# RETROFIT OF $CO_2$ CAPTURE TO NATURAL GAS COMBINED CYCLE POWER PLANTS

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# <u>RETROFIT OF $CO_2$ CAPTURE TO NATURAL GAS COMBINED CYCLE POWER PLANTS</u>

## Background to the Study

The main application of $CO_2$ capture in the long term is expected to be at new power plants. This has been the main focus of the IEA Greenhouse Gas R&D Programme's studies on $CO_2$ capture. However, there are various reasons why retrofitting $CO_2$ capture to existing power plants may be worth considering in some circumstances, for example:

- Power plants have long lives, 40 years or more in many cases. It may be cheaper to retrofit capture to an existing power plant rather than prematurely retire it and build a new power plant with capture.
- Utilities often prefer to extend the lives of existing plants rather than build new ones to minimise permitting problems and make use of existing fuel supply and electricity transmission infrastructure.
- Opportunities may arise to use captured $CO_2$, e.g. for enhanced oil recovery, in places where there is no need for new power generating capacity.

Most of the power plants currently being built in developed countries are natural gas fired combined cycle plants. Such plants could potentially be good candidates for $CO_2$ capture retrofit because they are relatively new and have high thermal efficiencies. This study assesses the feasibility and costs of retrofitting $CO_2$ capture to modern natural gas combined cycle plants. The study was carried out by Jacobs Consultancy Netherland B.V.

## Study Description

The study is based on a 785 $MW_e$ natural gas fired combined cycle plant, which includes 2 GE 9FA gas turbines. Similar gas turbines are produced by the other main turbine manufacturers. Five $CO_2$ capture retrofit options based on existing technology are assessed:

- Post combustion capture of $CO_2$
- Pre-combustion reforming of natural gas and capture of $CO_2$ at the power plant site
- Pre-combustion reforming of natural gas and capture of $CO_2$ at a remote site
- Gasification of coal and pre-combustion capture of $CO_2$ at the power plant site
- Gasification of coal and pre-combustion capture of $CO_2$ at a remote site

A preliminary assessment was carried out to select the technologies for use in the plants with $CO_2$ capture. The post combustion capture plant is based on a mono-ethanolamine (MEA) scrubbing process. The natural gas pre-combustion capture plants are based on air-blown auto-thermal reforming, followed by shift conversion and an amine scrubbing $CO_2$ separation unit. The coal gasification plants are based on the ChevronTexaco (now GE) slurry feed, oxygen-blown entrained-flow gasifier with water quench of the product gas. The gasifiers are followed by shift conversion and a Selexol physical solvent scrubbing unit for separation of $H_2S$, which is converted to sulphur, and $CO_2$. Post combustion capture was not considered for the gasification plants because it was assumed that it would be less expensive to capture $CO_2$ from the high pressure/high $CO_2$ concentration fuel gas than from the low pressure/low $CO_2$ concentration gas turbine flue gas

In the remote site cases, fuel processing and $CO_2$ capture is carried out at a plant that is 40 km from the power plant and hydrogen-rich fuel gas is transported by pipeline. Remote capture could be necessary if there is insufficient plot area or other constraints at the power plant. Post combustion capture at a remote site is not feasible because a large volume of flue gas would have to be transported between the sites.

The study was carried out using IEA GHG's standard assessment criteria. The main criteria are:

- Netherlands coastal plant location
- Australian bituminous coal
- Natural gas price \$3/GJ, LHV basis (equivalent to \$2.7/GJ HHV basis)
- Coal price \$1.5/GJ, LHV basis (equivalent to \$1.43/GJ HHV basis)
- 10% discount rate (constant money values)
- 25 year overall operating life

It was assumed that $CO_2$ capture would be retrofitted after 10 years operation of the combined cycle plant. Sensitivities to the year in which the retrofit takes place (±5 years) were assessed. It was also assumed that the whole plant, including the capture equipment would have zero value at the end of the 25 year operating period. In some cases it may be possible to replace or refurbish the power plant, to obtain a longer operating life for the capture equipment. However, gas turbines that are commercially available in future may not have the same flowrates as existing turbines, so it may be difficult to re-use capture units that are closely matched to the size of existing turbines. It may be easier to re-use capture units that are not closely linked to the power plant and which could be used to supply low-carbon content fuels to plants of any size.

Retrofitting $CO_2$ capture normally results in a reduction in net power output. In some cases a utility may need to maintain a constant net power output, so installation of additional generating capacity to maintain the net power output was assessed in sensitivity cases.

## Results and Discussion

### Thermal efficiency

Thermal efficiencies of the plants with and without $CO_2$ capture retrofit are shown in figure 1, along with the efficiency reductions due to the retrofit.

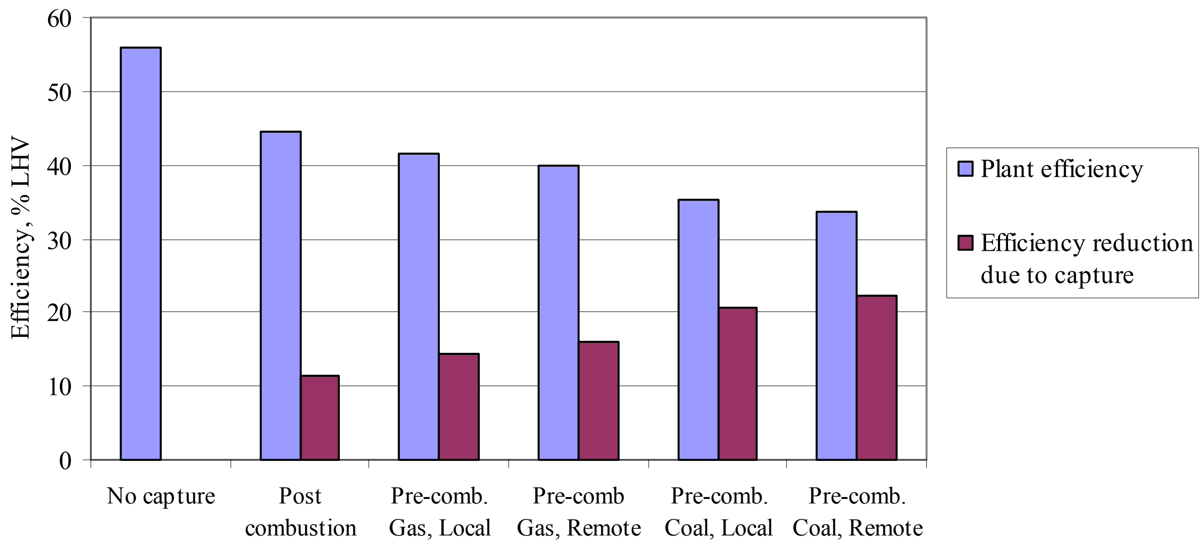


***Figure 1: Thermal efficiencies***

Post combustion capture has the lowest efficiency reduction due to capture. The highest efficiency reduction is for the coal based retrofits.

**Capital cost**

The capital costs of plants before and after retrofit are shown in figure 2. The costs are broken down into the costs of the original natural gas combined cycle (NGCC) plant and the costs of the retrofit. The cost of the original NGCC, in terms of $/kW of net power output, increases after retrofit because the overall net power output decreases, as shown later in figure 7. The capital costs of local natural gas based retrofits (post combustion and pre combustion) are broadly similar to the original costs of the NGCC power plant. The costs of remote plant and coal-based retrofits are substantially higher than the original costs of the NGCC.

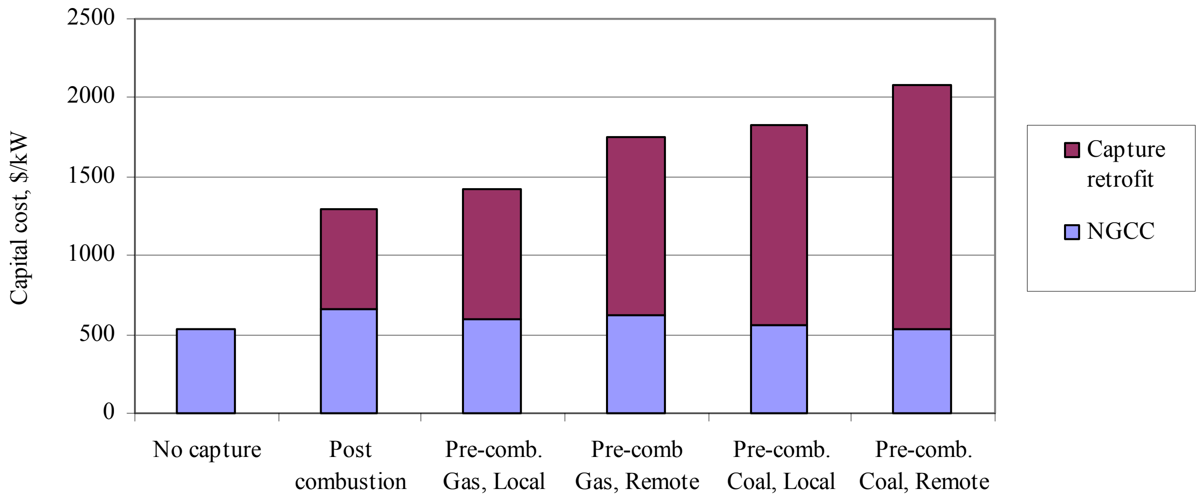


***Figure 2: Capital costs***

**Cost of electricity generation**

A power plant operator would be able to recover the cost of retrofitting $CO_2$ capture either by an increase in the electricity price or by a credit for the quantity of $CO_2$ emissions avoided, e.g. through a carbon trading scheme. The total cost of electricity generation after retrofit, assuming no carbon credits, and the increase in the cost due to the retrofit are shown in figure 3.

Figure 3 shows that the lowest cost capture retrofit option is post combustion amine scrubbing. For the natural gas and coal prices used in this study (3 and 1.5 $/GJ respectively), coal-based pre-combustion capture retrofit is slightly more expensive than natural gas pre-combustion retrofit. For pre-combustion capture, retrofit of a capture plant at a remote site is about 0.8c/kWh more expensive than retrofit at the power plant site, assuming there are no special difficulties with on-site retrofit.

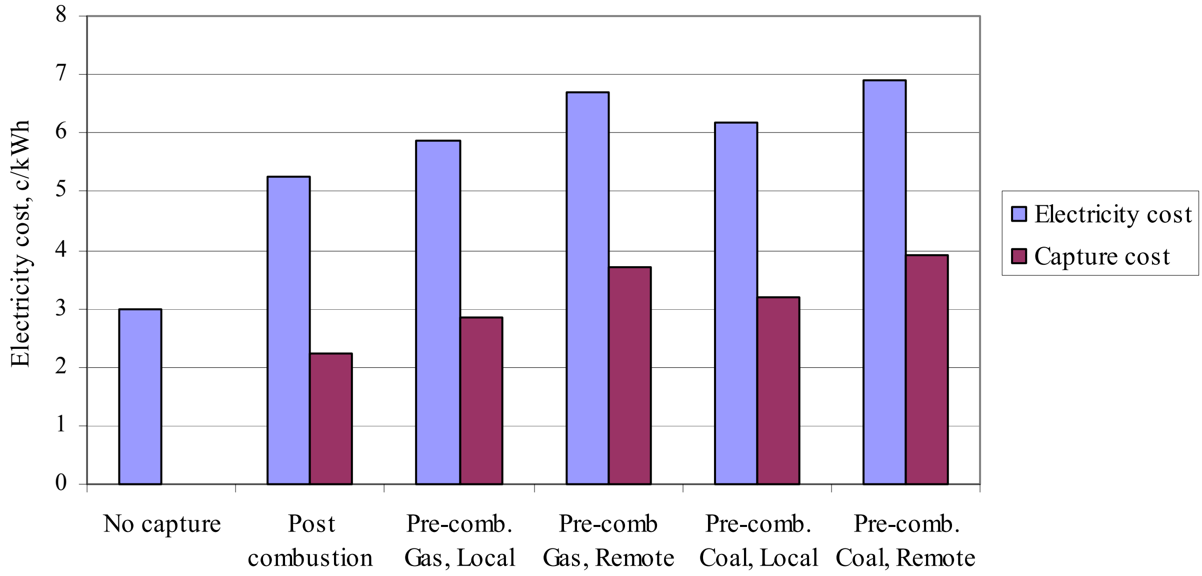


***Figure 3: Electricity generation cost after capture retrofit***

Fuel prices are different in different locations and they can fluctuate greatly over time. Sensitivities to fuel prices are shown in figure 4. A plant retrofitted with coal-based pre-combustion capture, using coal at $1.5/GJ, would generate electricity at the same cost as a plant retrofitted with natural gas pre-combustion capture, if the gas price was 3.2-3.4 $/GJ. For the coal-based retrofit to compete with post-combustion capture retrofit, the natural gas price would have to be $4.2/GJ. In some places, for example the US, natural gas prices were higher than this at the time this report was written and coal prices were lower than $1.5/GJ. Coal prices also tend to be more stable than gas prices and supplies may be more secure. Retrofit of coal gasification with $CO_2$ capture may therefore be competitive with natural gas-based capture retrofit in some places. However, as explained below, $CO_2$ emissions from coal-based plants tend to be higher, so emissions credits would be lower.

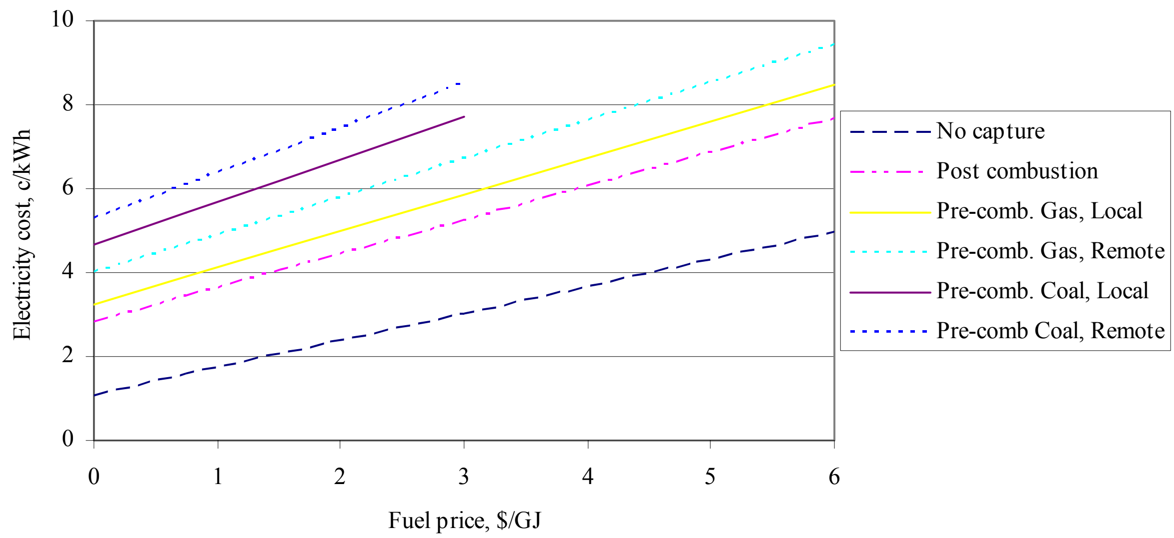


***Figure 4: Sensitivity to fuel prices***

The costs in this study exclude $CO_2$ transport and storage. As an illustration, a cost of $10/t of $CO_2$ transported and stored would correspond to about 0.4 c/kWh for a gas fired plant and 0.8 c/kWh for a coal fired plant.

**Cost of $CO_2$ emissions avoidance**

Figure 5 shows the $CO_2$ emissions from the plants with and without capture and the quantities of $CO_2$ emissions avoided. The quantities of $CO_2$ emissions avoided are calculated by comparing the emissions of the natural gas fired plant without capture and the emissions of the plants after retrofit of capture. The quantities of emissions avoided are less than the quantities captured because extra $CO_2$ is produced to provide the energy required by the capture processes. In the case of the coal gasification retrofits, the quantity of $CO_2$ captured is much greater than the emissions avoided because of the change to a more carbon-intensive fuel. All of the retrofits are based on the same percentage $CO_2$ capture. The $CO_2$ emissions from the coal-based plants are greater than from the natural gas-fuelled plants because coal is a more carbon intensive fuel and the thermal efficiencies of the coal-based plants are lower.

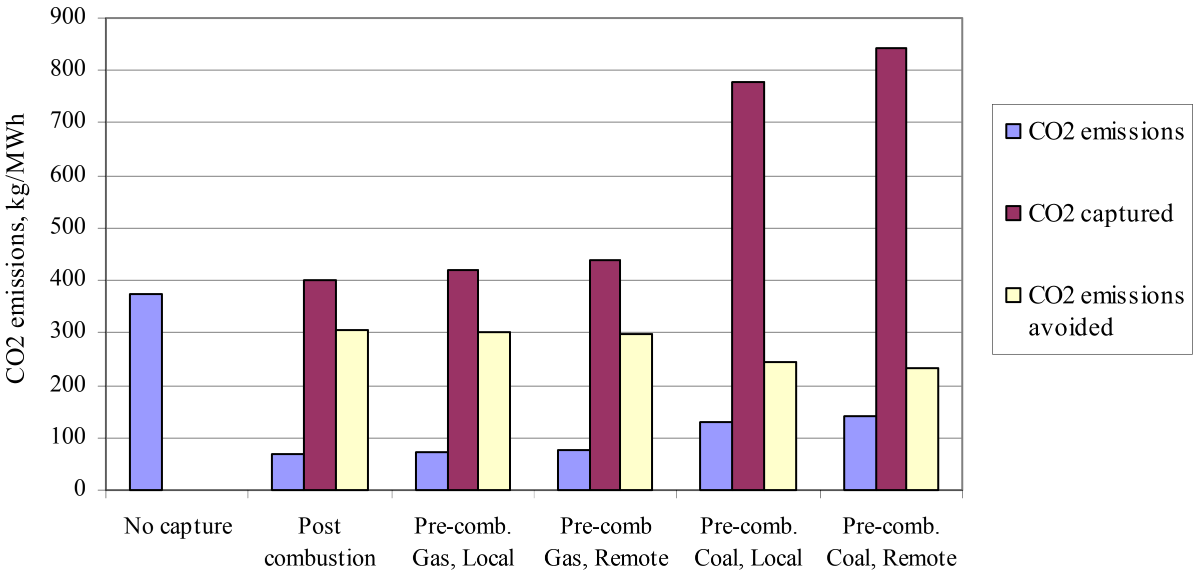


***Figure 5: $CO_2$ emissions***

The cost of $CO_2$ emissions avoidance, i.e. the $CO_2$ credit that would be required to enable a retrofitted plant to generate electricity at the same overall cost as the original plant without $CO_2$ capture, is shown in figure 6. Figure 6 also shows the sensitivity to the timing of retrofit. The base case assumption in this study is that $CO_2$ capture is retrofitted 10 years after the start of operation of the power plant and the sensitivity to retrofitting 5 or 15 years after start of operation is shown.

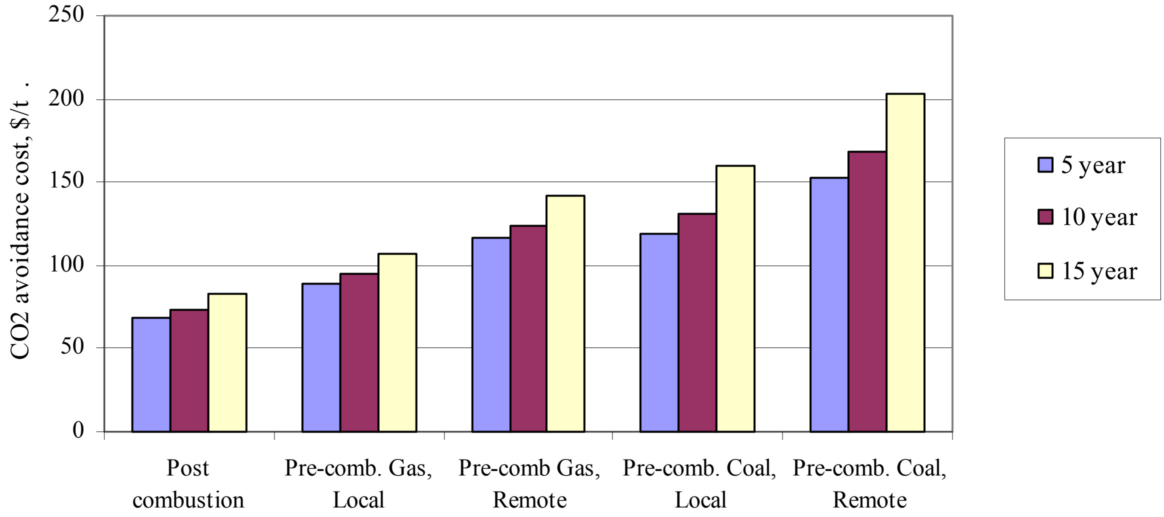


***Figure 6: Cost of avoiding $CO_2$ emissions and the sensitivity to the power plant age when retrofitted***

**Effect on net power output**

Retrofitting $CO_2$ capture reduces the net power output of an existing combined cycle plant, as shown in figure 7.

