study was jointly funded by the IEA GHG Programme and Statoil. The cost penalty for capture of CO₂ is less for this system than for comparable coal-fired systems.

CO₂ Capture

Systems are already available for capturing CO₂ but there is only limited choice at present and so the technologies evaluated include a number still under development. Each capture technology is considered to be applied to the flue gas stream of each of the types of power plant described above. The main conclusions about the various capture options are:

- Adsorption of the gas by use of molecular sieves - a key aspect is how to release the gas after it has been captured; in all the cases studied, varying the pressure to release the gas is preferable to varying the temperature, because the adsorber can be freed of gas and put back into service faster. The removal of CO₂ by an adsorbent is most effective when the concentration in the flue gases lies between 400ppm and 1500ppm, lower than is normally the case with power stations; coupled with limited capacity and poor selectivity, this makes adsorption unattractive for CO₂ capture from power generation.
- Physical and chemical absorption - 3 solvents were evaluated for each of the base case power plants. For low concentrations of CO₂ in the flue gases, a chemical solvent such as monoethanolamine is preferred; where the CO₂ concentration is high, a physical solvent is favoured; in either case, additional processing will be required if there is much SO₂ in the flue gases (as with a coal-fired plant) to avoid excessive loss of solvent.
- Use of low temperature (cryogenic) processes is only worth considering where there is a high concentration of CO₂ in the flue gas, as could be achieved in future IGCC designs. Cryogenic processes have the advantage of producing liquid CO₂ ready for transportation to the disposal site.
- Membranes - although used commercially, for example in hydrogen separation, development is required before they could be used on a significant scale for the capture of CO₂; the extent to which their cost could be reduced is unclear.

An important aspect of CO₂ capture is the extra amount of energy required by use of such systems. This energy consumption reduces the overall efficiency of generation, typically, by 10 percentage points, which is a substantial price to pay for capturing CO₂. One attraction of membranes is that they require less energy for operation than other methods of capture. There is continual search for improvements to provide energy consumption.

For each tonne of CO₂ avoided through capture, a cost of about \$40 would be borne by the producer,

increasing the cost of electricity generation by at least 2c/kWh or 40% above current levels.

The high cost of separating CO₂ from flue gases is a major barrier to wider use of CO₂ removal technology. Substantial reductions in these costs are needed. It is uncertain whether this can be achieved through improvement to the separation process alone; a broader search is warranted for radical improvements to the whole process. This may produce worthwhile alternatives to the “end-of-pipe” approach considered to date. The IEA GHG Programme is seeking to stimulate a re-thinking of the process of generation and capture. The first stage of this work has established a common basis for assessment of new ideas. The next stage involves reviewing options which have already been identified and encouraging new ideas.

CO₂ Storage and Utilisation

After the CO₂ has been separated from the flue gases, it must either be stored or put to some use. Several conceptual schemes for storage have been evaluated, the major ones being:

- in the oceans
- in deep saline reservoirs (aquifers)
- in depleted oil and gas reservoirs
- as a solid on land

A large number of ideas have been considered for utilisation of CO₂, including:

- as a feedstock for manufacture of chemical products
- for enhancement of the production of crude oil
- in growth of plants or algae (for use as a bio-fuel)

For each scheme, a design is produced and costed, and its global capacity estimated.

CO₂ Storage

IEA GHG studies have shown that there is substantial potential capacity for CO₂ storage in natural reservoirs underground (such as deep saline reservoirs) or in the deep ocean, and could be achieved using available technology. This stage of the process would be considerably less expensive than the prior stage of capturing the CO₂ from the flue gas stream.

However, all such schemes are more or less site specific and, at present, there may be significant uncertainties about their environmental impact. Such issues are indicative of a need for further research; collaborative programmes are being developed in many of these areas.