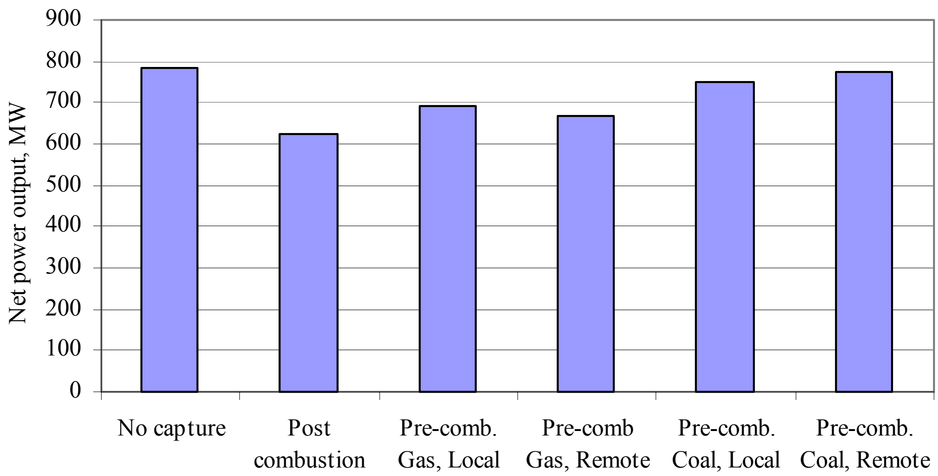


***Figure 7: Net power outputs***

The fuel feed rate to the plant with post-combustion capture is the same as to the plant without capture. The reduction in power output is therefore directly proportional to the reduction in thermal efficiency, shown in figure 1. In the plants with pre-combustion capture the fuel (natural gas or coal) feed rates depend on the fuel gas requirement of the gas turbine and the energy losses in the fuel processing stages upstream of the gas turbine. The fuel feed rates are higher than in the plant without capture and consequently the reduction in net power output is less than the reduction in thermal efficiency.

In some circumstances a power plant operator may want to maintain its net power output. This could be achieved by installing additional combined cycle generating capacity at each plant that is retrofitted but this extra capacity would be less efficient and more expensive than the original generating plant. Maintaining a constant net power output in this way would reduce the overall efficiency of power generation by between zero and 2 percentage points and increase the cost of $CO_2$ emissions avoided by between zero and 5 \$/t of $CO_2$.

**Barriers to retrofit**

In general, standard combined cycle power plants are not designed for the future possibility of major modifications. This study identifies possible barriers to retrofitting $CO_2$ capture to existing combined cycle plants and possible ways to minimise them during the original plant design phase, i.e. making the plants "capture ready".

The $CO_2$ capture retrofit plants require a considerable plot space. The approximate plot spaces are:

- Post combustion capture 250x150m
- Natural gas pre-combustion capture 175x150m
- Coal gasification pre-combustion capture 475x375m

Significant additional plot space is also required during construction. If there insufficient area available at the combined cycle plant, a pre-combustion capture plant could be installed at a remote site but, as shown by figure 2, this increases costs.

Space available within the combined cycle plant for tie-in of large diameter steam and fuel gas pipes may be a constraint in some cases. Other possible site constraints include the need to provide additional cooling and demineralised water, coal supply and storage infrastructure in coal fired cases, and accessibility for delivery of large plant items. Obtaining permits for major modifications to the power plant or construction of a remote capture plant and its fuel gas pipeline could be a barrier in some circumstances.

Gas turbine performance will differ significantly when firing a low-LHV fuel gas from pre-combustion capture plant, which will also lead to changed process conditions in the steam cycle. As no design is exactly the same, it will be necessary to determine possible problems for each installation that is retrofitted. Retrofit of $CO_2$ capture could also affect plant operating flexibility, such as the ability to operate efficiently at part load.

Many of the potential barriers to retrofit could be overcome in the design phase of a new combined cycle power plant. This would lead to minor extra costs but the cost savings at the retrofit stage could be substantial, for example if the need to build a remote capture plant is avoided.

As a sensitivity case, the study briefly assessed retrofit of a capture-ready coal gasification plant, which could be operated efficiently without capture. This option may be attractive in locations where fuel switching from natural gas to coal is economically attractive now but there is no requirement yet to capture $CO_2$.

**Comparison with IEA GHG studies on $CO_2$ capture in new power plants**

Retrofitting $CO_2$ capture to an existing power plant is inevitably more costly than including it in a new plant. Reasons for this include:

- The capture equipment has a shorter operating life in a retrofit than in a new plant.
- The efficiency is usually lower because of less energy integration between the power plant and capture unit.
- The power plant has to operate at non-optimum conditions.
- Some equipment in the power plant becomes redundant or has to be modified.
- The existing power plant has to be shut down for a period of time during the retrofit.
- Separate utility systems, such as cooling water supply, have to be installed for the capture unit, resulting in less economies of scale.

IEA GHG has recently published cost and performance data for post combustion $CO_2$ capture in new power plants, on the same basis as this study[1]. The cost of post combustion capture in a new natural gas combined cycle plant was estimated to be \$37-41/tonne of $CO_2$ emissions avoided, compared to \$73/tonne in the corresponding retrofit case in this study. This higher cost for retrofit is partly due to the reasons given above but a further reason is the different sources of cost data in the new and retrofit plant studies. This retrofit study is based on information provided to Jacobs by UOP, for a conventional MEA scrubbing process. IEA GHG's study on new plants was based on data provided by Fluor and MHI are for their improved scrubbing processes (Econamine FG+[SM] and KS-1), which have much lower steam consumptions for solvent regeneration. The efficiency penalty for post combustion capture in this study is 11.3 percentage points but the penalty is 8.2 and 6.0 percentage points in Fluor and MHI's studies. The specific capital cost penalty for $CO_2$ capture in this retrofit study is approximately twice as great as in IEA GHG's new plant study. The data provided by UOP is conservatively based on eight parallel $CO_2$ absorbers, compared to 3 and 2 in Fluor's and MHI's studies. The resulting economies of scale account for a significant proportion of the cost difference. Despite the conservative data used for post combustion capture in Jacobs' study, post combustion capture is still the lowest cost retrofit option. Use of Fluor's or MHI's processes would not have affected this conclusion.

IEA GHG has also published a study on $CO_2$ capture in new IGCC plants[2], which was carried out by Foster Wheeler. The cost and performance data for gasification plants based on Chevron Texaco gasification in that study are broadly consistent with those in Jacobs' study. The thermal efficiency and capital cost are both lower in Foster Wheeler's study but the differences are not great enough to affect the conclusions of this study.

## Expert Group Comments

The draft study report was sent to expert reviewers for comment. The main comments related to fuel prices. US reviewers pointed out that the gas price used in the study is low compared to current US prices. They also pointed out that one of the options considered in the study, conversion to coal gasification, would only be attractive if gas prices were much higher than the base case price used in the study. These and other comments from the reviewers are taken into account in the final version of the study report or in this study overview.

## Major Conclusions

Retrofitting $CO_2$ capture to natural gas combined cycle plants would increase the cost of electricity by about 2-3c/kWh, corresponding to about 70-90 \$/tonne of $CO_2$ emissions avoided.

Post combustion capture is the lowest cost capture retrofit option.

Remote fuel processing and $CO_2$ capture plants could provide low-carbon fuel gas to a combined cycle plant but the cost would be about 0.8c/kWh higher than for on-site $CO_2$ capture retrofit.

There are several potential barriers to retrofit of $CO_2$ capture to existing combined cycle power plants but most of them could be overcome if the possibility of retrofit was taken into account when the power plant was designed.

[1] Improvement in power generation with post-combustion capture of $CO_2$, IEA GHG report PH4/33, Nov. 2004.
[2] Potential for improvement in gasification combined cycle power generation with $CO_2$ capture, IEA GHG report PH4/19, May 2003

Retrofitting a coal gasification plant with $CO_2$ capture could be an attractive option in some countries where gas costs are high and coal costs are low. Capture-ready gasification plants could be built if there is currently no requirement to capture $CO_2$.

## Recommendations

No further work on retrofit of $CO_2$ capture to natural gas combined cycle plants is recommended at this time.

Work by others on retrofit of $CO_2$ capture to coal fired power plants, involving upgrading to ultra-supercritical boilers, should be monitored and compared to the results of IEA GHG's studies.

JACOBS
CONSULTANCY

International Energy Agency
Greenhouse Gas Programme

# Retrofit of CO2 Capture to Natural Gas Combined Cycle Power Plants

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# 1. MANAGEMENT SUMMARY

This report describes the results of a study conducted to evaluate several options for retrofitting an existing natural gas fired Combined Cycle Power Plant (CCPP) to a CCPP with a $CO_2$ capture plant.
This retrofit is set to take place after 10 years of operating the power plant as a standard CCPP.

The $CO_2$ capture options evaluated are:

- Post combustion $CO_2$ capture based on amine scrubbing of the CCPP's flue gases (case 1).
- Pre combustion $CO_2$ capture based natural gas as a fuel. This is done by reforming of natural gas in both a local (at the power plant site) case (case 2.1) and a remote (at 40 km distance) case (case 2.2).
- Pre combustion $CO_2$ capture based coal as a fuel. This is done by gasification of coal in both a local (at the power plant site) case (case 3.1) and a remote (at 40 km distance) case (case 3.2).

These options are visualized in following figure.

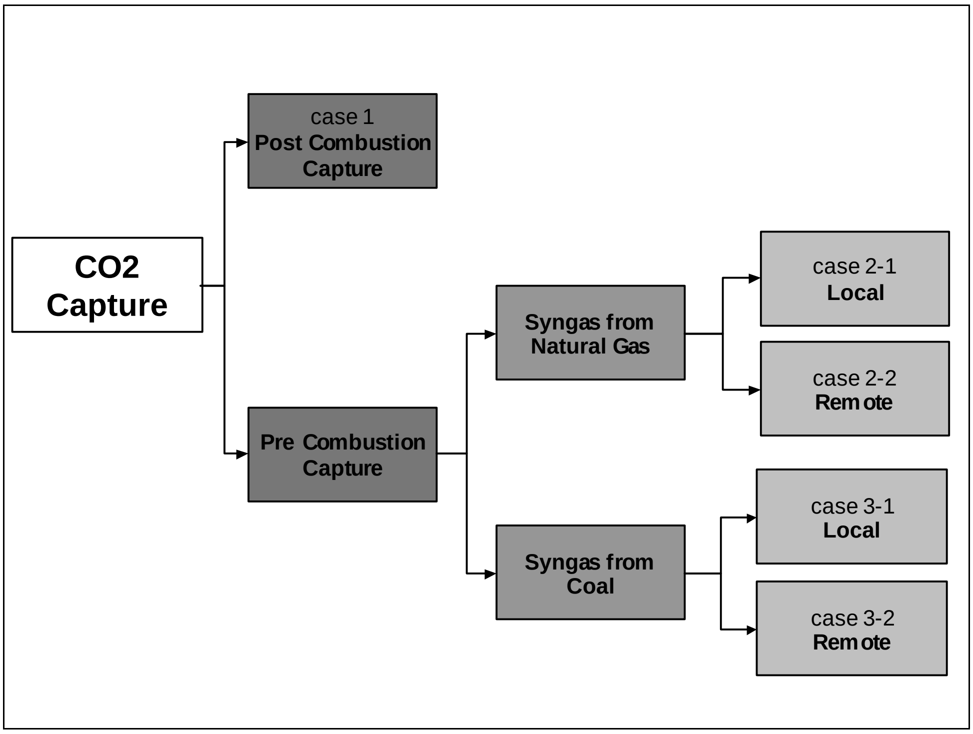



***Figure 1.1 - Cases Studied***

As part of the report a separate chapter (chapter 4) is dedicated to technology selection aspects for several process steps in a $CO_2$ capture Combined Cycle Power Plant. The technologies described and selected in this chapter are the basis for the five $CO_2$ capture cases as described in chapter 5.
For all cases considered, following characteristics have been established:

- Performance
- Avoided $CO_2$ emission
- Capital investment
- Operation & maintenance costs

Using the IEA economic model, modified for evaluation of retrofit options, following results have been obtained:

- Electricity production costs
- Cost of avoided $CO_2$

The results of these evaluations are summarized below:

| | | **Ref.** | **Case 1** | **Case 2.1** | **Case 2.2** | **Case 3.1** | **Case 3.2** |
|---|---|---|---|---|---|---|---|
| Additional[1)] capital expenditure for $CO_2$ capture plant | (mln. USD) | --- | 395 | 569 | 750 | 962 | 1194 |
| Net power production | (MWe) | 785 | 626 | 694 | 667 | 751 | 775 |
| Overall efficiency | (%) | 55.9 | 44.6 | 41.5 | 39.9 | 35.4 | 33.6 |
| Spec. total investment | (USD/MWe) | 529 | 1294 | 1419 | 1746 | 1833 | 2077 |
| Electricity costs | (USD/MWh) | 30.0 | 52.4 | 58.6 | 67.1 | 61.9 | 69.1 |
| $CO_2$ emission | (ton/MWh) | 0.373 | 0.067 | 0.072 | 0.075 | 0.130 | 0.140 |
| Avoided $CO_2$ | (ton/MWh) | --- | 0.306 | 0.301 | 0.299 | 0.243 | 0.233 |
| Avoided $CO_2$ | (% of ref.) | --- | 82.1 | 80.6 | 80.0 | 65.2 | 62.5 |
| Cost of avoided $CO_2$ | (USD/ton $CO_2$) | --- | 73.2 | 95.1 | 124.3 | 131.4 | 168.1 |

**Notes:**
[1)] On top of capital expenditure for reference plant: 415 mln. USD

From the study it becomes clear that a retrofit of $CO_2$ capture to a natural gas fired CCCP requires a significant cost of investment and results also in a significant reduction of the overall electric efficiency. The post combustion $CO_2$ capture option is strongly preferred from a performance and financial point of view compared to the natural gas reforming and the coal gasification based pre combustion $CO_2$ capture plants.

The post combustion option shows the smallest but still significant efficiency reduction in combination with the lowest capital expenditures and the best specific $CO_2$ emission.

The main disadvantage of the post combustion option is the requirement of installing the plant almost next to the existing CCCP because of the large atmospheric flue gas flow. As the plant requires also a large plot space, this could be a problem for retrofitting.

Other conclusions are:

- All options comply with the $CO_2$ capture efficiency of 85%.
- The remote pre combustion options require a higher cost of investment and have a lower efficiency due to transportation of the fuel gas.
- The overall power generation availability of the retrofitted plant is “identical” to the reference CCCP.

Taking this as a basis, sensitivity analyses have been made for:

- Fuel price : +100% and –50%
- Discount rate : 5% (instead of 10%)
- Year of retrofit : 5 years and 15 years after start of CCPP (instead of 10 years)

- Sensitivity analyses on fuel price show a different behaviour of the cost of avoided $CO_2$ for the coal-based plants compared to the natural gas fuelled plants. An increase of the fuel price results in an increase in the cost of avoided $CO_2$ for the natural gas fuelled plants and a decrease of cost for the coal fuelled plants. In case of a fuel price reduction the opposite occurs. Sensitivity analysis on discount rate show, as expected, a reduction of the costs of avoided $CO_2$ for all cases considered with a reduced discount rate.
- Sensitivity analyses on the year of retrofit show as expected that when the retrofit is executed at a later time, the cost of avoided $CO_2$ increase.
- The post combustion option remains the best option from a financial point of view for all sensitivities considered.

Additionally one chapter (chapter 8) is dedicated to issues related to future retrofitting, which can be anticipated for in the design stage of the original Combined Cycle Power Plant.

Indications are given for:
- Plot space requirements of the various retrofit options. They range from 175x150 to 475x375 m.
- Additional required cooling water capacities. These additional capacities range from 21,000 to 83,000 $m^3/h$.
- Additional required space for 12” to 36” additional fuel gas line to the gas turbine when retrofitting.
- Additional required space for 36” LP steam line from the CCPP steam turbine to the $CO_2$ capture plant in the local cases.

In this chapter some notes on availability and the effect on $CO_2$ capture of failure of some process units are also given. In all cases, provided that the CCPP is allowed to operate temporarily without capturing 85% $CO_2$, the availability is not affected by installing a capture plant.

Furthermore some capex reduction options and performance improvement potential have been identified.

**Additional Tasks**
Two additional tasks were carried out by Jacobs as a supplement to the study:

**Task 1 – Same Output Retrofit**
In all cases, the action of retrofitting the CCPP to capture 85% of the $CO_2$, results in a reduction in net generation capacity. However, some operators may be contracted to retain the original plant output.

In order to achieve this it is necessary in most cases to install supplementary combined cycle power plant either with additional flue gas scrubbing capacity or fuelled from an enlarged capture plant.

The results of these evaluations are summarised below:

| **Additional Power Requirements** | Ref. | 1 | 2-1 | 2-2 | 3-1 | 3-2 | |
|---|---|---|---|---|---|---|---|
| Total Overall Plant Net Power Output | 784.8 | 625.9 | 693.7 | 667.4 | 751.2 | 774.6 | MWe |
| Additional Power Required | - | 158.9 | 91.1 | 117.4 | 33.6 | 10.2 | MWe |
| Additional Combined Cycle Gas Turbine Type | - | GE9EA | GE6FA | GE9EA | GE6B | - | |
| | | | | | | | |
| Revised Overall Plant Net Power Output | 784.8 | 780.2 | 786.9 | 805.4 | 793.9 | 784.0 | MWe |
| Revised Overall Plant Net Electrical Efficiency | 55.9 | 43.8 | 40.6 | 37.9 | 34.2 | 33.6 | % |

The study demonstrates that the reference case output can be closely matched with $CO_2$ capture using additional gas turbines.

In all cases the overall efficiency is reduced. This is because the additional gas turbines are all less efficient than the GE 9FA used in the CCPP. This increases specific $CO_2$ emissions and the increase in capacity increases overall $CO_2$ emissions.

In all cases the total capital costs are increased, but in the specific capital cost differ marginally compared to the results of the original study.

| **Additional Capital Expenditures** | Ref. | 1 | 2-1 | 2-2 | 3-1 | 3-2 | |
|---|---|---|---|---|---|---|---|
| Additional Capital Costs[1] | - | 584 | 712 | 978 | 1045 | 1210 | Million US $ |
| Specific Total Investment | 529 | 1280 | 1432 | 1729 | 1839 | 2073 | US $/MWe |
| Costs of Avoided $CO_2$ | - | 74.3 | 98.2 | 128.9 | 136.9 | 167.5 | US $/ton |

Notes
1. On top of capital expenditure for reference plant of 415 million US $
2. Calculated with electricity at 30.0 US $/MWh

**Task 3 _ Pre-implementation Retrofit**

A major problem facing an intended new power plant investor is the choice between a plant design that cannot capture $CO_2$ and one that can only operate with $CO_2$ capture. With the former, he will face penalties under any carbon tax levy for which his only recourse is to pay. The latter choice will give him an uncompetitive plant for today that produces by-product $CO_2$ to no benefit.

An option is to design a fuel plant which is $CO_2$ capture ready based on the designs for Cases 3-1 and 3-2, renamed Cases 3-3 and 3-4 respectively. These designs could be operated to advantage without $CO_2$ capture. The fuel gas diluent of nitrogen and water vapour, both of which are energy intensive to use, could be replaced simply by leaving the $CO_2$ in the fuel gas. Here it acts as the diluent and is eventually discharged up the stacks of the CCPP and Power Block.

The results of these calculations are summarised below.

| **Plant Performance Output** | Ref. | 3-3 | 3-4 | |
|---|---|---|---|---|
| Combined Cycle Power Plant Net Electrical Output | 784.8 | 846.6 | 820.8 | MWe |
| Overall Plant Net Power Output | 784.8 | 973.6 | 932.6 | MWe |
| | | | | |
| Total Plant Fuel Consumption (LHV) | 1404.6 | 2388.7 | 2390.7 | MWth |
| Overall Plant Net Electrical Efficiency | 55.9 | 40.8 | 39.1 | % |

The economic results are shown in the table below.

| **Additional Capital Expenditure** | Ref. | 3-3 | 3-4 | |
|---|---|---|---|---|
| Additional Capital Costs[1] | - | 949 | 1102 | Million US $ |
| Specific Total Investment | 529 | 1401 | 1627 | US $/MWe |
| Costs of Electricity | 30.3 | 44.4 | 49.8 | US $/MWh |

Notes
1. On top of capital expenditure for reference plant of 415 million USD

A fuel plant can be built which is $CO_2$ capture ready and used to refuel an existing gas turbine at similar efficiencies and costs to a traditional IGCC without the ability to capture $CO_2$. The prices for natural gas and coal as used in the study means that the cost of electricity produced by such a plant is not competitive with electricity produced from natural gas in a combined cycle. However, there are some parts of the world, most notably North America where the price differential between coal (or petroleum coke) and natural gas would mean that refuelling a natural gas combined cycle with syngas are commercially attractive.

## 2. INTRODUCTION

The International Energy Agency Greenhouse Gas R&D Programme (IEA GHG) was established in 1991 to evaluate technologies that could be used to avoid emissions of greenhouse gas emissions, particularly from the use of fossil fuels. IEA GHG is an international organisation, supported by sixteen countries worldwide, the European Commission and several industrial organisations. From this perspective IEA GHG selected Jacobs Consultancy to study the feasibility and costs of retrofitting $CO_2$ capture to modern natural gas combined cycle power plants. Jacobs Consultancy is part of the internationally operating Jacobs Engineering Group, with extensive experience in retrofitting, power plant technology/projects and fuel reforming.

Fossil Fuel fired power stations are responsible for a large part of the worlds $CO_2$ emissions. Decreasing their emissions is an important step in decreasing the total $CO_2$ emission caused by human activity. Increasing their efficiency helps because less fuel is consumed for the same amount of electricity produced, but major efficiency improvements are difficult to obtain in today's modern installations. A different approach is to avoid the $CO_2$ being emitted by capturing it before it is emitted to the atmosphere.

Most of the power stations currently being built in developed countries are natural gas fired Combined Cycle Power Plants (CCPP). These plants could potentially be good candidates for $CO_2$ capture retrofit because they are relatively new and have high thermal efficiencies. This study will assess the feasibility and costs of different options for retrofitting $CO_2$ capture to modern natural gas combined cycle plants.

In this study two main concepts with a different approach are distinguished. The first concept is post-combustion $CO_2$ capture, where the flue gasses from a natural gas fired power plant are being led through a $CO_2$ scrubber, which removes the $CO_2$ from the flue gas.

The other concept is pre-combustion $CO_2$ capture. This comprises the reforming and treating of standard fuels to a fuel without carbon contents. When these synthesis fuels are combusted, no $CO_2$ is emitted to the atmosphere and therefore no flue gas cleaning is needed.

This study will describe and discuss the different techniques that are available for these concepts. The most promising techniques are compared to a standard power plant without $CO_2$ capture, to evaluate the consequences when $CO_2$ capture is applied. Hereto one reference case and several $CO_2$ capture cases are defined:

- Reference: Standard 800 MWe Combined Cycle Power Plant
- Case 1: Post Combustion $CO_2$ Capture
- Case 2: Pre Combustion $CO_2$ Capture: Reforming natural gas
- Case 3: Pre Combustion $CO_2$ Capture: Gasifying Coal

In addition to this, cases 2 and 3 are divided into two subcases: a local case and a remote case. The difference between those cases is that in the local case the power plant is supplied with syngas from the Fuel/$CO_2$ Capture Plant, which is on or near the power plant site. In the remote case, the Fuel/$CO_2$ Capture Plant is located at a 40 km distance from the power plant.

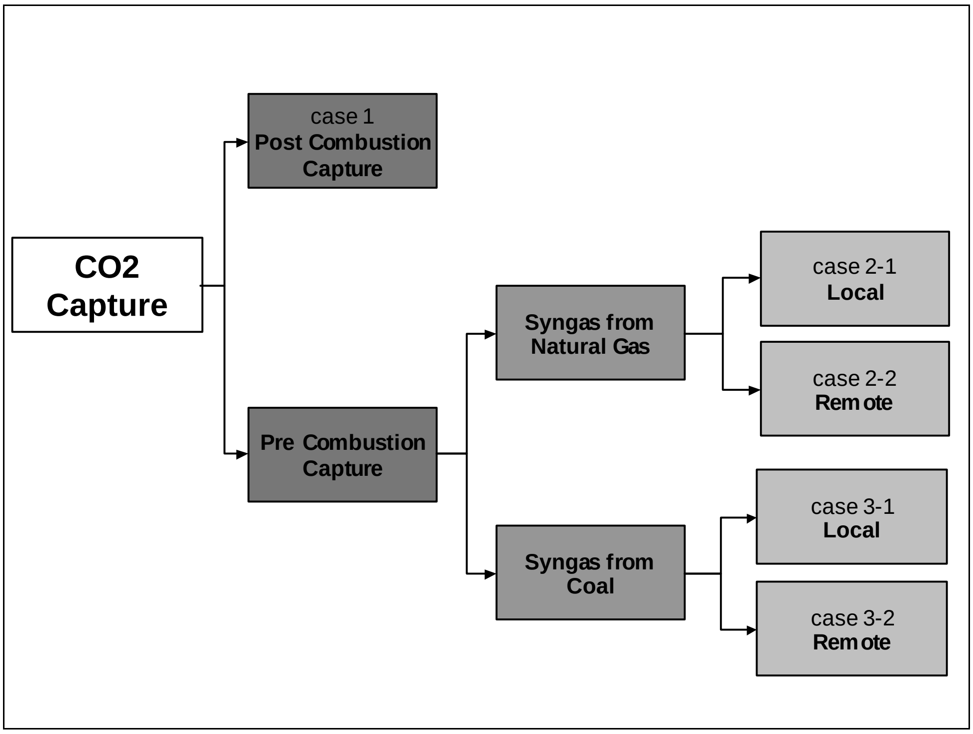



***Figure 2.1 - Cases Studied***

Retrofitting a CCPP to $CO_2$ capture requires modifications to be performed to the existing installation, as well as completely new installations to be installed. For some cases these measures will be alike, while major differences between the cases also appear. The study gives a description of these modifications and add-on installations that are needed for each individual case.

Performance calculations for the different cases are executed to compare the different options with respect to the technical performance. This includes mass and heat balance calculations with dedicated computer software, which give an exact view on the total plant performance.

Cost estimates of investment costs for retrofitting a standard power plant to a plant with $CO_2$ capture are based on vendor data as well as in-house information from Jacobs Engineering.
Together with the performance calculations, the cost estimates for retrofitting give the basis of the economic analysis, in which the different cases are compared with respect to economic feasibility.

Several barriers exist to retrofitting an existing power plant. These can be economical and/or technical barriers, which are often created because in the design phase of the

power plant, no special attention is paid to the possibility of future adjustments or expansion. When a plant is designed for future retrofit and these barriers are defined beforehand, they can be avoided which makes retrofitting less difficult, less costly and less time-consuming.
The study will define the possible barriers to retrofit an existing installation and indicate how, when designing a new power plant, a future retrofit to $CO_2$ capture can be taken into account. Furthermore the possibilities for process integration of the Capture Plant and the power plant are considered.

The report is built up as follows. Chapter 3 contains the basis of design, which incorporates all general starting points and assumptions. In Chapter 4 the technology selection for the $CO_2$ capture cases is substantiated. The process descriptions for the Fuel/$CO_2$ capture and power plant configurations can be found in Chapter 5, together with the technical performances for each case. Chapter 6 contains the capital cost and owners cost calculations, and is followed by Chapter 7 with the economic analysis. Chapter 8 describes the barriers that can arise when an existing plant is retrofitted to $CO_2$ capture and assesses the possibilities to avoid these barriers by designing for future retrofit. Overall conclusions can be found in Chapter 9.

# 3. DESIGN BASIS

The design basis gives the starting points and assumptions for the study, which are not specific for one case. If, for a specific reason it is decided to deviate from these starting points, it will be mentioned in the case description of individual cases in Chapter 5.

## 3.1 REFERENCE PLANT

The reference plant comprises two trains of GE Frame 9FA gas turbines each fitted with a triple pressure, reheat, heat recovery steam generator in combined cycle with a condensing seawater cooled steam turbine. The total plant produces approximately 800 MWe.

## 3.2 FEEDSTOCK

There are two types of feedstock; natural gas and coal. The feedstock data depicted below is provided by IEA.

### 3.2.1 Natural Gas

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian offshore reserves.

| Component | Volume % |
|---|---|
| Methane | 83.9 |
| Ethane | 9.2 |
| Propane | 3.3 |
| Butane + | 1.4 |
| $CO_2$ | 1.8 |
| Nitrogen | 0.4 |

| | | |
|---|---|---|
| Sulphur (as $H_2S$) | : | 4 mg/$Nm^3$ |
| LHV | : | 46.9 MJ/kg |
| Delivery Pressure | : | 40 barg |
| Delivery Temperature | : | 10°C |

### 3.2.2 Coal

The coal specification is based on an open-cut coal from Eastern Australia.

| Proximate Analysis | Weight % |
|---|---|
| coal (dry, ash-free) | 78.3 |
| ash | 12.2 |
| moisture | 9.5 |
| | |
| **Ultimate Analysis** | **Weight %** |
| Carbon | 82.5 |
| Hydrogen | 5.6 |
| Nitrogen | 1.8 |
| Chlorine | 0.0 |
| Sulphur | 1.1 |
| Oxygen | 9.0 |
| | |
| **Ash Composition** | **Weight %** |
| | |
| Silica as $SiO_2$ | 50.0 |
| Aluminium as $Al_2O3$ | 30.0 |
| Iron as $Fe_2O3$ | 9.7 |
| Titanium as $Ti_2O3$ | 2.0 |
| Calcium as CaO | 3.9 |
| Magnesium as MgO | 0.4 |
| Sodium as $Na_2O$ | 0.1 |
| Potassium as $K_2O$ | 0.1 |
| Phosphorus as $P_2O5$ | 1.7 |
| Sulphate as SO3 | 1.7 |
| | |
| Gross Calorific Value (kJ/kg) | 27060 |
| Net Calorific Value (kJ/kg) | 25870 |
| | |
| Ash Fusion Point (reducing Atmosphere) | 1350°C |

## 3.3 PRODUCTS PRE COMBUSTION CAPTURE PLANT

The $CO_2$ capture plant for the pre combustion capture cases delivers its products at conditions described in this paragraph.

### 3.3.1 Carbon Dioxide

The captured carbon dioxide is dried and delivered to the battery limits at 110 bar(g) and 40 °C. The $CO_2$ is sulphur free and suitable for use in Enhanced Oil Recovery (EOR).

### 3.3.2 Fuel Gas

The fuel gas for the gas turbines in the pre-combustion capture cases is delivered to the gas turbine at a minimum of 25 bar(g).

### 3.3.3 Fuel Gas Diluent

Fuel gas diluent delivered to the gas turbines in the pre combustion capture cases at which the diluent is delivered separately from the fuel gas is delivered at a pressure of at least 24 bar(g).

## 3.4 ENVIRONMENTAL CONSTRAINTS

### 3.4.1 Gaseous Emissions

The gaseous emissions are in general compliance with the large Combustion Plant Directive (2001/80/EC), current requirements for maximum permitted emission levels for power stations in the EU with a capacity in excess of 500 $MW_{th.}$

Approximately 85% of the carbon in the primary fuel gas is captured as $CO_2$ in all cases. In the natural gas fuelled cases, Case 1, Case 2-1 and Case 2-2, the primary fuel gas is natural gas. In the coal gasification cases, Case 3-1 and Case 3-2, the primary fuel gas is the raw synthesis gas from the gasifier high temperature cooling system.

### 3.4.2 Liquid Effluent

Most liquid discharge is treated to a sufficient standard so that it can be discharged into UK inland waterway.

A minimal amount of liquid effluent may be sent to a controlled landfill.

### 3.4.3 Solid Effluent

Most solid effluents are treated to a sufficient standard so that they can be sold e.g. sulphur or solid slag.

Some solid effluent is sent to specialist contractors for recovery e.g. spent catalysts and absorbents

The proportion of solid waste sent to controlled landfill is minimised.

## 3.5 ADDITIONAL CAPACITY, AVAILABILITY AND SPARES

### 3.5.1 Additional Capacity

There is no additional power generation capacity installed in the existing combined cycle power plant to replace that used to capture or compress the $CO_2$.

### 3.5.2 Availability

The overall availability of the power station on the primary fuel after retrofit is minimal 90%.

### 3.5.3 Spares Philosophy

All rotating equipment, except steam and gas turbines and generators, are spared on a "plus one" basis, i.e. one 100% pump has a 100% spare; two 50% pumps have one 50% spare. Certain other pieces of equipment such as sulphur treatment plants, solids handing units and gasification units may also be spared to maintain the overall availability after retrofit of 90%.

## 3.6 SITE INFORMATION

### 3.6.1 Location

The Power Station is located in North East Netherlands, close to the North Sea.
For the remote pre combustion $CO_2$ capture cases 2-2 and 2-3, the capture plants are located 40 km from the power station and also close to the North Sea.

### 3.6.2 Meteorological/ Site Data

For all cases including remote pre combustion $CO_2$ capture, the following conditions apply:

| | |
|---|---|
| Elevation | 2m above mean sea level |
| Barometric Pressure | 1.013 bara – Design |
| Ambient Temperature | 9 ºC |
| Relative Humidity | 60 % |

## 3.7 UTILITIES

The utilities required at the battery limit of the unit including the required conditions are described in this paragraph.

### 3.7.1 Open Circuit Sea Water Cooling

Seawater is circulated once through major coolers and condensers and discharged directly back to the sea. A secondary closed water system is used for smaller coolers and machinery.

| | | |
|---|---|---|
| Supply: | Temperature | 12 °C |
| | Pressure | 1.6 barg |
| | Design class | ANSI 150 lb Rating |
| | Material | As for return |

| | | |
|---|---|---|
| Return: | Temperature | 19 °C |
| | Pressure | 0.5 barg |
| | Design class | ANSI 150 lb Rating |
| | Material | Cement Lined Carbon Steel 300 NB and larger<br>Epoxy lined /carbon Steel 250 NB and smaller |

### 3.7.2 Fresh Water Cooling Small Coolers and Machinery

| | | |
|---|---|---|
| Supply: | Temperature | 22 °C |
| | Pressure | 3.9 barg |
| | Design class | ANSI 150 lb Rating |
| | Material | Carbon Steel |

| | | |
|---|---|---|
| Return: | Temperature | 37 °C |
| | Pressure | 3.0 barg |
| | Design class | ANSI 150 lb Rating |
| | Material | Galvanised Carbon Steel |

Note: the use of this utility is minimised.

### 3.7.3 Plant Water

| | |
|---|---|
| Pressure | 2.7 barg |
| Temperature | 30 °C |
| Design class | ANSI 150 lb Rating |
| Material | Galvanised Carbon Steel |

### 3.7.4 Electricity

| | |
|---|---|
| Voltage | 110 kV |
| Frequency | 50 Hz |

## 3.8 BATTERY LIMITS DEFINITION

### 3.8.1 Reference Case

The battery limits for the existing reference plant are given in the following table.

| Commodity | Battery Limits |
|---|---|
| Import: | |
| Natural gas | Natural gas inlet flange |
| Fresh water | Pipe flange |
| Sea water | Sea water intake |
| | |
| Export: | |
| Electricity | Primary transformer terminals |
| Waste water | Pipe flange |
| Sea water | Sea water discharge |

**ISBL Scope**

CCPP: Combined Cycle Power Plant:

- Primary transformers and switchgear
- Seawater intake and discharge structure and pumps
- Demineralised water treatment plant

**Ancillaries Excluded from Scope**

- Connections to the electricity grid system

### 3.8.2 Case 1 Post-combustion Capture

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

| Commodity | Battery Limits |
|---|---|
| Import: | |
| Flue gases | HRSG flue gas outlet flange |
| Low pressure steam | HRSG LP steam line |
| Fresh water | Pipe flange |
| Electricity | 110 kV cable (from existing plant) |
| Sea water | Sea water intake |
| | |
| Export: | |
| $CO_2$ | $CO_2$ export pipe flange |
| Waste water | Pipe flange |
| Sea water | Sea water discharge |
| Condensate | Condensate system |

**ISBL Scope**
Existing CCPP:
- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)

New Capture Plant:
- Flue gas scrubbing unit
- $CO_2$ compressor and dryer
- Utilities - including primary and secondary cooling water, demineralised and waste water treatment plant, firewater, instrument air, roads and buildings.

**Ancillaries Excluded from Scope**
- Connections to the electricity grid system

### 3.8.3 Case 2-1 - Natural Gas Pre-combustion Capture (Local)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

| Commodity | Battery Limits |
|---|---|
| Import: | |
| Natural gas | Natural gas inlet flange |
| Fresh water | Pipe flange |
| Electricity | 110 kV cable (from existing plant) |
| Sea water | Sea water intake |
| | |
| Export: | |
| Fuel gas | Import flange on CCPP |
| $CO_2$ | $CO_2$ export pipe flange |
| Waste water | Pipe flange |
| Sea water | Sea water discharge |

**ISBL Scope**
Existing CCPP:
- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)

New Capture Plant:
- Fuel gas production plant
- $CO_2$ compressor and dryer
- Utilities - including primary and secondary cooling water, demineralised and waste water treatment plant, firewater, instrument air, flare system, roads and buildings.

**Ancillaries Excluded from Scope**
- Connections to the electricity grid system

### 3.8.4 Case 2-2 - Natural Gas Pre Combustion Capture (Remote)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

| Commodity | Battery Limits |
|---|---|
| Import: | |
| Natural gas | Natural gas inlet flange |
| Fresh water | Pipe flange |
| Electricity | 110 kV cable (from grid) |
| Sea water | Sea water intake |
| | |
| Export: | |
| Fuel gas | Inlet flange at existing CCPP |
| $CO_2$ | $CO_2$ export pipe flange |
| Waste water | Pipe flange |
| Sea water | Sea water discharge |

**ISBL Scope**

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Demineralised Water Treatment Plant (extension)

**New Capture Plant**

- Fuel gas production plant
- Sea water intake and discharge structures
- Fuel gas pipeline
- $CO_2$ compressor and dryer
- Utilities - including primary and secondary cooling water, demineralised and waste water treatment plant, firewater, instrument air, flare system, roads and buildings.

**Ancillaries Excluded from Scope**

- Connections to the electricity grid system

### 3.8.5 Case 3-1 - Coal based Pre-combustion Capture (Local)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

| Commodity | Battery Limits |
|---|---|
| Import: | |
| Coal | Coal storage pile |
| Fresh water | Pipe flange |
| Electricity | 110 kV cable (from existing plant) |
| Sea water | Sea water intake |
| | |
| Export: | |
| Fuel gas | Import flange on CCPP |
| $CO_2$ | $CO_2$ export pipe flange |
| Waste water | Pipe flange |
| Sea water | Sea water discharge |

**ISBL Scope**

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)

**New Capture Plant**

- Fuel gas production plant
- Sea water intake and discharge structures
- Coal reclaimer, conveyors, grinding and slurrying plant
- Black water treatment plant
- Fuel gas pipeline
- $CO_2$ compressor and dryer
- Utilities - including primary and secondary cooling water, demineralised and wastewater treatment plant, firewater, instrument air, flare system, back-up fuel tank, roads and buildings.