Range of estimates for CO₂ global storage potential are:

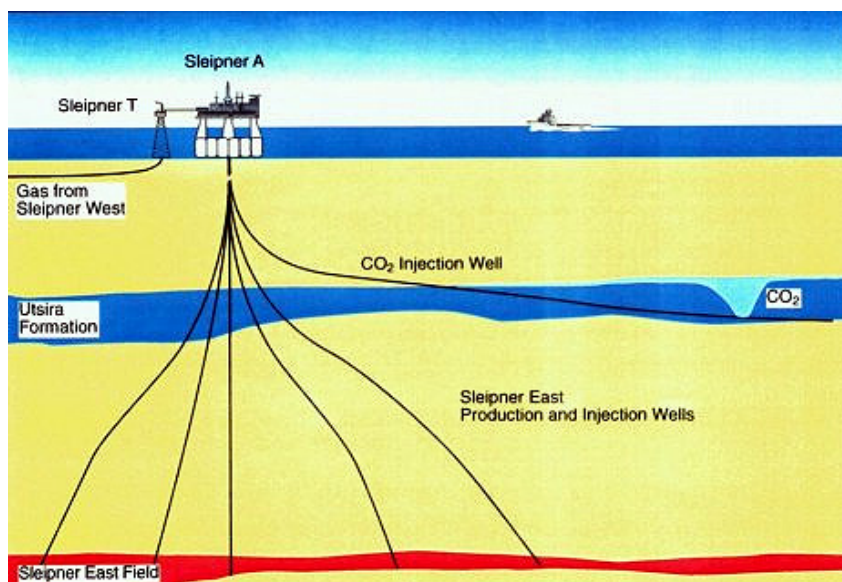
<i>Storage Option</i>	<i>Range of Values (Gt C)</i>
Ocean	1400 - 2x10 ⁷
Aquifers	87 - 2700
Depleted gas wells	140 - 310
Depleted oil wells	40 - 190

Deep-saline reservoirs

The first commercial-scale storage in a deep saline reservoir commenced operation in 1996, offshore Norway. This has been established by Statoil as part of their development of the Sleipner gas field. In this plant, 1 million tonnes/year of CO₂ are being removed from a natural gas stream using a solvent absorption process and injected into the Utsira reservoir, 800 metres below the sea-bed.



Sleipner natural gas field, site of the first commercial scale CO₂ storage in an aquifer (Statoil)



Sleipner CO₂ injection scheme

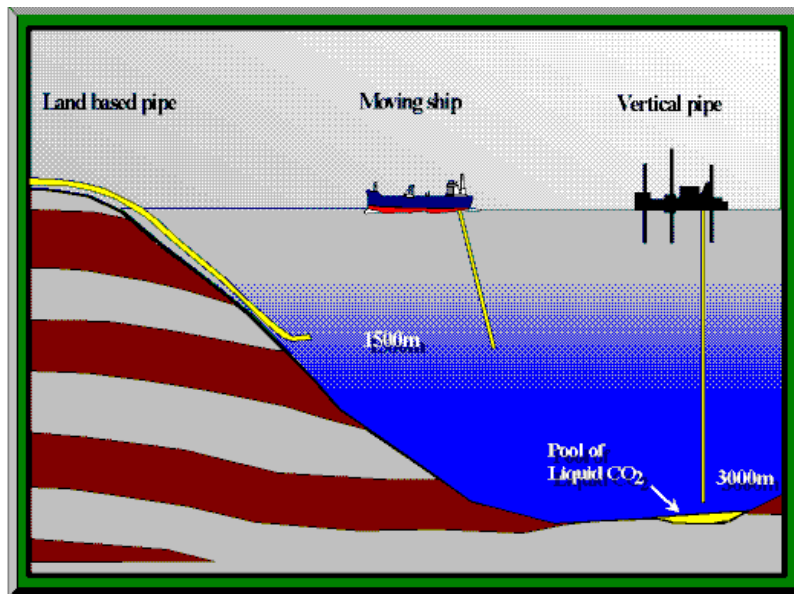
Ocean storage of CO₂

The oceans are the ultimate natural sink for CO₂ and have the greatest potential capacity in the long-term as a CO₂ store but not all countries have suitable access to deep ocean and the environmental implications are not adequately understood. The IEA GHG Programme has identified certain key questions which must be answered in order to progress this option:

- how well can the performance be predicted?
- what will be its environmental impact?
- can such schemes can be successfully engineered?
- are there major legal and jurisdictional obstacles?
- what is likely to be the public attitude to such schemes?