**Ancillaries Excluded from Scope**

- Connections to the electricity grid system
- Coal delivery system

### 3.8.6 Case 3-2 - Coal based Pre-combustion Capture (Remote)

In addition to the battery limits for the existing reference plant given in 3.8.1, the new plant battery limits are as in shown in the table below.

| Commodity | Battery Limits |
|---|---|
| Import: | |
| Coal | Coal storage pile |
| Fresh water | Pipe flange |
| Electricity | 110 kV cable (from grid) |
| Sea water | Sea water intake |
| Back-up fuel | Inlet flange |
| | |
| Export: | |
| Fuel gas | Inlet flange at existing CCPP |
| $CO_2$ | $CO_2$ export pipe flange |
| Waste water | Pipe flange |
| Sea water | Sea water discharge |

**ISBL Scope**

Existing CCPP:

- Combined Cycle Power Plant (for modifications only)
- Primary transformers and switchgear (for modifications only)
- Demineralised Water Treatment Plant (extension)

**New Capture Plant**

- Fuel gas production plant
- Sea water intake and discharge structures
- Coal reclaimer, conveyors, grinding and slurrying plant
- Black water treatment plant
- Fuel gas pipeline
- $CO_2$ compressor and dryer
- Utilities - including primary and secondary cooling water, demineralised and wastewater treatment plant, firewater, instrument air, flare system, back-up fuel tank, roads and buildings.

**Ancillaries Excluded from Scope**

- Connections to the electricity grid system
- Coal delivery system

# 4. TECHNOLOGY SELECTION $CO_2$ CAPTURE

## 4.1 CASE 1 – POST-COMBUSTION CAPTURE

In Case 1, $CO_2$ capture is effected by installing a scrubbing unit to absorb the carbon dioxide from the gas turbine flue gases. The absorbent solution is regenerated by heating and the $CO_2$ is compressed, dried and exported from the Capture Plant.

There are two generic types of solvents for $CO_2$; chemical solvents such as amines, and physical solvents such as poly-glycols. These are usually used as a solution in water. Both of these solvent types were developed for refinery and petrochemical applications where the process streams are at elevated pressure and in reducing atmospheres. With flue gas scrubbing, the process stream is necessarily at atmospheric pressure and in an oxidising environment.

The $CO_2$ partial pressure in gas turbine exhaust is especially low because large volumes of un-combusted air are used to cool combustion flames, moderation air is used to control the TIT (Turbine Inlet Temperature), and air is also used to cool stator and rotor blades. The typical $CO_2$ content of gas turbine exhaust is 3-4% by volume, which compares starkly with a typical figure of 10-15% for fired boilers

This means that absorption is weak and large volumes of solvent are required. The low partial pressure of $CO_2$ in the flue gas also means that solution regeneration by simple pressure reduction, or flash, is not possible. Therefore regeneration has to be achieved by stripping the rich solvent with steam. The steam is usually generated by simply boiling part of the water component in the solution. The large volumes of solution and the absence of any advantage from pressure flash mean that heating (regenerator reboiler) load is very high.

The problem of an environment that is oxidising, rather than reducing, for which the solvents were developed, is rapid degradation of the solvent. The oxidation products tend to form a solid sludge, which is filtered from the solution, and the system is "topped up " with fresh solvent on a regular basis.

The low partial pressure of the $CO_2$ means that chemical solvents such as amines are preferred rather than physical solvents. These have a stronger affinity for the $CO_2$ and therefore less solvent is required. Because of the oxidising nature of the oxygen rich flue gas, simple amines such as MEA are chosen rather than the more active and expensive amines such as MDEA.

Therefore Case 1 comprises the CCPP fuelled with natural gas followed by flue gas scrubbing with an MEA solution. The solution is regenerated in a reboiled stripping column with the heat provided by low-pressure steam taken from the steam cycle of the CCPP.

## 4.2 CASE 2 – PRE-COMBUSTION CAPTURE FROM NATURAL GAS

In Case 2, capture is effected by removing the carbon before combustion, also in the form of carbon dioxide, but generated this time through a two stage chemical process of converting the natural gas to a mixture of hydrogen and carbon dioxide.

Such pre-combustion capture of $CO_2$ requires that the natural gas is converted to $CO_2$ and hydrogen in the Capture Plant before hydrogen rich fuel gas is fed to the CCPP.

The Capture Plant first converts natural gas to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon monoxide in the syngas is then converted to carbon dioxide and more hydrogen in a series of shift reactors and then a liquid solvent is used to remove the $CO_2$ to produce the hydrogen rich fuel gas. For $NO_x$ control, the fuel gas is saturated with water.

There are two basic technologies, which can be used to convert natural gas into synthesis gas, plus two basic $CO_2$ removal technologies. Each of these has a variety of implementation options and several possible methods of $NO_x$ control.

*Figure 4.1* shows a simplified decision tree for the choice of technology for the pre-combustion capture of $CO_2$ from natural gas. It should be noted that for the remote case steam injection is applied rather than water saturation.

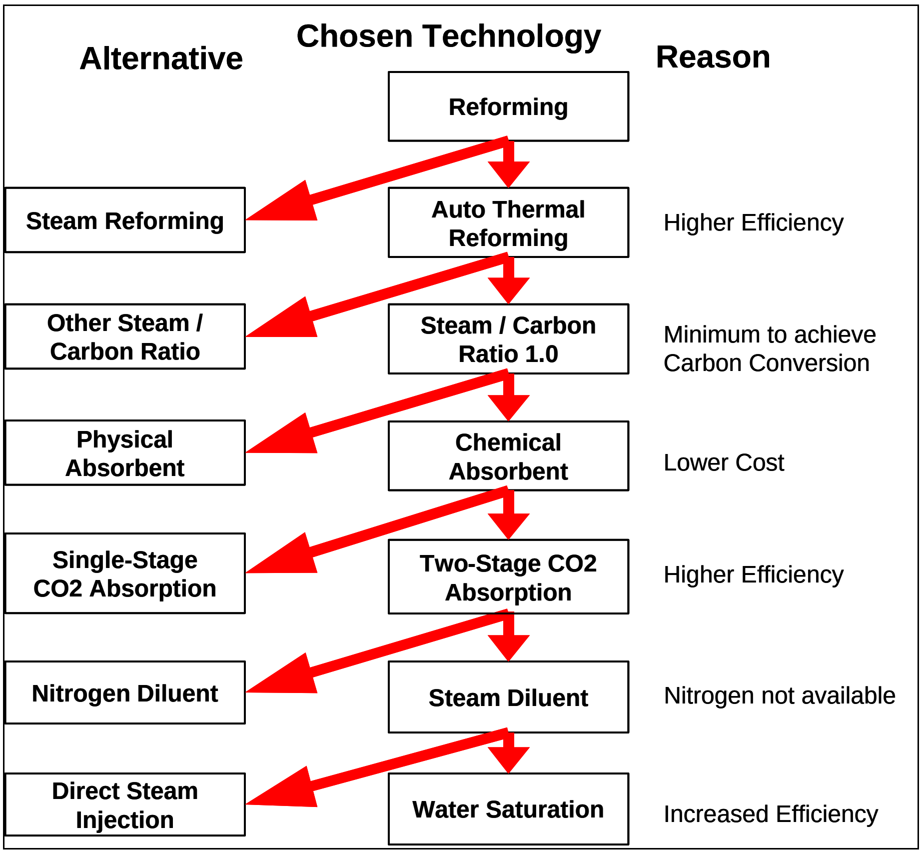



***Figure 4.1 - Technology Selection case 2***

### 4.2.1 Reforming

The chemical conversion of natural gas into mainly hydrogen and oxides of carbon is generally carried out through catalytic reaction with steam (steam reforming) or a mixture of steam and oxygen (auto-thermal reforming).

**Steam Reforming**
Steam reforming is the reaction of natural gas with steam over a catalyst at elevated temperature and pressure according to the reactions below:

Steam Reforming

$$C_xH_{2y} + xH_2O \rightarrow xCO + (x+y)H_2 \qquad (1)$$

Water Gas Shift

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad (2)$$

The reactions are endothermic and better conversion is achieved at high temperatures. The reactor is therefore configured as a series of tubes filled with catalyst inside a fired heater. The process conditions are typically 25 bar(g) and 850°C and are limited by the metallurgy of the reactor tubes. The heater is fired with either more natural gas, or in the case of a carbon capture plant, some of the carbon-free fuel gas.

The efficient conversion of the natural gas to syngas is crucial, as any unconverted carbon-containing methane left in the syngas cannot be captured as $CO_2$. The methane slip is inversely proportional to the partial pressure of the reactant steam and therefore a high steam to natural gas ratio is used. A further advantage is that conversion of the CO produced in the reformer to $CO_2$ in the shift reactor is also facilitated by the presence of large amounts of steam. A disadvantage is that the large amount of steam increases the sensible heat load in the reformer which in turn increases the fuel required by the fired heater and lowers the overall efficiency of the plant to less than 70% including auxiliary power.

**Auto Thermal Reforming**
Auto-thermal reforming is the reaction of natural gas with oxygen and steam over a catalyst at elevated temperature and pressure according to the reactions below:

Total Oxidation of Higher Hydrocarbons

$$C_xH_y + \tfrac{4x+y}{4}O_2 \rightarrow xCO_2 + \tfrac{y}{2}H_2O \qquad (1)$$

Total Oxidation of Methane

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad (2)$$

Steam Reforming of methane

$$CH_4 + H_2O \rightarrow CO + 3H_2 \qquad (3)$$

Water Gas Shift

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad (4)$$

The high temperature of the reactor, typically 1050 °C ensures that equation (3) is driven to the right, minimising the methane content of the reformed gas. This means that the amount of steam used is lower than for steam only reforming, and the exit syngas is rich in CO. The overall efficiency of the total plant including auxiliary power is just under 78%.

The capital cost of autothermal reforming is similar to steam reforming but it is significantly more efficient. Therefore autothermal reforming is chosen for the study.

The simplest way of providing oxygen for the ATR is to use air. This has the advantage of adding nitrogen to dilute the hydrogen fuel gas at the same time. The efficiency of the process is also improved by utilizing the heat from the discharge of the air compressor.

The disadvantage is that the nitrogen so introduced increases the volumetric and mass flow of the gas through the ATR, which requires more oxygen to be consumed to heat up the additional nitrogen.

The alternative is to use oxygen from an ASU. The advantages are that:

1. No nitrogen diluent is present in the ATR feed and therefore less oxygen is consumed than in the air blown case.
2. No nitrogen is present in the syngas and therefore the downstream equipment; shift, syngas cooling and acid gas removal sections are smaller and less expensive.

The disadvantage is that the ASU cost far exceeds that of the air compressor and more power is required to drive the ASU and compress the oxygen and nitrogen than is required by the air compressor alone.

Therefore as the additional capital cost of the ASU exceeds the cost savings in the downstream equipment and the parasitic power demand of the ASU is higher than that of the air compressor, an air blown ATR is chosen.

### 4.2.2 Varying Steam to Carbon Ratio in the Autothermal Reformer

A variety of steam to carbon ratios were considered. It was found that as the steam to carbon ratio was reduced, overall conversion of the natural gas decreased but the overall thermal efficiency increased. The overall capital cost of the different configurations did not vary much, but with steam to carbon rations of less than 1.25, catalyst life is reduced by 20%. The increase in efficiency more than compensates for the increased catalyst costs and therefore unit costs decrease with decreasing steam to carbon ratio. The limiting factor is then the related reduction in conversion of hydrocarbon to $CO_2$. At a steam to carbon ratio of 1.0, the overall carbon capture is just over 85%. Therefore a steam to carbon ratio of 1.0 is selected.

### 4.2.3 CO Shift system

In order to achieve the specified 85% capture of carbon, the CO in the reformed gas has to be converted to $CO_2$. Studies have shown that there is sufficient surplus steam from the reforming process to achieve this in a combination of a High Temperature (HT) and a Low Temperature (LT) catalytic shift reactor.

### 4.2.4 $CO_2$ removal Section

There are many commercial methods used for the removal of $CO_2$ from process gas streams. These include using solvents, pressure swing adsorption, temperature swing adsorption, cryogenic separation and membrane separation. For the bulk removal of $CO_2$ from high pressure process streams, pressure swing adsorption, temperature swing adsorption, cryogenic separation or membrane separation are not considered to be feasible and all large scale commercial applications use solvents.

There are two generic types of solvents for $CO_2$, chemical solvents such as amines and physical solvents such as poly-glycols. These are usually used as a solution in water. The $CO_2$ is absorbed from the syngas in an absorber column and regenerated either by simple pressure flash or by stripping with steam. The steam is usually generated by simply boiling part of the water component in the solution.

**Solvent Selection**
The advantage of chemical solvents over physical solvents is that they have a strong affinity for the $CO_2$ and therefore much less solvent is required. This means that process equipment, such as absorber and stripper columns, pumps and pipework is smaller. The strong affinity for $CO_2$ is also useful for removing $CO_2$ from process streams at low to moderate partial pressures. However, the stronger affinity for $CO_2$ also means that the regeneration energy requirement is larger.

For pre-combustion capture of $CO_2$ from natural gas, the partial pressure of $CO_2$ is less than 5 bar(a). Under these conditions, an amine-based system is selected as the reduced capital costs outweigh the slightly reduced efficiency when compared with physical solvents.

**Process Configuration**
There are several possible configurations of the amine $CO_2$ removal unit. Because of the low partial pressure of $CO_2$ in the product gas, the rich amine solution cannot be regenerated by simple pressure flash alone. Therefore some of the amine has to be regenerated using a steam stripper in order to become lean enough to absorb sufficient $CO_2$ from the syngas.

It is possible to have either a single or a two-stage $CO_2$ absorber.

In the two-stage absorber, the bulk (over 70%) of the $CO_2$ is removed in the lower section and the solution is partially regenerated by pressure flash. The partially regenerated (or semi-lean) amine solution is then returned to the top of the lower section of the absorber. The remainder of the $CO_2$ is removed in the upper section of the absorber by washing with lean amine solution which has a much lower residual $CO_2$ content because it has been regenerated with steam in a stripper column. The much lower $CO_2$ content of the lean amine means that it can absorb, on a tonne for tonne basis, much more $CO_2$ than the semi-lean solution.

Thus, if more lean solution is circulated, the duty of the semi-lean solution circuit is reduced. This reduces the pumping duty and the size of the absorber. However the size of the stripper column and the reboiler duty is correspondingly increased.

The logical extension is to have a single stage absorber and circulate only lean solution, thus removing the semi-lean solution system all together. The single stage $CO_2$ absorber is smaller in diameter and overall height than a two-stage absorber, and the pumping duty is reduced by over 60%. The disadvantage is that the diameter of the stripper column increases by over 60%, and the reboiler duty by over 170%. This additional heat requirement, of 50 $MW_{th}$, would have a significant impact on the overall plant efficiency.

The two-stage absorber option is therefore selected.

### 4.2.5 Fuel Gas Conditioning

At the exit of the $CO_2$ absorber, the fuel gas contains 42% $H_2$ plus 39% $N_2$, together with small amounts of $CO_2$, CO, $CH_4$ and Ar. This gas has a high adiabatic flame temperature and, if fed directly to a gas turbine, would generate unacceptable levels of $NO_x$. The flame temperature can be reduced and controlled either by the addition of nitrogen or water vapour.

**Selection of Diluent**

As the Auto Thermal Reformer (ATR) is blown with air, there is no Air Separation Unit (ASU); therefore a dedicated proprietary nitrogen generator would have to be used to provide nitrogen. This would consume electricity to drive the generator and compress the nitrogen, and require an expensive new unit operation. Water vapour addition is more cost effective and is therefore selected.

**Water Vapour Addition**

Water vapour can be added to the fuel gas either by direct steam addition, or by using a saturator. A saturator consists of a packed column, which directly contacts the fuel gas with hot water. Surplus water from the bottom of the column plus make-up water is pumped through a series of heat exchangers where it is reheated and returned to the top of the column. There is a small blow-down stream.

Alternatively, steam can be injected directly into the combustion chamber of the gas turbine. This steam can be taken either from the Capture Plant steam system or from the HRSG of the CCPP.

Water saturation is more capital intensive than direct steam addition because more process equipment is required, namely the saturator column, pumps and heat exchangers, however it is more efficient because it can use low grade heat from the Capture Plant which may otherwise be rejected to the cooling system. Direct steam addition is less efficient because the steam added is medium pressure, superheated steam which could otherwise be used to generate more electricity in the steam cycle.

When the Capture Plant is located close to the CCPP (Case 2-1), low-grade heat is available; therefore water saturation is selected because it is more efficient.

When the Capture Plant is remote from the CCPP (Case 2-2), there is no unused low-grade heat available, and because it is unfeasible to transmit low-grade heat over large distances, direct steam addition from the CCPP steam cycle is therefore selected.

## 4.3 CASE 3 – PRE-COMBUSTION CAPTURE FROM COAL

In Case 3, capture is again effected by removing the carbon in the form of carbon dioxide before combustion following a similar process route to the natural gas cases. However, this time, the first of the two stage chemical process of converting coal to a mixture of hydrogen and carbon dioxide consists of a gasifier rather than a reformer.

In essence, the Capture Plant converts the coal to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon monoxide in the syngas is then converted to carbon dioxide and more hydrogen in a shift reactor. The sulphur containing gases and $CO_2$ are removed with a solvent, and nitrogen and / or water added to the fuel gas for $NO_x$ control.
There are several gasification technologies a number of possible shift systems, two basic $CO_2$ removal technologies, each with implementation options, and two forms of $NO_x$ control.

*Figure 4.2* shows a simplified decision tree for the choice of technology for the pre-combustion capture of $CO_2$ from coal.

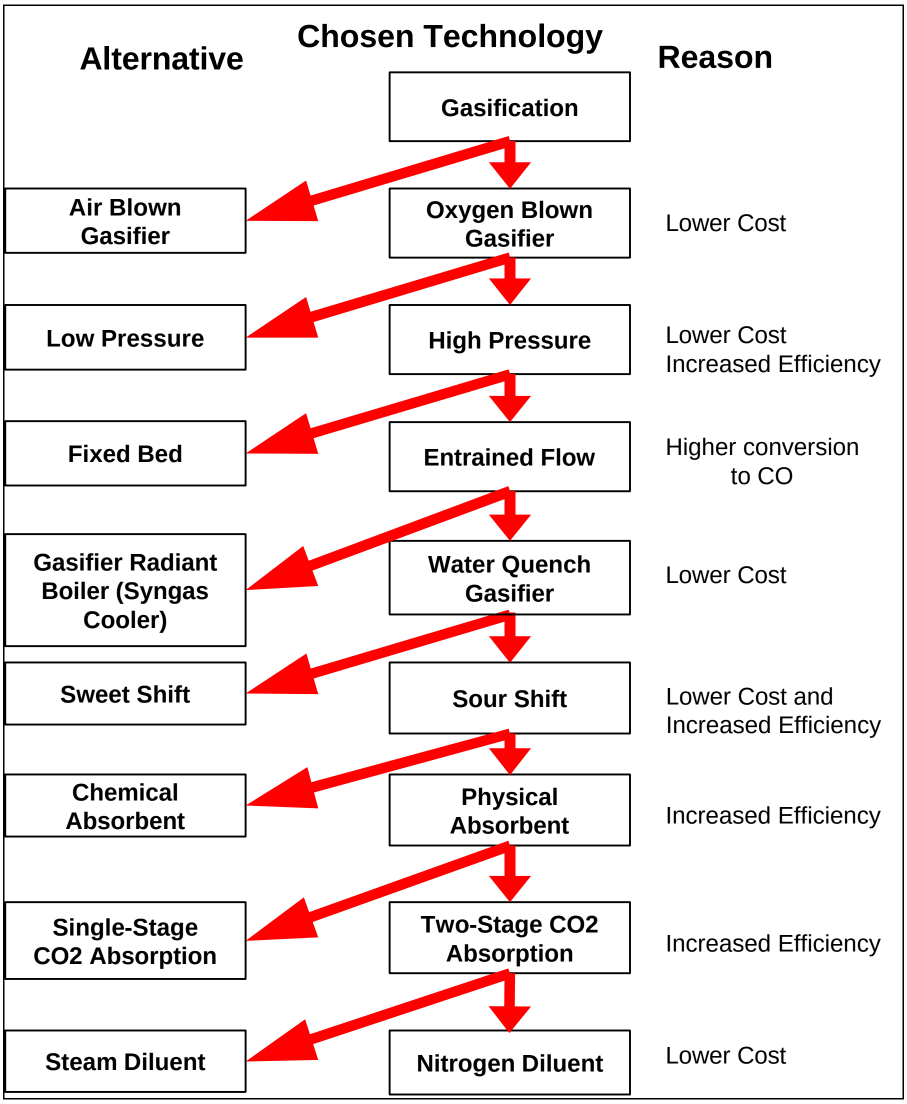



***Figure 4.2 - Technology Selection case 3***

## 4.3.1 Gasification

### Oxidant

The oxygen required for the partial oxidation or gasification of the coal can be supplied either as air or as oxygen separated from air. Using air has the double advantage of not requiring the capital investment of an ASU and directly adds nitrogen to the fuel gas, which then acts as a diluent for $NO_x$ control (see section 3.5 Fuel Gas Conditioning). The disadvantages of using air are that it is inefficient and expensive.

The capital costs of a gasification based capture plant are proportional to the volume flow through the plant. This includes the gasifier, cooling train, shift reactors and acid gas removal. Lower flowrates, mean lower capital costs.

Air contains less than 21% oxygen by volume. Therefore, to provide the quantity of oxygen required for gasification using air requires a volume flow of air nearly five times more than the corresponding flow of pure oxygen. All the nitrogen associated with the oxygen in the air will pass through the plant, raising the capital cost substantially. The use of pre-separated oxygen rather than air keeps the volume throughput at a minimum and hence the capital cost at a minimum. This reduction in cost more than outweighs the cost of an Air Separation Unit (ASU).

Using oxygen rather than air is also more efficient. If air is used, all of the nitrogen present in air has to be heated to the gasification temperature, in excess of 1400°C. The source of energy for this is oxidation of the coal. Therefore more coal has to be oxidised, and more air used, than if pure oxygen alone were used. The sensible heat in the nitrogen is recovered in the cooling systems, but that enthalpy is lost from the fuel gas and the overall process becomes less efficient.

Oxygen is therefore selected as the oxidant.

Many optimisation studies have been carried out on the effect of oxygen purity on gasification based fuel gas plants. The general conclusion is that an oxygen purity of 95 vol% is the most cost effective.

The oxygen purity selected is therefore 95 vol%.

**Operating Pressure**
The Capture Plant gasifier can operate at a range of pressures from 35 bar(g), sufficient to deliver fuel gas to a local CCPP without further compression, up to 63 bar(g), which is the highest operating pressure yet used in a commercial coal fed gasifier.

The efficiency of a gasification based Capture Plant increases with pressure for three reasons:

1. More power can be generated through an expander, letting the syngas down from gasification pressure to gas turbine feed pressure, than is used in compressing the oxidant above gas turbine feed pressure.
2. Higher operating pressures increase the temperature at which surplus steam in the syngas will condense and hence aid efficient heat recovery.
3. More $CO_2$ can be recovered by pressure flash and less reboil is required.

The capital cost of a gasification based capture plant is proportional to the volume flow through the plant. This includes the gasifier, cooling train, shift reactor and acid gas removal. Higher operating pressures mean lower capital costs despite the design requirement for thicker vessel walls.

The selected operating pressure is therefore 63 bar(g) - the highest commercially proven operating pressure to date.

**Gasifier Selection**
There are two basic gasifier types for the continuous gasification of coal to syngas:
- Entrained Flow
- Fixed Bed

Entrained Flow

Entrained flow gasifiers are fed with pulverised feedstock entrained in either water as a slurry, or in a dense phase flow under pressure with nitrogen. Main examples are ChevronTexaco and ConocoPhillips (formerly Global Energy E-Gas) – both are slurry fed; Future Energy (formerly Noell) – both slurry and dense phase flow fed; and Shell – dense phase flow fed only.

The temperature in the gasification chamber is sufficient to melt the ash. The ash becomes an inert slag or “frit” and over 95% of the carbon and hydrocarbons in the coal are converted to carbon oxides and hydrogen. Water is an important moderating reactant and in the case of the dry feed gasifiers, is added as steam.

Sulphur in the coal is converted to $H_2S$ with a little COS, and the other compounds reduced to their elements. Hydrocarbons in the exit gases are less than 1% and limited to methane.

Fixed Bed

Fixed bed gasifiers are gravity fed with lump feedstock through a lock hopper system at the top of the gasifier. The oxidant and steam moderator are injected at the bottom where most of the carbon in the coal is gasified to carbon oxides and hydrogen. As the feedstock moves down the bed, it is gradually heated by the hot gases rising from the bottom of the gasifier. The feedstock is pyrolysed, driving off the volatile hydrocarbons and sulphur compounds before they reach the bottom of the gasifier. Therefore the hydrocarbon content of the exit gases can be up to 25%, containing a large proportion of heavy hydrocarbons including tar, phenol and cresols. The sulphur is also present in complex compounds.

As fixed bed gasifiers do not convert sufficient carbon in the feedstock to carbon oxides, to be able to capture 85% of the carbon as $CO_2$, entrained flow gasifiers are selected.

**High Temperature Cooling**

Raw syngas exits an entrained flow gasifier at very high temperatures (> 1000°C) and is cooled by either raising high pressure steam in a specially designed boiler, or by being quenched in a water bath.

In the Capture Plant, the carbon monoxide in the raw syngas is converted to carbon dioxide (see section 4.2.3 CO Shift system for more details) ready for capture in a shift reactor according to the equation:

Water Gas Shift

$$CO + H_2O \rightarrow CO_2 + H_2$$

This is an equilibrium (reversible) reaction and to encourage conversion of CO, the mole fraction of the steam should be as high as possible.

The mole fraction of steam in the raw syngas from an entrained flow gasifier is low, typically 5-10%, depending on the feedstock and gasifier type. Therefore much more steam has to be added to effect the conversion of the CO to $CO_2$.

If a high pressure boiler is fitted to cool the raw syngas from the gasifier, then the generated steam can be directly injected into the syngas upstream of the shift reactor. This steam is "clean" i.e. it is produced from high quality demineralised water (demin water) and does not contain sulphur or other contaminants. Therefore it can be used in a sweet shift reactor as well as a sour shift reactor, (see section 4.3.2 Shift System for more details). The disadvantage is that direct steam injection consumes large volumes of demin water and the make-up plant has to be sized for this duty.

An alternative is to fit a direct water quench to the outlet of the gasifier. The enthalpy in the raw syngas exiting the gasifier generates steam intimately mixed with the syngas and ready for the shift reaction. The advantage of water quenched gasifiers for shifted schemes over gasifiers fitted with boilers is that the quench is a small and simple, relatively low temperature, low cost vessel. Whereas high temperature “dirty” (the hot raw syngas contains all the ash and sulphur in the feedstock) waste heat boilers are large, complex and therefore expensive.

A previous IEA GHG study[1] in which various options have been evaluated, has shown that for Integrated Gasification Combined Cycle (IGCC) plant, the lowest cost electricity is produced by designs which use water quench gasifiers. This is because the lower efficiency of the water quench design is outweighed by the lower capital cost. As the Capture Plant and the CCPP together are in effect an IGCC, it is logical that the same economic drivers apply.

Hence for this application, especially where the addition of a large quantity of steam is required for shifting of the syngas, a quench cooled gasifier is selected.

**Gasifier Technology**
An oxygen blown, entrained flow gasifier, operating at a pressure of 63 bar(g) and fitted with a quench cooler, is therefore selected. There is only one commercial gasification technology, which satisfies all of these requirements, and that is the ChevronTexaco (CVX) gasifier.

### 4.3.2 Shift System

The shift system catalytically converts CO to $CO_2$ with co-product hydrogen according to the equation:

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

[1] “Potential for Improvement in Gasification Combined Cycle Power Generation with $CO_2$ Capture” IEA GHG 2003

The shift catalyst can either be sulphur tolerant, and is then termed a “sour” shift catalyst, or it is poisoned by sulphur in which case it is known as a sweet shift catalyst.

Sweet shift catalysts can be used only with feed gases which contain very low levels of sulphur compounds, typically less than 2 ppm. The syngas from a coal gasifier contain typically 0.5% $H_2S$ which would very quickly poison a sweet shift catalyst. Therefore sweet shift catalysts have to be installed downstream of a sulphur removal unit.

Commercial sulphur removal technologies are highly active towards $H_2S$, but have difficulty in removing COS from the 100 ppm present in the raw syngas down to below 2 ppm required by the sweet shift catalyst. Therefore COS hydrolysis is required upstream of the sulphur removal unit. COS hydrolysis catalyst promotes the COS hydrolysis reaction:

$$COS + H_2O \Leftrightarrow CO_2 + H_2S$$

To use a sweet shift system, the Capture Plant therefore comprises, gasification unit and high temperature cooling, COS hydrolysis reactor, low temperature cooling, sulphur removal, reheating, steam injection or water saturation, sweet shift reactors, cooling and $CO_2$ removal.

The alternative is to use a sour shift catalyst which promotes the water gas shift reaction, COS hydrolysis reaction and the HCN hydrolysis reaction:

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

COS Hydrolysis

$$COS + H_2O \Leftrightarrow CO_2 + H_2S$$

HCN Hydrolysis

$$HCN + H_2O \Leftrightarrow CO + NH_3$$

The conversion of COS to $H_2S$ occurs simultaneously with the conversion of CO to CO2 and the level of COS in the shifted syngas is low enough to use commercial sulphur removal technologies.

Therefore, using a sour shift system, the Capture Plant comprises, gasification unit and high temperature cooling with saturation of raw syngas, sour shift reactor, low temperature cooling, sulphur and $CO_2$ removal in the same unit.

The flow schemes used in this study contain a desaturator which greatly increases the mole fraction of steam at the inlet to a sour shift reactor such that greater than 85% carbon capture can be achieved using a single bed of sour shift catalyst.

As a previous IEA study (1) has shown, the advantage of using a sour shift catalyst system is that it is simpler and lower capital cost than a sweet shift system. A sour shift system requires only one cooling train and one acid gas removal unit compared to the two cooling trains, a heating train and water saturation system, and two acid gas removal units required by a sweet shift system.

Therefore, a single bed sour shift system is selected

### 4.3.3 Acid Gas Removal

In a gasification based Capture Plant there are two acid gas species to be removed, sulphur compounds and $CO_2$. Sulphur compounds exiting an entrained flow gasifier are mainly $H_2S$ with a small amount of COS. Other sulphur compounds are negligible.

The two generic types of solvents for $CO_2$ removal are chemical solvents such as amines, and physical solvents such as poly-glycols. Both are normally used as a solution in water. The $CO_2$ is absorbed from the syngas in an absorber column and regenerated either by simple pressure flash or by stripping with steam. The steam is usually generated by simply boiling part of the water component in the solution.

Neither amines nor poly-glycols have strong affinity to COS. If COS is present in the feed to the acid gas removal unit, significant amounts of sulphur will "slip" through the unit and sulphur emission limits exceeded. COS can be hydrolysed to $H_2S$ either over a sour shift catalyst or in a dedicated COS hydrolysis reactor see section 4.2.3 CO Shift system for more details.

**Solvent Selection**

The advantages of chemical solvents over physical solvents is that they have a strong affinity for $H_2S$ and $CO_2$ and therefore much less solvent is required. This means that process equipment, such as absorber and stripper columns, pumps and pipework is smaller. However the stronger affinity also means that the regeneration energy is also larger.

The advantage of physical solvents over chemical solvents is that for $CO_2$ absorption at high pressure, the solvent can be regenerated using simple pressure flash. Also, most of the $CO_2$ is recovered at 5 bar(g), greatly reducing the $CO_2$ compressor power and costs. Thermal stripping is still required to recover the more strongly absorbed $H_2S$ from the solvent, but the regeneration energy is much less than that required by physical solvents.

For pre-combustion capture from gasified coal, the partial pressure of $CO_2$ is about 20 bar(a). Under these conditions, a poly-glycol (trade name Selexol) based system is selected as the lower energy demand, both for regeneration and $CO_2$ compression, outweighs the increased capital costs when compared with chemical solvents.

**Process Configuration**

To avoid corrosion in the $CO_2$ export pipeline, the regenerated $CO_2$ needs to be free of $H_2S$. To avoid overloading the sulphur recovery plant, the $H_2S$ in the feed to the sulphur plant needs to be kept high. i.e. the unit needs to recover the $H_2S$ and the $CO_2$ from the solvent in two separate steams.

This is carried out by absorbing the sulphur compounds first and then absorbing the $CO_2$.

Because of the low partial pressures of $H_2S$ and $CO_2$ in the fuel gas after $CO_2$ capture, the rich Selexol solution cannot be regenerated by simple pressure flash alone. Therefore some of the Selexol has to be regenerated using a steam stripper in order to become lean enough to absorb sufficient $H_2S$ and $CO_2$ from the syngas.

The acid gas removal system developed by UOP consists of separate $H_2S$ and $CO_2$ absorber columns, a third column to concentrate the $H_2S$ in the rich liquor and a steam stripper column to regenerate the Selexol.

### 4.3.4 Sulphur recovery

There are a variety of sulphur recovery technologies commercially available.

Because oxygen is available at low cost from the ASU, an oxygen blown Claus unit is selected for sulphur recovery. The tail gas from the Claus unit is compressed and returned to the inlet of the $H_2S$ absorber column and the water effluent is returned to the de-saturator.

There are no normal sulphur emissions to atmosphere other than through the gas turbine exhaust.

### 4.3.5 Fuel Gas Conditioning

At the exit of the $CO_2$ absorber, the fuel gas contains 75% $H_2$ plus 16% $N_2$, together with small amounts of $CO_2$, CO, $CH_4$ and Ar. This gas has a high adiabatic flame temperature and, if fed directly to a gas turbine, would generate unacceptable levels of $NO_x$. The flame temperature can be reduced and controlled either by the addition of nitrogen or water vapour.

**Selection of Diluent**

There is a large flow of waste nitrogen available from the ASU, which is normally vented to atmosphere. This can be compressed and added to the fuel gas as a convenient inert diluent for both pre-capture coal cases.

Water vapour can be added to the fuel gas either by direct steam addition, or by using a saturator. A saturator consists of a packed column, which directly contacts the fuel gas with hot water. Surplus water from the bottom of the column plus make-up water is pumped through a series of heat exchangers where it is reheated and then returned to the top of the column. There is a small blow-down stream.

Alternatively, steam can be injected directly into the combustion chamber of the gas turbine. The steam is either taken from the Capture Plant steam system or from the HRSG of the CCPP.

Studies carried out by Jacobs have shown that for IGCC plants, where the low grade heat can be used efficiently, the cost of electricity production using water injection or saturation (including water purchase and purification) is higher than for schemes using nitrogen dilution. The flowschemes used in this report all include a desaturator which upgrades all of the low-grade heat so that it can be used to generate low pressure steam.

Therefore for Case 3-1, nitrogen is selected as the diluent when the capture plant is local to the CCPP.

In Case 3-1 where the Capture Plant is located local to the CCPP, the nitrogen can be injected directly into the combustion cans of the gas turbine. As the combustor cans are at a lower pressure than the fuel delivery system, the diluent nitrogen can be delivered at a lower pressure than the fuel gas thus saving on parasitic compressor power.

In Case 3-2, where the Capture Plant is remote from the CCPP, the diluent nitrogen is compressed to the full fuel gas pressure, which can be up to 60 bar(g), for pipelining purposes.

# 5. PROCESS DESCRIPTIONS AND PERFORMANCES

This chapter contains the process descriptions for the considered cases. The configurations for the different capture plants are discussed, together with the modifications that are needed to the CCPP. The first paragraph describes the reference case, which contains a standard CCPP fired on natural gas. The power plant configurations for the other cases are all based on this reference case but modifications are required. These modifications are assessed as well.
The technical performances of the different cases are described and compared on a basis of electrical efficiency and $CO_2$ emission.
Reference is made to appendix 1 for CCPP simplified process scheme and mass balance. Reference is made to appendix 2 for simplified process schemes and mass balances of Fuel/$CO_2$ capture plants. Reference is made to appendix 3 for plot layouts of all plants. Reference is made to appendix 4 for equipment lists of Fuel/$CO_2$ capture plants. Reference is made to appendix 5 for overview of power consumption/production and utility usage in all designs for Fuel/$CO_2$ capture plants.

## 5.1 REFERENCE CASE: STANDARD COMBINED CYCLE POWER PLANT

This paragraph describes the process design and performance of the reference case, which consists of a standard combined cycle power plant, including the most significant design parameters for the major equipment and systems. This case represents the reference plant without $CO_2$ capture, to which the other (retrofitted) cases are compared.

### 5.1.1 CCPP Description

The study is based on an 800 MWe power plant, consisting of two identical trains of natural gas fired, standard combined cycle units. Each of the two combined cycle trains comprises:

- One gas turbine
- One triple pressure, non fired, natural circulation Heat Recovery Steam Generator (HRSG) with reheat section
- One steam turbine with HP, IP and LP-condensing sections

The gas turbine and steam turbine for each unit are connected to a common hydrogen cooled generator. (i.e. single shaft configuration)

The overall plant design, including the selected components, has been based on state of the art proven technology.

A GE Frame 9FA gas turbine (approximately 260 $MW_e$), with a dry low $NO_x$ combustion system has been selected as a typical representative proven design gas turbine in the power range considered.

| | |
|---|---|
| Type | GE PG9351(FA) |
| ISO Base Rating | 255.6 MWe |
| Heat rate | 9759 kJ/kWh |
| Pressure ratio | 15.4 |
| Mass flow | 623.7 kg/s |
| Exhaust Temperature | 609 °C |

***Table 5.1 - GE Frame 9FA Gas Turbine Performance Data***

This gas turbine can be considered as the current proven state of the art within its power range. Alternative gas turbines within this power range are (ISO base rating between brackets):

- Alstom GT26 (263.0 MWe)
- Siemens V94.3A (265.9 MWe)
- Mitsubishi M701F (270.3 MWe)

It shall be noted that the required modifications to these gas turbines when fired on low LHV fuel gas will differ for each type of gas turbine. With other words, the modifications as described in this report for the General Electric 9FA gas turbine should not be considered to be representative for gas turbines from other manufacturers.

For evaluation purposes the following starting points are used:

- Fuel: natural gas (Reference is made to paragraph 3.2.1)
- Ambient conditions as described in paragraph 3.6.2
- Gas turbine base load operation
- No degradation
- No fouling
- Other starting points:

| | |
|---|---|
| Inlet pressure drop | 10 mbar |
| Exhaust pressure drop | 30 mbar |

***Table 5.2 - Reference Case Starting Points***

The HRSG of the standard power plant is a non-fired triple pressure natural circulation boiler with single reheat. As the installation is considered to be a base load operating power plant the design is optimized with respect to the overall efficiency of the system. The higher overall efficiency will consequently result in a reduction of the fuel gas consumption and $CO_2$ emission compared to a non-optimised installation.

In the simplified process diagram of the standard design (see appendix 1) only major components are presented. Additional facilities, which are required for operation of the plant over the complete operating range such as de-superheating equipment, closed cooling water system and instrument air, etcetera are not shown. The HRSG supplies steam at the following pressures and temperatures:

| | Pressure | Temperature | |
|---|---|---|---|
| HP: High pressure | 120 bara | 560 | °C |
| IP: Intermediate pressure | 27 bara | 560 | °C |
| LP: Low pressure | 4.6 bara | 300 | °C |

***Table 5.2 - HRSG Pressure/Temperature Levels***

In order to achieve the given steam conditions the HRSG process design is according to *Table 5.3*.

| | | | |
|---|---|---|---|
| High pressure superheater | Steam temperature | 560 | °C |
| Medium pressure superheater/ reheater | Steam temperature | 560 | °C |
| Medium pressure superheater | Steam temperature | 300 | °C |
| Low pressure superheater | Steam temperature | 300 | °C |
| High pressure economizer | Degrees of subcooling | 3 | °C |
| Medium pressure economizer | Degrees of subcooling | 3 | °C |
| Low pressure economizer | Degrees of subcooling | 3 | °C |
| Water preheater | Exit temperature | 90 | °C |
| Evaporator (low, medium and high pressure) | Pinch delta temperature | 8 | °C |

***Table 5.3 - HRSG process design***

The condenser pressure is 0.04 bar. This is the saturation pressure at 29°C. This temperature is based on the seawater temperature of 12°C, a maximum allowed temperature rise of 7°C and an approach temperature of 10°C.

The design of the condensate heating/deaerator system has been based on a maximum deaerating efficiency in combination with a maximum thermal efficiency. Therefore the deaerator system will operate at a pressure of 1.2 bar; 105°C with a condensate feed water temperature of 90°C (The feed water temperature shall be approximately 15 °C below the deaerator temperature to ensure a high deaerator efficiency). LP steam will be used for deaeration and heating of the condensate.