These questions have been addressed through a series of expert workshops, bringing together

researchers working on ocean storage of CO₂ with specialists in other, related fields. Each workshop produced a set of recommendations about work needed; in some cases these have developed into plans for collaborative research; in each case, these workshops stimulated interest amongst experts not yet working in this field, so broadening the base of expertise available.



Three of the concepts being investigated for ocean storage of CO₂ - dispersion from pipeline or ship, or production of a deep lake of CO₂

Ocean global circulation models are the only means of predicting the performance of CO₂ storage over hundreds of years. Through the workshops, an opportunity has been found to test these models against each other. The workshops also highlighted the need to study the biological impact of ocean storage of CO₂; constructive suggestions have been put forward about minimising the impact of such schemes. No substantial obstacles were identified which would impede the engineering of CO₂ storage. The need to gain public acceptance for this CO₂ sequestration concept has been highlighted. These workshops pave the way for development of robust plans for ocean storage research, which is now envisaged by a number of countries.

An expert review of the chemistry of ocean storage of CO₂ has also been prepared. All these reports are published by the IEA GHG Programme, to publicise the findings and encourage the scientific community to address the research needs identified.

Other storage options

Disused oil and gas reservoirs also have large storage capacities. They have the potential advantage of known geology to provide a seal to contain the CO₂ in the store; these represent an immediately available option.

Terrestrial disposal of solid carbon dioxide is precluded on grounds of cost. Injection of CO₂ into operating oil fields can improve oil production (EOR) and much of the CO₂ will be left in the reservoir when it is abandoned. In an analogous way, the concept has been proposed of enhancing production of coal bed methane using CO₂ injection; the CO₂ may be preferentially adsorbed by the coal, thereby enhancing release of trapped methane at the same time as sequestering CO₂. This is the subject of practical R,D&D at present.

Utilisation of CO₂

Captured CO₂ could also be used for commercial purposes, for example as a feedstock from which to make chemicals. If feasible, this would offer the twin benefits of sequestering the gas as well as replacing

other, manufactured feedstocks. CO₂ is already used for a wide range of purposes in the food and oil industries although, in most cases, the gas is not permanently stored in the products but is lost to the atmosphere at a later date. The income generated from sale of the products would help offset the cost of capturing carbon dioxide. Nevertheless, significant costs would be incurred in producing a chemical product and such processes generally require input of energy, thereby emitting more CO₂ (if the energy comes from fossil fuels). Utilisation of CO₂ to make chemicals is only effective as a mitigation option if, overall, less CO₂ is released than would have otherwise have been the case.

Such requirements are not always recognised. To address this, IEA GHG has developed an assessment procedure which provides a simple means of deciding on the suitability (or otherwise) of any chemicals proposed for fixation or off-set of CO₂ emissions. Test criteria are presented in the form of a work-sheet, which can be readily completed using information from standard reference texts. In this way candidate chemicals are quickly assessed for suitability before significant amounts of effort are put into their development. Of the chemicals tested so far, only one has achieved an overall positive rating.

Enhanced oil recovery (EOR) has a very large potential for utilising CO₂ and is employed commercially in a number of oil fields (using naturally occurring CO₂). Although there is little economic incentive to use CO₂ recovered from power stations for this purpose, various schemes are on the drawing board.

Whilst the storage time should be long, there is a danger that future oil field operations might release the stored CO₂ into the atmosphere.