The condensate from the condenser will be heated from 29°C to 90°C by means of a closed water loop, which is using the flue gas heat from the stack to preheat the condensate. Direct heating the condensate with flue gas is not preferred because the condensate entry temperature is below the dew point of the flue gas.

List of remaining starting points:

- For calculation of the auxiliary power consumption all the pumps used have an overall efficiency of 75%.
- The generator efficiency is 98.3%
- Blow down and deaerator vent is set at 0%
- Minor steam losses, such as the ejector steam and gland steam are neglected.

The steam turbine is split up in the following sections:

- A HP section, which is supplied with steam from the HP superheater
- A MP section, which is supplied with a mixture of steam from the MP superheater and steam from the HP turbine which is reheated in the reheat section
- A LP section, which is supplied with a mixture of steam from the LP superheater and steam from the MP turbine section

The steam turbine has the following characteristics:

| Section | isentropic efficiency | Inlet pressure | Inlet temperature | Outlet pressure | Outlet temperature |
|---|---|---|---|---|---|
| High pressure | 87.0% | 120 bara | 560 °C | 27.4 bara | 346 °C |
| Intermediate pressure | 88.5% | 27 bara | 560 °C | 4.6 bara | 320 °C |
| Low pressure | 90.0% | 4.6 bara | 318 °C | 0.04 bara | 29 °C |

***Table 5.4 - Steam Turbine Data***

An additional loss of 1% of the steam turbine shaft power output is used to take account for the shaft and other losses.

**CCPP Performance**

The resulting energy balance for the standard power plant firing natural gas is shown in *Table 5.5*:

| Power Plant Energy Balance | | | | | |
|---|---|---|---|---|---|
| Gas Turbine Energy Input | | 1404.6 | MWth | | |
| | Fuel Consumption LHV | | | 1404.9 | MWth |
| | Fuel Sensible Heat Input (Tref. 15 ºC) | | | -0.3 | MWth |
| | Total Gas Turbine Energy Input | | | 1404.6 | MWth |
| Gas Turbines | | 525.9 | MW | | |
| | GT Gross power | | | 554.4 | MW |
| | GT losses | | | -28.6 | MW |
| | Net GT output | | | 525.9 | MW |
| Steam Turbines | | 282.8 | MW | | |
| | ST Shaft power | | | 285.7 | MW |
| | ST losses | | | -2.9 | MW |
| | Net ST output | | | 282.8 | MW |
| Generator losses | | -14.0 | MW | | |
| Balance of Plant losses | | -9.8 | MWe | | |
| | Boiler feed water pumps | | | -2.8 | MWe |
| | Cooling water pumps | | | -6.0 | MWe |
| | Condensate pumps | | | -0.2 | MWe |
| | Remaining losses (0.1%) | | | -0.8 | MWe |
| | BOP losses | | | -9.8 | MWe |
| Total Plant net power | | 784.8 | MWe | | |
| Net electrical efficiency | | 55.9 | % | | |

***Table 5.5 - Reference Case Power Plant Energy Balance***

* Remaining losses are assumed to be 0.1% of the plant gross power output. These losses comprise small power consumers like the closed cooling water system pumps, instrument air compressor, HVAC, etc.

## 5.2 CASE 1: POST COMBUSTION CO2 CAPTURE

The first case comprises post combustion $CO_2$ capture, which is effected by using direct scrubbing of the flue gas with a proprietary amine solution. This is a so-called “end of pipe” method, as the capture plant is located downstream of the power plant and $CO_2$ is removed from the flue gas of the CCPP, see *Figure 5.1*.

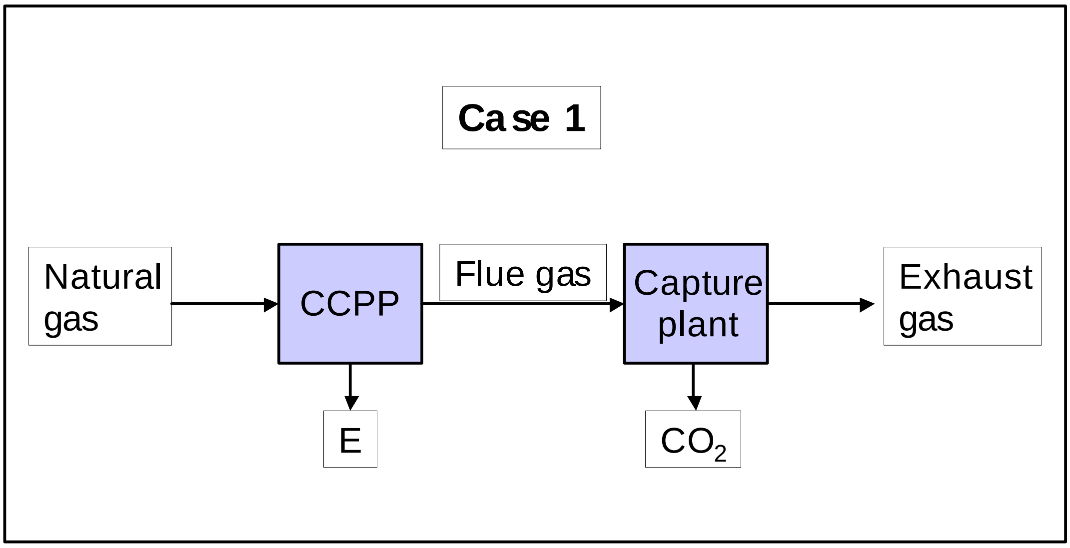



***Figure 5.1 - Case 1 Scheme***

### 5.2.1 CCPP Description

This case does not require significant modifications to the equipment of the reference power plant. The $CO_2$ capture installation will be a strictly add-on plant, only to consume energy from the power plant required for the flue gas scrubbing.
All assumptions, starting points and equipment data concerning the power plant are equal to the reference case.

Main process modifications to the reference CCPP are:

- Tie-in to LP steam system to supply LP steam from the power plant to the reboiler section(s)
- Tie-in to the condensate system(s) to receive the cooled condensate from the reboiler section(s)
- Tie-in to the stack of the HRSG’s in order to discharge the fluegas to the $CO_2$ capture plant.

For overall availability reasons it may be preferred to install switch over dampers which allow for base load operation with and without $CO_2$ capture.

Each CCPP unit is equipped with a scrubbing unit, which removes the $CO_2$ from the flue gasses. This scrubbing unit is located downstream of the Heat Recovery Steam Generator, before the flue gasses leave the stack. Paragraph 5.2.3 describes the complete $CO_2$ capture installation in detail.
The capture installation needs a significant amount of heat for its internal process. This heat is supplied in the form of superheated low pressure steam from the CCPP

steam cycle, which is extracted upstream of the condensing LP steam turbine section. A direct consequence is that the condensing LP steam turbine section will be operated at low load, with about 10% of the design steam flow through the section.
The capture unit returns 100% of the extracted steam as sub-cooled condensate, which is cooled to 30 ºC in seawater cooled heat exchangers and mixed with the condensate flow from the CCPP main condenser.
The condensate flow from the condensing steam turbine section to the condenser decreases because of this extracted steam. The main condenser duty is therefore significantly lower in comparison to the design case, and the cooling water flow is decreased to 60% of the flow in the reference case. It is required to discharge the condensate heat to the surface water, as there are no low-grade heat consumers available.

The scrubber unit will introduce an additional pressure drop at the flue gas side. If no action is taken this would result in exceeding allowable pressure limits for the HRSG and gas turbine ducting. To anticipate this an induced draft flue gas fan is introduced to overcome the extra exit pressure loss. This will introduce an additional auxiliary power consumer in the capture unit. It should be noted that installation of the induced draft fan prevents loss of performance of the gas turbine due to increased backpressure of the HRSG.

### 5.2.2 CCPP Performance

*Table 5.6* shows the energy balance for the CCPP in case 1. The energy input and gas turbine output are unchanged compared to the reference case. This is expected, as the process conditions for the gas turbine have not changed.
However, the steam turbine power output decreased considerably, which is due to the LP steam extraction. The condensing steam turbine section is almost bypassed, and this causes the output to fall from 283 MWe in the reference case to 157 MWe.

As a result, the CCPP electrical efficiency decreased to 47.3%.

| **Power Plant Energy Balance** | | | | | |
|---|---|---|---|---|---|
| Gas Turbine Energy Input | | 1404.6 | MWth | | |
| | Fuel Consumption LHV | | | 1404.9 | MWth |
| | Fuel Sensible Heat Input (Tref. 15 ºC) | | | -0.3 | MWth |
| | Total Gas Turbine Energy Input | | | 1404.6 | MWth |
| Gas Turbine | | 525.9 | MW | | |
| | GT Gross power | | | 554.4 | MW |
| | GT losses | | | -28.6 | MW |
| | Net GT output | | | 525.9 | MW |
| Steam Turbine | | 157.1 | MW | | |
| | ST Shaft power | | | 158.7 | MW |
| | ST losses | | | -1.6 | MW |
| | Net ST output | | | 157.1 | MW |
| Generator losses | | -11.5 | MW | | |
| Balance of Plant losses | | -7.1 | MWe | | |
| | Boiler feed water pumps | | | -2.8 | MWe |
| | Cooling water pumps | | | -3.6 | MWe |
| | Condensate pumps | | | 0.0 | MWe |
| | Remaining losses (0.1%) | | | -0.7 | MWe |
| | BOP losses | | | -7.1 | MWe |
| Total Plant net power | | 664.3 | MWe | | |
| Net electrical efficiency | | 47.3 | % | | |
| Steam supply to $CO_2$ capture plant(@ 4.6 bar, 318°C) | | 309.6 | t/hr | | |

***Table 5.6 - Case 1 Power Plant Energy Balance***

### 5.2.3 Capture Plant Description

The Capture Plant captures $CO_2$ after combustion from the exhaust gas from the CCPP. The exhaust gas from the CCPP is first cooled in a water quench where most of the steam in the flue gas is condensed. The cooled exhaust gas is fed to the $CO_2$ absorber where $CO_2$ is scrubbed from the exhaust gas by an amine solution. The $CO_2$ lean flue gas is then vented. The rich amine solution is regenerated by thermal stripping, and the captured carbon dioxide is compressed and dried for export.

**Quench**

The gas turbine exhaust leaving the HRSG is both too hot, (typically 100°C) and it contains too much steam to be fed directly to the $CO_2$ absorber. The quench column both cools the exhaust stream to near ambient and condenses most of the steam.

The quench column is a large packed tower in which a large amount of water which cascades down the packing. The gas turbine exhaust flows up the quench column and is cooled by direct contact cooling. A significant volume of circulating water is required to contact the exhaust gas to remove the sensible and latent heat.

The water from the bottom of the quench column is cooled against sea water in the quench water cooler and returned to the top of the quench column. The excess water, condensed from the gas turbine exhaust gas, is purged and sent to waste water treatment.

The cooled gas turbine exhaust leaves the top of the quench column at 38°C and is then blown to the $CO_2$ absorber column by the absorber feed fan.

**Acid Gas Removal**
Carbon dioxide is removed from the cooled gas turbine exhaust by scrubbing with MEA. The carbon dioxide is absorbed into the amine solution, which is then regenerated in a stripping column where the carbon dioxide is stripped from the amine solution with steam. The performance data for the stripper unit was obtained from vendor data for this study.

The flue gas is blown from the absorber feed fan to the bottom of the absorber column. It flows up the packed column against a down flowing aqueous solution of MEA. The solution is "lean" in carbon dioxide content and enters the column at 34° C. The carbon dioxide is absorbed from the gas turbine exhaust, making a 'rich' solution, which leaves the bottom of the absorber column.

The gas turbine exhaust, after having any droplets of MEA washed out of it in a demin water wash section at the top of the column, leaves at 42°C, lean in carbon dioxide.

The absorbed carbon dioxide is stripped from the rich solution in the stripper column. The rich solution is pumped from the bottom of the absorber column and is then heated to 107°C in the rich/ lean exchanger. The hot rich solution passes to the top of the stripping column and flows down against an upflow of steam that desorbs the carbon dioxide from the solution. The steam is generated in the stripper reboiler from the water in the amine solution. Heat for the stripper reboiler is supplied by low pressure steam from the CCPP HRSG.

The carbon dioxide, together with some steam, exits the top of the column at 112°C and passes to the stripper condenser where it is cooled to 70°C, condensing most of the steam. The remaining vapour flows into the stripper trim condenser where it is cooled to 22°C against sea water. Condensate is collected after each condenser in knock out drums and is then pumped by the stripper reflux pump back to the top of the stripping column.

The MEA solution leaves the bottom of the stripping column at 125°C, lean in carbon dioxide, and passes through the rich / lean exchanger. It is then pumped by the lean amine pump through the lean amine air cooler and then the lean amine trim cooler where it is cooled to 38°C against sea water. Finally the lean amine is returned to the top of the absorber column.

**$CO_2$ Compression and Drying**
The $CO_2$ removed in the acid gas removal unit is compressed to 22 bar(g), dried using a molecular sieve and compressed again to 110 bar(g) for export. The molecular sieve is regenerated using hot process water from the gas treatment section in a "no loss" configuration, which recycles the regeneration off gas back to the $CO_2$ compressor.

The $CO_2$ compressor is an 8-stage integral gear machine with full intercooling after stages 1 to 5, partial intercooling after stage 6 and no intercooling after stage 7.

**Cooling Water**
Seawater, from a new intake, is circulated once through major coolers and condensers and then discharged directly back to the sea. A secondary fresh water system is used for smaller coolers and machinery.

**Water Treatment**
The water treatment plant treats the quench water purge and produces demin water make-up for the acid gas removal unit.

A small quantity of sludge is produced for disposal offsite.

### 5.2.4 Capture Plant Performance

*Table 5.7* shows the performance of the capture plant in case 1. There is no fuel input in this case, neither there is syngas output. The capture plant does require an amount of electricity for the process, next to the steam import from the CCPP (which is not shown in the table).
A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The $CO_2$ capture efficiency is calculated by taking the actual $CO_2$ emission, compensate for the $CO_2$ in the inlet air to the gas turbine, and divide this by the maximum $CO_2$ emission from burning the original fuel (before reforming).

| **$CO_2$ Capture Plant Energy Balance** | | |
|---|---|---|
| Capture Plant Fuel Energy Input (LHV) | - | MWth |
| Capture Plant Syngas Output (LHV + Heat) | - | MWth |
| | | |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -38.5 | MWe |
| $CO_2$ Capture Plant Power Production | - | MWe |
| Capture Plant Net Power Output | -38.5 | MWe |
| | | |
| $CO_2$ Capture Efficiency | 85.7 | % |

***Table 5.7 - Case 1 Energy Balance Capture Plant***

### 5.2.5 Overall Plant Balance

The energy balance for the post combustion $CO_2$ capture power plant is shown in *Table 5.8*. The net power production decreased in comparison with the reference case. This is caused by the decreased production in the CCPP because of steam extraction to the capture plant and by the electrical power consumption in the capture plant.

| **Total Overall Plant Energy Balance** | | |
|---|---|---|
| Total Overall Plant Energy Input (LHV) | 1404.6 | MWth |
| | | |
| Combined Cycle Power Plant Net Electrical Output | 664.3 | MWe |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -38.5 | MWe |
| $CO_2$ Capture Plant Power Production | 0.0 | MWe |
| Total Overall Plant Net Power Output | 625.9 | MWe |
| | | |
| Net Overall Plant Electrical Efficiency | 44.6 | % |

***Table 5.8 - Case 1 Overall Plant Energy Balance***

## 5.3 CASE 2-1: PRE COMBUSTION $CO_2$ CAPTURE BY LOCAL $H_2$ PRODUCTION FROM NATURAL GAS

In case 2-1, capture is effected by removing the carbon from natural gas fuel before combustion. This carbon removal is done in the $CO_2$ Capture Plant, after which the carbon-free syngas is fed to the gas turbine. This syngas has a significantly lower heating value compared with natural gas. Firing this fuel will require modifications to the gas turbines.
The Capture Plant is located at or near the power plant plot and therefore this case is a “local” case, in contrast to case 2-2, at which the Capture Plant is located at 40 km distance from the CCPP (remote case).
The capture plant is located upstream of the CCPP, see *Figure 5.2*.

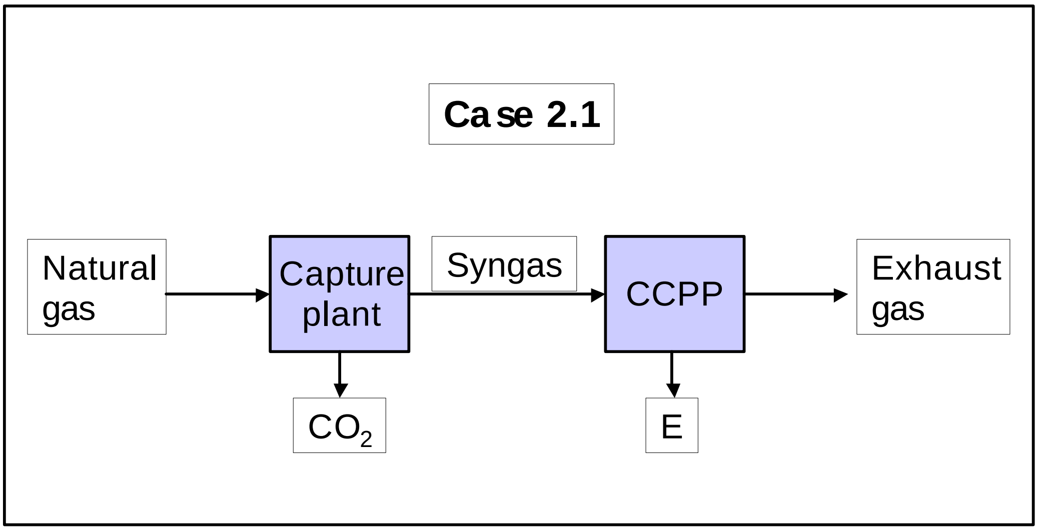



***Figure 5.2 - Case 2-1 Scheme***

### 5.3.1 Capture Plant Description

This section is to be read in conjunction with the process block diagram for case 2-1 and the mass balance for case 2-1, P03-2101.

The Capture Plant converts a feed of natural gas to a fuel gas mixture of hydrogen and nitrogen. First the gas is led through a desulphurisation section in which the $H_2S$ in the natural gas is captured by using a bed of ZnO. After desulphurisation the Capture Plant consists of a reforming stage, where a mixture of natural gas with steam and air is converted to synthesis gas, or syngas, which is a mixture of $H_2$, CO, $CO_2$ and $N_2$. The reformer is followed by two stages of shift reaction, where the carbon monoxide and residual steam are converted to hydrogen and carbon dioxide. The reaction stages are followed by the removal of $CO_2$ from the shifted syngas, using a chemical solvent, and delivery of the fuel gas to battery limits. The $CO_2$ is regenerated from the solvent and compressed for delivery to battery limits for subsequent disposal. The resulting hydrogen rich syngas is saturated with water to control $NO_x$ formation during combustion in the gas turbines.

The Capture Plant recovers waste heat from the high temperature sections of the process by generating high-pressure superheated steam. Some of this steam is used in the process and the remainder is used to generate electricity, which is used within the plant. For the remaining electricity demand, additional electricity is imported from the external grid.

**Auto-Thermal Reformer**
Natural gas is first pre-heated to 380°C and passed through a desulphurisation reactor where all of the sulphur components are converted to $H_2S$, which is then absorbed. The reforming and shift catalysts can easily be poisoned by sulphur and therefore only a very low level (less than 1 ppm) can be tolerated.

The gas is then mixed with process steam, sufficient to give a steam to carbon ratio of 1.0, heated further and passed to an air-blown auto-thermal reformer (ATR). In the ATR, the natural gas is sub-stoichiometricly combusted with air. It is then passed over a high temperature reforming catalyst, which promotes the formation of synthesis gas according to the following reactions:

Partial Oxidation of Higher Hydrocarbons

$$C_xH_y + {}^1\!/_2 O_2 \rightarrow xCO + {}^y\!/_2 H_2$$

Partial Oxidation of Methane

$$CH_4 + {}^1\!/_2 O_2 \rightarrow CO + 2H_2$$

Steam Reforming of Methane

$$CH_4 + H_2O \Leftrightarrow CO + 3H_2$$

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

The high temperature of partial oxidation maximises reforming of the gas and minimises its methane content.

**High Temperature Cooling**
The syngas stream leaves the ATR at 950°C, and it is cooled by raising and superheating high pressure steam and by preheating the feed stream to the ATR.

**CO Shift**
The syngas from the ATR contains 14 mol%(dry) CO which must be converted to $CO_2$ in order to facilitate the removal of carbon. This conversion is carried out in two shift

reactors, namely the high-temperature and the low-temperature (HT shift and LT shift). The shift reaction is exothermic and the heat of reaction is recovered after the HT shift reactor by raising more HP steam and by preheating the boiler feed water.

**Cooling and Condensation**
The enthalpy of the syngas exiting the LT Shift provides heat for the saturator, heating of the fuel gas product and preheating of demineralised water feed to the deaerator. The gas stream is finally cooled to 50°C in an air cooler and fed to the $CO_2$ absorber in the acid gas removal unit. The condensate is separated from the syngas and the dissolved gases are stripped out in the steam system.

**Acid Gas Removal**
The $CO_2$ absorber is a two-stage counter-current column where the $CO_2$ rich syngas is contacted first with a “semi-lean” solution of MDEA solvent, then with a “lean” solution to absorb the carbon dioxide, leaving the hydrogen/nitrogen fuel gas.

The $CO_2$–rich stream leaving the bottom of the absorber is regenerated by depressurisation in three stages. In the first stage the liquid stream passes to the HP flash column where the pressure is reduced from about 30 bar(g) to about 5.5 bar(g), allowing $CO_2$ gas to flash off. The liquor then passes to the LP flash column, which operates at about 0.2 bar(g), where further flashing takes place and some stripping as the liquid passes through a packed bed counter-current with the vapour stream from the final stage. At the bottom of this column the liquid is sufficiently “lean” to be recycled to the absorber as “semi-lean” solvent.

Approximately 85% of the liquid from the LP flash column is recycled to the absorber, while the remaining 15% passes to the third stage of regeneration. This stage is a reboiled stripper column, where the liquid is contacted with steam in a packed bed. The steam is generated by boiling some of the water present in the MDEA solution. The liquor from the bottom of the column is sufficiently low in $CO_2$ to be recycled to the absorber as “lean” solution. The vapour overhead from the stripper column passes through the LP flash column, as described above, and is cooled in the LP flash column condenser. The off-gas from the condenser passes to the $CO_2$ compressor.

**$CO_2$ Compression**
The $CO_2$ removed in the acid gas removal unit is compressed to 22 bar(g), dried using a molecular sieve and compressed again to 110 bar(g) for export. The molecular sieve is regenerated using hot process water from the gas treatment section in a “no loss” configuration, which recycles the regeneration off gas back to the $CO_2$ compressor.

**Gas Conditioning**
Carbon dioxide free syngas from the top of the $CO_2$ absorber is heated and passed to a saturator to raise the water content, which together with the nitrogen present, are sufficient to control $NO_x$ formation in the gas turbine combustor to 25 ppmvd. It is then superheated to 230°C against circulating demineralised water, before being sent to the local combined cycle power plant at 27.5 bar(g).

**Steam System**
Superheated steam is generated at 122 bar(g) by heat recovery from the ATR product gas stream. The outlet steam from the first stage, at 37 bar(g), is reheated by heat exchange with the ATR product gas stream. Part of this steam is used to strip the process condensate of the dissolved gases and the whole stream is fed to the ATR as process steam. The remainder of the 37 bar(g) superheated steam passes to the second stage of the turbine. Pass out steam is taken from the second stage of the turbine and condensed at 2.5 bar(g) to provide reboil for the stripper column in the acid gas removal unit. The remainder of the steam passes to the condensing stage of the turbine.

Condensate from the final stage of the turbine passes to a deaerator for eventual recycle to the HP boiler. Process condensate separated from the syngas during cooling is also recycled after passing through a stripping column to remove dissolved process gases. A make-up stream of demineralised water is fed to the deaerator to replace the process steam consumed in the reformer.

**Power Block**
The superheated steam raised in the high temperature cooling is fed to a 3-stage condensing steam turbine in the power block. The power generated is used for onsite consumption.

**Cooling Water**
Seawater, taken from a dedicated intake, is circulated once through the major coolers and condensers and discharged directly back to the sea through a dedicated discharge system. A secondary fresh water system is used for smaller coolers and machinery.

### 5.3.2 Capture Plant Performance

*Table 5.9* shows the performance of the capture plant. The fuel input in MW is given, based on the LHV value of the feedstock. The fuel output is presented in MW, which is based on LHV of the produced syngas plus the sensible heat of the syngas. This is important in the local cases as the fuel is heated to around 230 ºC, which gives a significant part of the heat input to the gas turbine.
Furthermore the net electricity consumption is presented, which exists from the consumed electricity for all power consumers minus the electricity production from the power block of the capture plant.
A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The $CO_2$ capture efficiency is calculated by taking the actual $CO_2$ emission, compensate for the $CO_2$ in the inlet air to the gas turbine, and divide this by the maximum $CO_2$ emission from burning the original fuel (before reforming).

| $CO_2$ Capture Plant Energy Balance | | |
|---|---|---|
| Capture Plant Fuel Energy Input (LHV) | 1672.4 | MWth |
| Capture Plant Syngas Output (LHV + Heat) | 1417.3 | MWth |
| | | |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -158.9 | MWe |
| $CO_2$ Capture Plant Power Production | 43.0 | MWe |
| Capture Plant Net Power Output | -115.9 | MWe |
| | | |
| $CO_2$ Capture Efficiency | 85.6 | % |

***Table 5.9 - Case 2-1 Capture Plant Energy Balance***

### 5.3.3 CCPP Description

The overall process flow scheme of the power plant is not modified with respect to the reference power plant. However modifications are required to the gas turbines to enable the firing of a fuel with a significantly lower heating value. The different fuel also has a large impact on the gas turbine control and the process parameters of the power plant.

Main process modifications to the reference CCPP are:

- Replacement of gas turbine Dry Low $NO_x$(DLN) combustion system by a conventional dual fuel(natural gas and syngas) system provided with steam injection for $NO_x$ abatement.
- Tie-in in MP steam system for steam supply to the gas turbine steam injection system. A steam injection system is needed in all cases, to limit $NO_x$ emissions when the unit is operated on the back-up fuel (natural gas).
- Demin water plant capacity to be enlarged for steam injection or additional demin water plant needed.

Because of the high hydrogen content in the fuel it is not possible to use a DLN combustion system. This means that the DLN combustors need to be removed and replaced by conventional combustors. To keep the $NO_x$ emissions within the limit of 25 ppmv (dry @15%$O_2$), it is necessary to prepare the fuel composition with diluents, e.g. by adding N2 or by applying steam injection. Both methods decrease the flame temperature and limit the thermal $NO_x$ formation.

When feeding the gas turbine with the same fuel input as in the natural gas application, the fuel mass flow into the gas turbine increases significantly when firing low LHV fuel. In order to keep the compression ratio of the gas turbine at design level in order to avoid potential compressor surge, the expander inlet flow should be kept at design level as well. This is realised by decreasing the inlet air flow. This is achieved by controlling the Inlet Guide Vanes (IGV's), which can be partly shut to decrease the air intake.

The consequence of decreasing the inlet flow to the GT compressor by IGV control is a decrease in the amount of compressor work. The turbine still receives the same flow as in the design case, because of the increased fuel flow. These effects result in an increase in the overall gas turbine power output.

Information from GE showed that the maximum net electrical power output of their frame 9 gas turbine is limited to 286 MWe (design value = +/- 260 MWe). Therefore it is necessary to lower the combustor exit temperature in order to control the power output.

To increase the efficiency of the power plant it can be feasible to apply fuel preheating when the gas turbine is fired on natural gas. Fuel preheating increases the sensible heat input to the combustion chamber and reduces the amount of fuel energy needed (and therefore the fuel consumption). The heat for fuel heating is usually taken from the steam cycle, which will cost some electrical power (as this is not available for expansion in the steam turbine). The overall effect on net electrical efficiency is however positive.
When the gas turbine is fired on a low-LHV fuel, the positive effect of fuel heating increases significantly. This is the consequence of the much higher fuel flow to the combustion chamber. Fuel preheating should therefore be applied with these kinds of fuels.
The fuel is delivered from the fuel processing plant already at a temperature of 230 ºC. The fuel is not preheated to a higher temperature, and this should be considered as an option for optimization.

### 5.3.4 CCPP Performance

*Table 5.10* below shows the gas turbine parameters fired on the low-LHV syngas in comparison to the gas turbine parameters when fired on natural gas.

| **Case** | **Reference Case** | **Case 2-1** |
|---|---|---|
| Fuel LHV | 46,855 kJ/kg | 7,476 kJ/kg |
| Fuel Flow / Temperature | 15.0 kg/s / 10 ºC | 89.7 kg/s / 230 ºC |
| Steam Injection Flow / Temperature | - | - |
| Air Inlet Flow | 618 kg/s | 535 kg/s |
| Combustor Exit Temperature | 1352 ºC | 1270 ºC |
| Exhaust flow / Temperature | 633 kg/s / 608 ºC | 625 kg/s / 565 ºC |
| Net Power Output | 258.8 MW | 286.0 MW |
| Net Electric Efficiency (LHV) | 36.8 % | 42.6 % |

***Table 5.10 - Case 2-1: Gas Turbine performance***

The table shows that the net electric power output of the gas turbine increases to 286 MWe, which is an increase of almost 11%. This 286 MWe is the maximum net power output for this gas turbine, according to information provided by General Electric. The exhaust gas flow rates are similar but due to the lower Combustor Exit Temperature the exhaust gas temperature has decreased to 565 ºC. This means that the HRSG section will work at different flue gas conditions. The low-LHV fuel will influence the performance of the steam cycle. Off-design calculations show that the HRSG and steam turbine can operate properly at the given conditions without modifications.

The following table shows the overall energy balance for the combined cycle power plant.

| **Power Plant Energy Balance** | | | | | |
|---|---|---|---|---|---|
| Gas Turbine Energy Input | | 1417.3 | MWth | | |
| | Fuel Consumption LHV | | | 1341.6 | MWth |
| | Fuel Sensible Heat Input (Tref. 15 ºC) | | | 75.7 | MWth |
| | Total Gas Turbine Energy Input | | | 1417.3 | MWth |
| Gas Turbine | | 581.2 | MW | | |
| | GT Gross power | | | 609.7 | MW |
| | GT losses | | | -28.6 | MW |
| | Net GT output | | | 581.2 | MW |
| Steam Turbine | | 252.0 | MW | | |
| | ST Shaft power | | | 254.5 | MW |
| | ST losses | | | -2.5 | MW |
| | Net ST output | | | 252.0 | MW |
| Generator losses | | -14.2 | MW | | |
| Balance of Plant losses | | -9.3 | MWe | | |
| | Boiler feed water pumps | | | -2.6 | MWe |
| | Cooling water pumps | | | -5.7 | MWe |
| | Condensate pumps | | | -0.2 | MWe |
| | Remaining losses (0.1%) | | | -0.8 | MWe |
| | BOP losses | | | -9.3 | MWe |
| Total Plant net power | | 809.6 | MWe | | |
| Net electrical efficiency | | 57.1 | % | | |

***Table 5.11 - Case 2-1 Energy Balance Power Plant***

The mass and heat balance for the most important streams are shown in Appendix 1.

### 5.3.5 Overall Plant Performance

The overall energy balance for the combined $CO_2$ capture plant and CCPP is shown in *Table 5.12*, which combines the results from *Table 5.9* and *Table 5.11*.

| **Total Overall Plant Energy Balance** | | |
|---|---|---|
| Total Overall Plant Energy Input (LHV) | 1672.4 | MWth |
| | | |
| Combined Cycle Power Plant Net Electrical Output | 809.6 | MWe |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -158.9 | MWe |
| $CO_2$ Capture Plant Power Production | 43.0 | MWe |
| Total Overall Plant Net Power Output | 693.7 | MWe |
| | | |
| Net Overall Plant Electrical Efficiency | 41.5 | % |

***Table 5.12 - Case 2-1 Overall Plant Energy Balance***

## 5.4 CASE 2-2: PRE COMBUSTION $CO_2$ CAPTURE BY REMOTE $H_2$ PRODUCTION FROM NATURAL GAS

Case 2-2 is similar to case 2-1, except for the fact that the fuel processing plant is located at 40 km distance from the power plant plot. The syngas is transported through pipelines from the fuel plant to the power plant, see *Figure 5.3*.

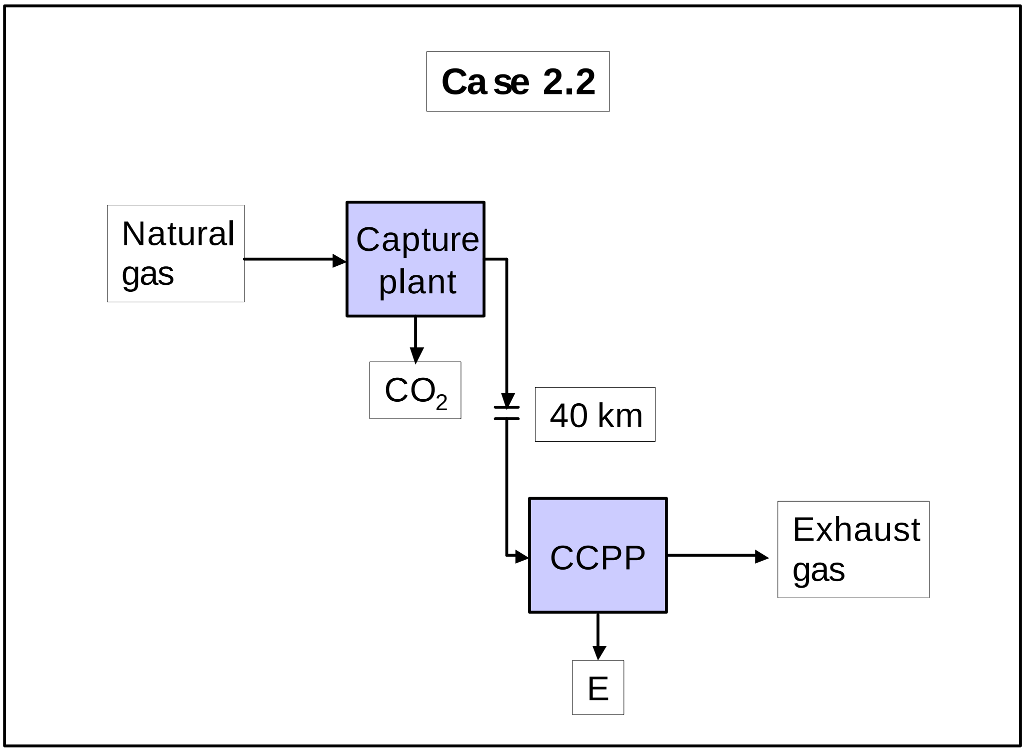



***Figure 5.3 - Case 2-2 Scheme***

### 5.4.1 Capture Plant Description

This section is to be read in conjunction with the process block diagram for case 2-2 and the mass balance for case 2-2 P03-2201.

The Capture Plant converts natural gas to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon monoxide in the syngas is then converted to carbon dioxide and more hydrogen in a series of catalytic reactors. The $CO_2$ is removed by an absorbent solution and the resultant hydrogen rich syngas is compressed, dried and exported from the site at ambient temperature for piping to the CCPP. $NO_x$ formation on combustion in the CCPP is controlled by direct injection of steam taken from the CCPP steam cycle. The captured $CO_2$ is dried and compressed before being exported from the Capture Plant site.

Most of the process steps are equal to the process steps in case 2-1 and will not be repeated. The items that are different are described here.

**Auto Thermal Reformer**
Reference is made to paragraph 5.3.1.

**High Temperature Cooling**
Reference is made to paragraph 5.3.1.

**CO Shift**
Reference is made to paragraph 5.3.1.

**Cooling and Condensation**
Reference is made to paragraph 5.3.1.

**Acid Gas Removal**
Reference is made to paragraph 5.3.1.

**$CO_2$ Compression**
Reference is made to paragraph 5.3.1.

**Gas Conditioning**
Carbon dioxide free syngas from the top of the $CO_2$ absorber in the AGR is dried and compressed to 39 bar(g) in order to transfer the fuel to the remote combined cycle power plant.

In the CCPP steam is added to the fuel gas for $NO_x$ control and then the combined fuel gas stream is heated using steam to 230°C before being fed to the gas turbine combustors.

**Steam System**
Reference is made to paragraph 5.3.1.

**Power Block**
Reference is made to paragraph 5.3.1.

**Cooling Water**
Seawater, from a new intake, is circulated once through major coolers and condensers and discharged directly back to the sea. A secondary fresh water system is used for smaller coolers and machinery.

**Fuel Gas Pipeline**
The 40 km pipeline for the transportation of fuel gas between the Capture Plant and the CCPP site is made of carbon steel. No special metallurgy is required, as the fuel gas is dried before transportation. The line size is 36 " and the fuel gas inlet and outlet pressures are respectively 39.0 barg and 30.6 barg.

### 5.4.2 Capture Plant Performance

*Table 5.13* shows the performance of the capture plant in case 2-2. In comparison with the performance of the capture plant of case 2-1, which is shown in *Table 5.9*, a few differences can be recognised.
The syngas output in MW is lower, while the feedstock input in MW is approximately the same. This can be explained by the fact that however the syngas mass flows are similar, in case 2-2 the syngas leaves the fuel plant at low temperature, i.e. the sensible heat content is almost zero. The fuel preheating in this case takes place in the CCPP, and will cause a loss in power production there. Because the fuel is not preheated in the capture plant, more heat is available for power production in the power block, and this results in a higher capture plant power production in comparison to case 2-1.
The power consumption has increased, which is a direct consequence of the need for compressing the syngas, so that it can be transported through the 40 km pipeline to the CCPP plot. A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The $CO_2$ capture efficiency is calculated by taking the actual $CO_2$ emission, compensate for the $CO_2$ in the inlet air to the gas turbine, and divide this by the maximum $CO_2$ emission from burning the original fuel (before reforming).

| **$CO_2$ Capture Plant Energy Balance** | | |
|---|---|---|
| Capture Plant Fuel Energy Input (LHV) | 1671.0 | MWth |
| Capture Plant Syngas Output (LHV + Heat) | 1344.7 | MWth |
| | | |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -168.0 | MWe |
| $CO_2$ Capture Plant Power Production | 71.1 | MWe |
| Capture Plant Net Power Output | -96.9 | MWe |
| | | |
| $CO_2$ Capture Efficiency | 85.7 | % |

***Table 5.13 - Case 2-2 Energy Balance Capture Plant***

### 5.4.3 CCPP Description

The fuel is delivered at the power plant at a low temperature of 21.5 ºC (compared to a temperature of 230 ºC in the local case 2-1). This is due to the 40 km transportation distance between the two sites.
In paragraph 5.3.3 it was stated that preheating the fuel is a feasible option to increase the overall efficiency of the power plant. In this case the heat for the fuel preheating is supplied from the CCPP steam system.

Main process modifications to the reference CCPP are:

- Replacement of gas turbine Dry Low $NO_x$(DLN) combustion system by a conventional dual fuel(natural gas and syngas) system provided with steam injection for $NO_x$ abatement.
- Tie-in in MP steam system for steam supply to the gas turbine steam injection system
- Pre-mix system for mixing syngas with MP steam

- Demin water plant capacity to be enlarged for steam injection or additional demin water plant needed

To avoid $NO_x$ emissions above permitted levels it is necessary to add extra diluents to the fuel. It is possible to do this at the fuel processing plant, but this would mean that the extra diluent is transported together with the fuel over 40 km of pipeline. When the diluent is added at the power plant plot, the extra compression energy is avoided. At the power plant plot, steam is available as diluent. The steam is injected directly into the gas turbine combustion chamber, without premixing it with the fuel. In the combined cycle power plant in this study, IP steam of about 330 ºC @ 27 bara is available for steam injection.

In this study the fuel is preheated until the temperature of the mixture of fuel and steam is about 230 ºC. At this temperature no extra measures need to be taken to materials in the existing equipment. The temperature level can be subject to optimization, as this is not considered in this study.