Direct use of CO₂ to grow algae in order to make bio-fuels might be viable but only in certain locations; a similar conclusion has been reached about growth of crops to produce liquid fuels, currently an option of popular discussion.

Assessing the Global Impact

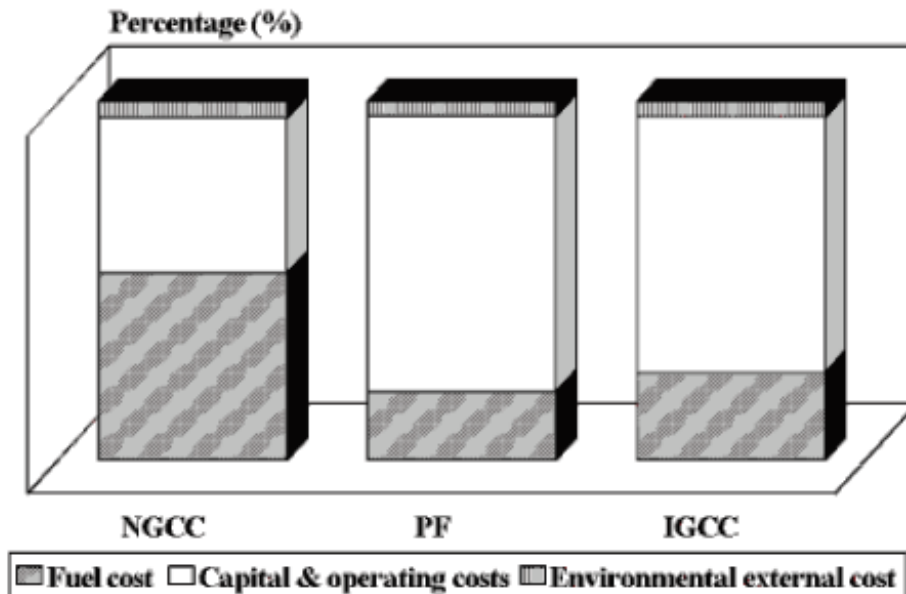
Decisions about investment of private capital in power generation are taken using well established procedures. These take no account of any impact on the environment other than through adherence to the appropriate regulations.

Recognising the need for improved information about the effects of energy investment, a major study was undertaken by IEA GHG to develop a basis for assessment of power plant including its environmental impact. This involved estimating “external costs” which are representative of the environmental impact of the whole process of extracting the fuel, operating the plant and dealing with its emissions. This is the first such study to include the full cost of avoiding greenhouse gas emissions. As a test of the method, 3 power generation and capture systems were examined, together with various CO₂ storage techniques. The plant were assumed to be built in the Netherlands; 2 of the systems used coal, the other used natural gas.

A large number of environmental impacts were examined at the local, regional and global level. Wherever possible, results from other studies were incorporated (e.g. assumptions about the future of the global economy were based on one of the scenarios developed by the Intergovernmental Panel on Climate Change) so that subsequent discussion could focus on the methods and on the results associated with climate change.

The main finding is that, as a consequence of adopting measures to capture and dispose of CO₂, the external costs arising from these power cycles are small. Most of the cost is carried by the operator of the plant. This approach illustrates, in principle, how to examine the complex issues involved in considering the impact on society of any new energy system. Much work remains to be done, both in improving the data and the techniques, before widespread use can be recommended. Work is underway to gain further experience with this approach.

A limited extension of the original study examines how the results are affected by changes in some of the key assumptions, in particular by using more than one scenario. This study is one of the first to examine



Comparison of the full-fuel cycle costs of 3 power systems incorporating capture and storage of CO₂.

the influence of different IPCC scenarios on the results. A comparison is also made of cases with and without CO₂ removal. Another new development is examination of the variation of the impact between different parts of the world. As a result, we are better placed to know how this type of approach should be used and what its limitations are. Guidance for future work was gained from an expert workshop with a wide range of participants which discussed the main features of the method and recommended priorities for future development.

A further full fuel cycle method is now being conducted - in a different location (Asia), with a different technology (LNG) - to assess the robustness of the method and broaden the database of results. The preliminary results show the value of this approach in making explicit the key issues concerning production of fuel, generation of power and mitigation of CO₂ emissions. This method can usefully illuminate discussions about the impact on society of investment in new energy systems. It can help to examine the balance between private costs and external costs.

Eventually, it could provide a rational basis for decision making about energy investments and, especially, about choice of mitigation techniques. For power plant with CO₂ capture and storage, the external costs are small so that the selection of which option to use can be decided simply on the basis of the private costs of each technology.

Enhancing Natural Sinks

Natural sinks remove CO₂ from the atmosphere (using energy from the sun, typically via photosynthesis). Trees provide a major terrestrial sink and there are many proposals to enhance this. Oceanic sinks might also be open to enhancement but there is much greater uncertainty about this at present.

Forestry sequestration of CO₂

Useful amounts of carbon could be sequestered for long periods of time in growing forests. This can be achieved by:

- prevention of deforestation
- more effective management of existing forests

- reforesting areas which were previously forested
- planting trees in areas not previously forested

The most promising management practices are reforestation in the temperate and tropical latitudes, and agroforestry and natural reforestation in the tropics (Winjum et al, 1992). In principle, all of the above could make useful contributions but, as it takes 40-50 years for a large forestry plantation to sequester a significant amount of carbon, this is not a quick-fix solution. It may also not be a permanent solution, and much depends on the use that is made of the timber. However, a number of forestry projects are now being established as carbon sinks. They may bring other benefits ranging from reduced soil erosion to rural employment, with a relatively benign environmental image.

To make a significant contribution to offsetting greenhouse gas emissions, forestry would be required on a very large scale. For example, about 2000km² would be required to absorb the CO₂ produced during the life of a 500MW coal-fired power station; 40 000km² of forest would be needed to sequester 1GtC over a period of 50-100 years. Current forestry schemes for carbon sequestration are much smaller in scale.

Early projections suggested that 50-100 GtC could be sequestered by implementing such measures over 50 years; more recent estimates, based on studies of boreal and tropical forests, indicate a global storage potential of about 1.2GtC/y (IEA GHG 1995). The FACE foundation (Forests Absorbing Carbon Dioxide Emissions) is a Dutch organisation which aims to plant 150,000ha of forest to absorb CO₂ equivalent to that emitted by a modern 600 MWe coal-fired power plant. FACE has projects in Malaysia, the Czech Republic, Ecuador, Uganda and the Netherlands.

Uncertainties exist about land availability, elasticity of price and security of CO₂ storage. The long-term fate of forests planted specifically for sequestration purposes needs further examination. A study to assess the potential for large-scale forestry has been carried out for the IEA GHG Programme by the University of Edinburgh and ECOSUR, a Mexican research institute. This provides an understanding of the costs and implications of long-term carbon sequestration, and the sensitivity of the results to increasing use of forestry in an agricultural region.

Enhancing the ocean sink

Artificial fertilisation of the oceans has also been proposed as a way of sequestering carbon; this might either be by localised fertilisation with iron of areas deficient in this key mineral, or by large-scale fertilisation with nitrogen. The IEA GHG Programme has reviewed these options and found that there is need for substantially greater basic understanding of marine processes before either of these techniques could be deployed on a large-scale with confidence.

Practical Research, Development and Demonstration (RD&D)

Gaps in current technology, identified from IEA GHG studies, may require practical research or development to progress them towards application. There will also be a need for practical demonstration of new or improved technology. The IEA GHG Programme can facilitate international collaboration to carry out practical research, development or demonstration (R,D&D). In this way, the Programme makes a useful contribution to progressing abatement technologies towards realisation.

The first such project under the IEA GHG Implementing Agreement is investigating the combustion of fossil fuel in an atmosphere of recycled-CO₂. This should provide an improved environment for capture of CO₂. This project is being carried out in Canada and involves some members of the IEA GHG Programme.

The second practical project is investigating a method of underground sequestration of CO₂. In this case, the CO₂ will be sequestered in unminable coal measures and enhance the production of coal bed methane from these seams. This work is being carried out by Alberta Research Council and collaborating organisations; an agreement for the project was established by the IEA GHG Programme. Further initiatives are now being developed for other practical projects, including monitoring and demonstration

of CO₂ storage in a deep saline reservoir.

The IEA GHG Programme is supporting participants in the European GOSAC project (an inter-comparison of ocean global circulation models) to consider sequestration of CO₂. The main aim of GOSAC is to improve understanding of the ocean carbon cycle but IEA GHG participation makes it possible also to simulate ocean CO₂ sequestration and gain an understanding of the differences between the various models.



*Experimental investigation of CO₂-recycle combustion
(courtesy of CANMET)*



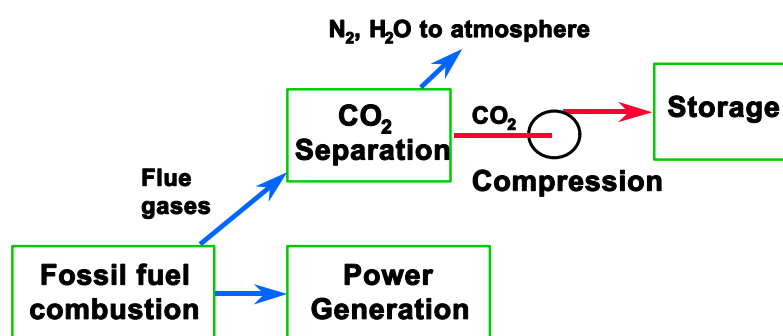
Overview of CO₂ Capture & Storage

*by Paul Freund
IEA Greenhouse Gas R&D
Programme*

Capture & Store CO₂

Power generation:

- Existing technology (post-combustion capture)



CO₂ capture at AES Warrior Run

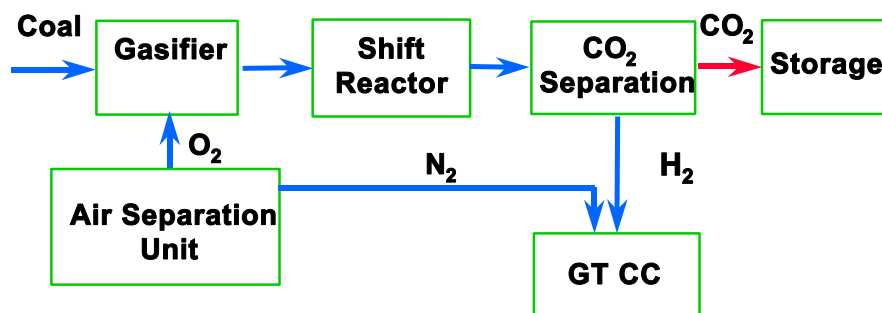


Power Generation with Capture

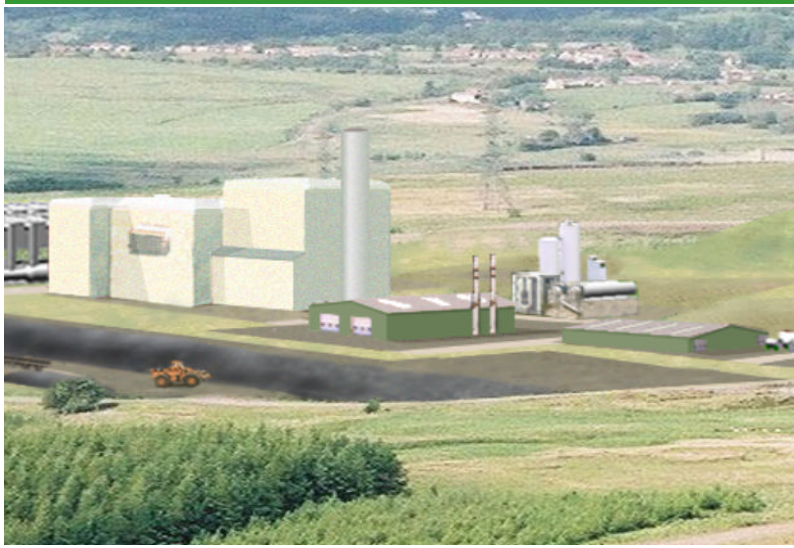


Pre-combustion decarbonisation: coal

➤ IGCC with shift



Proposed IGCC at Drym, UK



Artist's impression courtesy of Progressive Energy Ltd



O₂/CO₂-recycle combustion

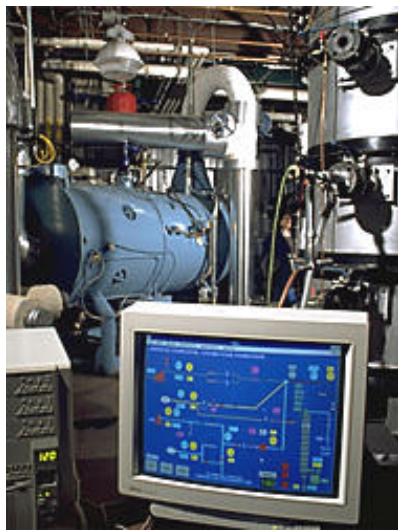
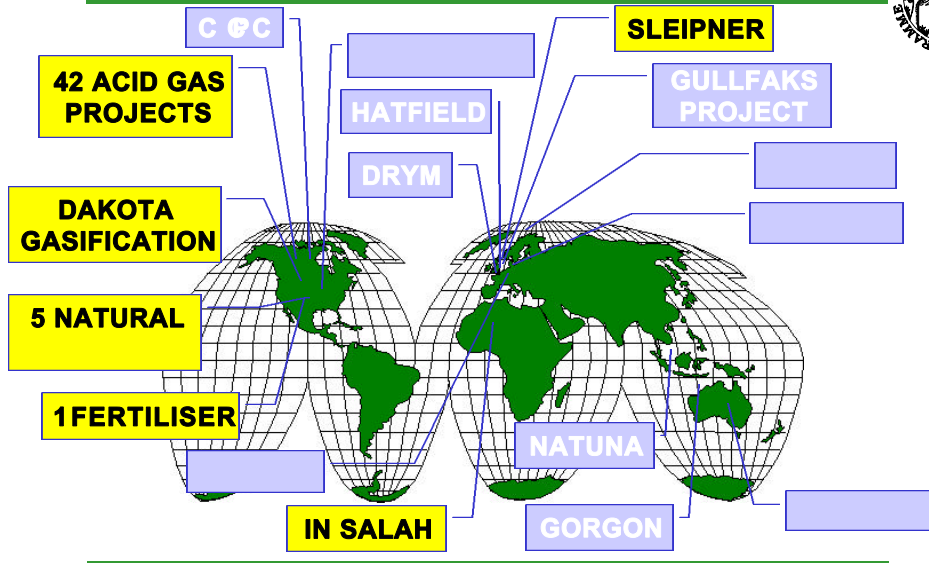


Photo: CETC



Capturing CO₂ for Injection



CO₂ transmission



CO₂ pipeline:

- 3100 km in use today
- Capacity > 110 Mt/y

Photo: Dakota Gasification

CO₂ Storage



Storage of CO₂ must be

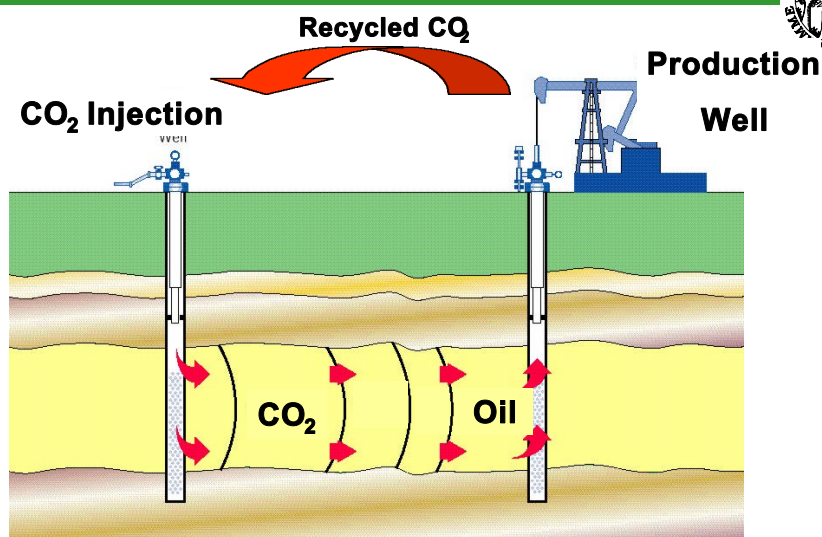
- Safe and secure
- Verifiable
- Of sufficient capacity to make a difference

Natural reservoirs have the capacity:

- Deep saline reservoirs
- Depleted oil and gas fields
- Unminable coal measures
- Deep ocean

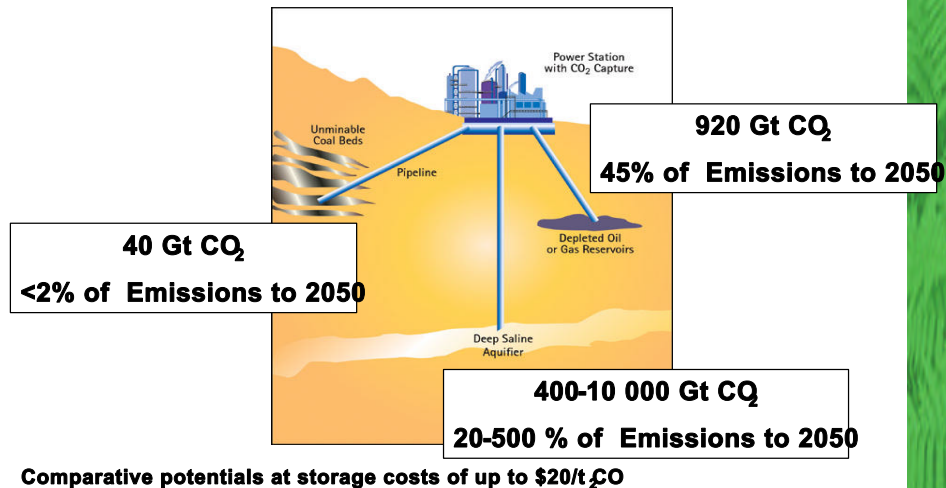
Potential for saleable products e.g. EOR

CO₂ Enhanced Oil Recovery



Geological Storage Potential

Global Storage Potential



Keeping upto-date

Website www.co2sequestration.info



- Aims of site:
 - Information on practical work on CO₂ capture and storage
 - Help promote awareness of R&D underway
 - Help facilitate cooperation between projects.
- R&D Database
 - Currently has 95 entries
 - Each entry is a current or completed project.
 - Data records from publicly available information.
 - Database updated on a six monthly basis.

Summary

Capture and storage of CO₂

- Uses existing technology
 - Can deliver deep reductions in CO₂ emissions
 - In large-scale application
 - Costs \$40-60/t CO₂-avoided (power generation)
 - Competitive with other deep reduction options
 - Enables continued use of energy infrastructure
 - CO₂ capture and storage has an important role to play in mix of mitigation options
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