### 5.4.4 CCPP Performance

*Table 5.14* shows the gas turbine performance for case 2-2 in comparison to the reference case.

| Case | Reference Case | Case 2-2 |
|---|---|---|
| Fuel LHV | 46,855 kJ/kg | 8,622 kJ/kg |
| Fuel Flow / Temperature | 15.0 kg/s / 10 ºC | 77.9 kg/s / 215 ºC |
| Steam Injection Flow / Temperature | - | 12.0 kg/s / 337 ºC |
| Air Inlet Flow | 618 kg/s | 536 kg/s |
| Combustor Exit Temperature | 1352 ºC | 1268 ºC |
| Exhaust flow / Temperature | 633 kg/s / 608 ºC | 626 kg/s / 564 ºC |
| Net Power Output | 258.8 MW | 288.8 MW |
| Net Electric Efficiency (LHV) | 36.8 % | 42.6 % |

***Table 5.14 - Case 2-2 gas turbine performance***

The following table shows the energy balance for the complete combined cycle power plant.

| Power Plant Energy Balance | | | | | |
|---|---|---|---|---|---|
| Gas Turbine Energy Input | | 1344.7 | MWth | | |
| | Fuel Consumption LHV | | | 1343.0 | MWth |
| | Fuel Sensible Heat Input (Tref. 15 ºC) | | | 1.8 | MWth |
| | Total Gas Turbine Energy Input | | | 1344.7 | MWth |
| Gas Turbine | | 580.7 | MW | | |
| | GT Gross power | | | 609.3 | MW |
| | GT losses | | | -28.6 | MW |
| | Net GT output | | | 580.7 | MW |
| Steam Turbine | | 204.9 | MW | | |
| | ST Shaft power | | | 207.0 | MW |
| | ST losses | | | -2.1 | MW |
| | Net ST output | | | 204.9 | MW |
| Generator losses | | -13.3 | MW | | |
| Balance of Plant losses | | -8.1 | MWe | | |
| | Boiler feed water pumps | | | -2.4 | MWe |
| | Cooling water pumps | | | -4.7 | MWe |
| | Condensate pumps | | | -0.2 | MWe |
| | Remaining losses (0.1%) | | | -0.8 | MWe |
| | BOP losses | | | -8.1 | MWe |
| Total Plant net power | | 764.3 | MWe | | |
| Net electrical efficiency | | 56.8 | % | | |

***Table 5.15 - Case 2-2 Energy Balance Power Plant***

When *Table 5.15* is compared to the case 2-1 performance, the decreased steam turbine power generation attracts the attention. This is caused by the fact that steam is used to preheat the syngas fuel at the CCPP plot. This steam is extracted from the CCPP steam cycle and is no longer available for expansion in the LP steam turbine section. Therefore the power generation from the steam turbine is lower than in the local case. The amount of heat which is transferred to the fuel by preheating is equal to 58.2 MWth.

The mass and heat balance for the most important streams are shown in Appendix 2.

### 5.4.5 Overall Plant Performance

The overall energy balance for the combined $CO_2$ capture plant and power plant is shown in *Table 5.16*, which is a combination of *Table 5.13* and *Table 5.15*.

| **Total Overall Plant Energy Balance** | | |
|---|---|---|
| Total Overall Plant Energy Input (LHV) | 1671.0 | MWth |
| | | |
| Combined Cycle Power Plant Net Electrical Output | 764.3 | MWe |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -168.0 | MWe |
| $CO_2$ Capture Plant Power Production | 71.1 | MWe |
| Total Overall Plant Net Power Output | 667.4 | MWe |
| | | |
| Net Overall Plant Electrical Efficiency | 39.9 | % |

***Table 5.16 - Case 2-2 Overall Plant Energy Balance***

## 5.5 CASE 3-1: PRE COMBUSTION $CO_2$ CAPTURE BY LOCAL $H_2$ PRODUCTION FROM COAL

In case 3-1, capture is effected by removing the carbon from the Coal feedstock before combustion. The Capture Plant converts the coal by partial oxidation (gasification) to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. After capture of $CO_2$ the carbon-free syngas is fed to the gas turbine, see *Figure 5.4*. In case 3-1 the capture plant is located at or near the power plant plot, in comparison to case 3-2 where the capture plant is located at 40 km distance from the power plant.

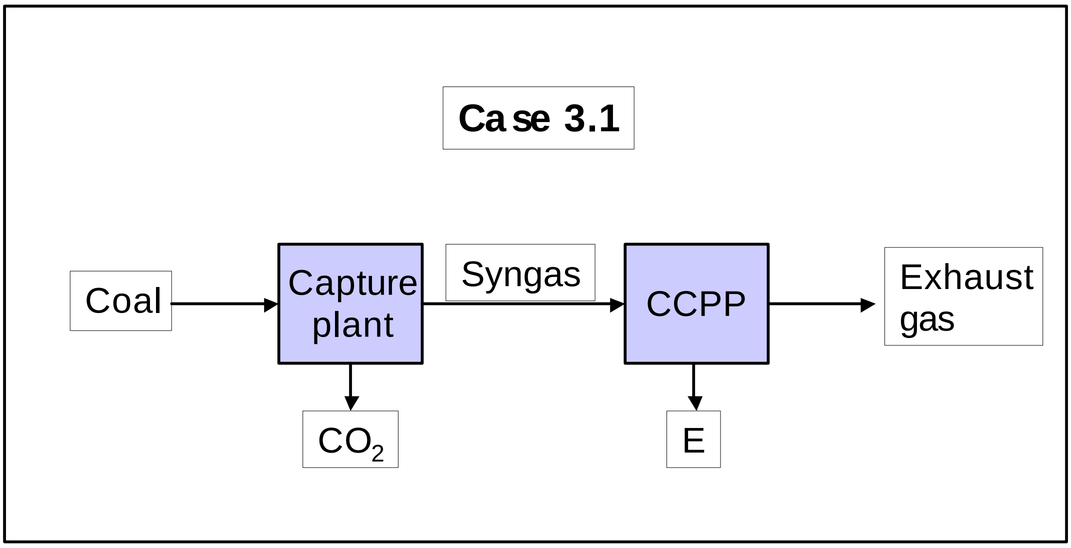



***Figure 5.4 - Case 3-1 Scheme***

### 5.5.1 Capture Plant Description

The Capture Plant converts a feed of coal to a fuel gas mixture of hydrogen and nitrogen suitable for a gas turbine. The plant consists of a gasification stage where a mixture of coal and water is partially oxidised with oxygen from an air separation unit (ASU). The synthesis gas, or syngas, which is a mixture of $H_2$, CO, $CO_2$ and $N_2$ produced in the gasification unit, is fed to a CO shift reactor, where the carbon monoxide and residual steam are converted to $H_2$ and $CO_2$. The $CO_2$ and $H_2S$ are removed from the shifted syngas, using a physical solvent, and then the pressure of the hydrogen rich fuel gas is reduced to gas turbine inlet pressure through an expander. The fuel gas is heated before and after the expander to increase the overall efficiency of the Capture Plant. The hydrogen rich fuel gas has nitrogen added to reduce $NO_x$ formation during combustion in the gas turbines. Nitrogen from the ASU is compressed, heated and injected directly into the combustors of the CCPP for $NO_x$ control.

The $CO_2$ is regenerated from the solvent, dried and compressed for delivery to battery limits for subsequent disposal. An $H_2S$ rich gas stream is reacted with oxygen in a Claus Unit to form a solid sulphur product.

The waste heat from the Capture Plant is used to generate steam, which is superheated in the HRSG of a small gas turbine for generation of electric power for internal use. Additional electricity is imported from the grid.

This section is to be read in conjunction with the process block diagram for case 3-1 and the mass balance for case 3-1 P03-3101.

**ASU**

Oxygen for the gasification and Claus units is separated from air in a cryogenic air separation unit (ASU). The nitrogen is used to dilute the fuel gas for $NO_x$ control. The ASU is operated at low pressure and all of the feed air is supplied by dedicated air compressors driven by electric motors.

The oxygen is pumped to high pressure as a cryogenic liquid to remove the requirement for an oxygen compressor and vaporised against a stream of condensing high pressure air within the ASU main heat exchanger. The gaseous oxygen, at a purity of 95 vol%, is preheated with low pressure steam before being fed to the gasifier at 79 bar(g).

A small side stream is taken off at low pressure for the burners in the Claus unit. The majority of the product nitrogen stream, which contains less than 10 ppm $O_2$, is compressed, and some is added to the fuel gas stream to reduce the hydrogen content with the majority injected directly into the combustors of the gas turbines for $NO_x$ control. Some additional nitrogen is used in concentrating the $H_2S$ in the Selexol unit, a small amount is used for purging and inerting, and the remainder is used internally within the ASU.

**Coal Storage and Preparation**

Coal is delivered to the site and stored in a stockpile normally sized for 3 days operation at full load. There is also an inactive coal storage pile sized for 30 days storage.

The coal is crushed and slurried with process water to 66 wt% and then pumped to one of a pair of day storage tanks. From the storage tank the slurry is pumped to 68 bar(g) and delivered to the gasifier.

**Gasification**

The coal slurry is gasified in a high pressure, top fired, ChevronTexaco gasifier fitted with a water quench. The temperature in the gasifier is sufficient to melt all the ash to slag. The coal is converted to synthesis gas, or syngas containing primarily $H_2$ and CO, together with some steam, $CO_2$, $N_2$, $CH_4$, and Ar. The sulphur in the coal is converted to $H_2S$ with some COS; other sulphur containing compounds are not considered in this study. The chlorine in the coal is converted to HCl. Small amounts of HCN and $NH_3$ are also produced. A small amount of carbon remains as soot.

The syngas, slag and soot exit from the bottom of the gasifier and are passed at 63 bar(g) to a water quench for cooling. The solids are removed through a lock-hopper system at the bottom of the quench, and the syngas, now saturated with water vapour, leaves at the top of the quench chamber. To prevent the build-up of soluble

compounds, a blowdown stream, called black water, is taken from the quench, cooled in a cascade of flash drums at decreasing pressure and sent to the waste water treatment unit.
The saturated syngas is scrubbed with filtered process water, recycled from the bottom of the desaturator to remove particulates and then passed to the gas processing section. The scrubber water together with more process water is fed to the quench as make-up.

**CO Shift**
The scrubbed syngas is heated to above 290°C and passed to the sour shift reactor where most of the CO is converted to $CO_2$ over a catalyst according to the reaction:

Water Gas Shift

$$CO + H_2O \Leftrightarrow CO_2 + H_2$$

At the same time most of the COS is converted to $H_2S$ and HCN to $NH_3$ according to the reactions:

$$COS + H_2O \Leftrightarrow CO_2 + H_2S$$

and

$$HCN + H_2O \Leftrightarrow NH_3 + CO$$

The shift reaction is exothermic and the shifted syngas exits the reactor at above 430 °C.

**Cooling and Condensation**
The syngas from the outlet of the shift reactor is cooled initially by raising HP (135 bar(g)) steam. It is further cooled against the inlet stream to the shift reactor and then against demineralised water. Some of this water is used as BFW, and the remainder is circulated to the back of the plant to provide preheat to the expander and gas turbine. Final cooling and condensation is carried out in a desaturator.

The desaturator is a direct contact gas / liquid exchanger which consists of a packed or trayed column down which a liquid (water in this case) flows against a condensing gas steam passing upwards. The main effect is to preheat the condensate against the incoming hot gas.

Some of the hot water from the bottom of the desaturator is recycled to the quench / scrubber as make-up. The balance is used to raise LP steam, and to provide reboil duty for the sulphur removal unit before the majority is recycled back to the centre section of the desaturator. The remainder is then cooled by preheating incoming BFW. A small stream is fed to the coal preparation unit for coal slurrying, and the remainder is used as a cold water recycle to the desaturator.

In this way, the syngas is c0ooled to below 40°C, without the use of cooling water, before being fed to the $H_2S$ absorber in the AGR unit.

The HP and LP process steam is sent to the power block for superheating in the HRSG's before passing to the steam turbine.

**Acid Gas Removal**
The sulphur compounds and $CO_2$ are removed from the syngas in two stages. First, the sulphur compounds are removed in an $H_2S$ absorber, and then syngas passes to a $CO_2$ absorber where the $CO_2$ is removed.

The $CO_2$ absorber is in two stages. Lean Selexol liquor from the stripper column is fed to the upper section of the $CO_2$ absorber and $CO_2$ is removed to the required specification. A much larger flow of "semi-lean" solution is fed to the lower section of the absorber to remove the bulk of the $CO_2$.

The Selexol stream from the bottom of this column, now rich in $CO_2$ is split into two streams. The majority of the flow is directed to a series of flash vessels operating at successively reducing pressure. The overhead vapour from the first vessel, which still contains considerable amounts of $H_2$, is recycled back to the inlet of the $H_2S$ absorber using the flash gas compressor. The overhead from the remainder of the flash vessels is sent to the $CO_2$ compressor. The Selexol, which is now semi-lean in $CO_2$, is cooled and pumped back to the lower section of the $CO_2$ absorber.

The remainder of the $CO_2$ rich Selexol stream from the bottom of the $CO_2$ absorber is cooled and pumped to the top of the $H_2S$ absorber where the sulphur compounds are absorbed. The Selexol from the bottom of the $H_2S$ absorber, now rich in $H_2S$ and containing about 25% of the inlet $CO_2$, is pumped to the $H_2S$ concentrator column which operates at a slightly higher pressure than the $H_2S$ absorber column via the rich / lean interchanger. The overhead from the $H_2S$ concentrator is recycled directly to the inlet of the $H_2S$ absorber. The liquor from the bottom of the $H_2S$ concentrator is flashed down to low pressure to remove the remainder of the $CO_2$. The overhead vapour, which contains some $H_2S$, is recycled back to the inlet of the $H_2S$ absorber using the flash gas compressor.

The Selexol is finally regenerated by steam stripping. The reboil duty for the stripper column is provided by hot process water from the gas treatment section. The overhead vapour from the stripper column, which contains 40% vol $H_2S$, is fed to the Claus unit where it is reacted with oxygen to form a solid sulphur product. The tail gas stream from the Claus reactor is compressed and recycled back to the inlet of the $H_2S$ absorber.

Selexol plants often use refrigeration. This is avoided in this design by having a higher solvent flowrate than would be necessary with a design using refrigeration. This increases the capital costs of the absorber and stripper columns themselves but overall costs of the Selexol unit is lower because a refrigeration package is not required.

**Gas Conditioning**
Sulphur and carbon dioxide free syngas from the top of the $CO_2$ absorber in the AGR unit is heated by exchange with hot demineralised water, and then expanded to the gas turbine fuel supply pressure, in an expander to generate power. Nitrogen from the ASU is added to dilute the hydrogen fuel gas stream as per GE's specifications, it is then superheated to 230°C against circulating demineralised water. A separate nitrogen stream is compressed, and superheated to 230°C again against circulating demineralised water before being fed directly to the gas turbine combustor. The combined effect of the two nitrogen streams is sufficient to control the $NO_x$ formation in the gas turbine to the required level.

**Sulphur Recovery**
The $H_2S$ is converted to pure sulphur in an oxygen blown Claus unit. The tail gas is compressed and recycled to the inlet of the $H_2S$ absorber removing any atmospheric sulphur emissions from the sulphur removal or recovery units. The sour water produced is pumped to the desaturator.

**Power Block**
The power block consists of a GE 6B gas turbine, modified for combustion of syngas, fitted with a modified HRSG. A new gas turbine is included to enable the steam from the gasification plant to be superheated without interfering with the existing HRSG. The steam produced in the capture plant of case 2 is superheated by the effluent gases from the ATR, and therefore no new gas turbine is required in that particular case. After superheating the steam passes to a condensing steam turbine. The exhaust from the steam turbine passes to a deaerator-condenser, which operates at a pressure of 40 mbar(a). The boiler feed water from the deaerator-condenser is pumped back to the gas treatment section.

The generators, transformers and switchgear for the power block are included in this section.

**$CO_2$ Compression and Drying**
The $CO_2$ removed in the acid gas removal unit is compressed to 22 bar(g), dried using a molecular sieve and compressed again to 110 bar(g) for export. The molecular sieve is regenerated using hot process water from the gas treatment section in a "no loss" configuration, which recycles the regeneration off gas back to the $CO_2$ compressor.

**Cooling Water**
Seawater, taken from a new intake, is circulated once through the major coolers and condensers and discharged directly back to the sea through a new discharge structure. A secondary fresh water system is used for smaller coolers and machinery.

**Water Treatment**
The feed water plant takes raw water and softens it to remove hard water anions. This is used as make-up water for the desaturator. A small stream is taken for the demin water plant.

The waste water plant takes black water from the quench blowdown and first filters it to remove soot, slag fines and other particulate matter. The filtered solids are recycled back to the coal grinding plant to recover the unconverted carbon. The filtered water is then treated by means of pH control, coagulation and flocculation, and finally ion exchange to meet the required specification. A small quantity of sludge is produced for disposal offsite.

### 5.5.2 Capture Plant Performance

*Table 5.17* shows the performance of the capture plant in case 3-1.

| **$CO_2$ Capture Plant Energy Balance** | | |
|---|---|---|
| Capture Plant Fuel Energy Input (LHV) | 2121.2 | MWth |
| Capture Plant Syngas Output (LHV + Heat) | 1405.3 | MWth |
| | | |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -244.9 | MWe |
| $CO_2$ Capture Plant Power Production | 190.1 | MWe |
| Capture Plant Net Power Output | -54.8 | MWe |
| | | |
| $CO_2$ Capture Efficiency | 85.8 | % |

***Table 5.17 - Case 3-1 Energy Balance Capture Plant***

Compared to the capture plant performances in case 2, it becomes clear that the coal reforming process is more energy intensive than the natural gas reforming process. The power consumption increased significantly (245 MWe compared to 159 MWe in case 2-1), which is mostly due to the power consumption of the larger $CO_2$ compressor and the Nitrogen compressor.
The power generation in case 3-1 is also increased. This can be explained by the fact that the power block consists of a complete combined cycle power plant, which produces a significant amount of electricity. A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The $CO_2$ capture efficiency is calculated by taking the actual $CO_2$ emission, compensate for the $CO_2$ in the inlet air to the gas turbine, and divide this by the maximum $CO_2$ emission from burning the original fuel (before reforming).

### 5.5.3 CCPP Description

The syngas, which is fed to the gas turbine combustion chamber, is a low-LHV fuel, and the gas turbine needs to be adjusted and controlled in the same way as with the previous pre combustion $CO_2$ capture cases.

The capture plant is located near the power plant plot and the syngas fuel is delivered at a temperature of 230 ºC. For this study the fuel is not preheated to a higher temperature, which could lead to higher efficiencies. This should be considered as an option for optimization.

### 5.5.4 CCPP Performance

The table shows the gas turbine data for case 2-2 in comparison to the reference case.

| Case | Reference Case | Case 3-1 |
|---|---|---|
| Fuel LHV | 46,855 kJ/kg | 6,416 kJ/kg |
| Fuel Flow / Temperature | 15.0 kg/s / 10 ºC | 103.7 kg/s / 230 ºC |
| Steam Injection Flow / Temperature | - | - |
| Air Inlet Flow | 618 kg/s | 523 kg/s |
| Combustor Exit Temperature | 1352 ºC | 1274.9 ºC |
| Exhaust flow / Temperature | 633 kg/s / 608 ºC | 627 kg/s / 565 ºC |
| Net Power Output | 258.8 MW | 286.1 MW |
| Net Electric Efficiency (LHV) | 36.8 % | 43.0 % |

***Table 5.18 - Case 3-1 Gas Turbine Performance***

*Table 5.19* shows the energy balance for the combined cycle power plant.

| Power Plant Energy Balance | | | | | |
|---|---|---|---|---|---|
| Gas Turbine Energy Input | | 1405.3 | MWth | | |
| | Fuel Consumption LHV | | | 1330.1 | MWth |
| | Fuel Sensible Heat Input (Tref. 15 ºC) | | | 75.2 | MWth |
| | Total Gas Turbine Energy Input | | | 1405.3 | MWth |
| Gas Turbine | | 581.4 | MW | | |
| | GT Gross power | | | 609.9 | MW |
| | GT losses | | | -28.6 | MW |
| | Net GT output | | | 581.4 | MW |
| Steam Turbine | | 248.0 | MW | | |
| | ST Shaft power | | | 250.5 | MW |
| | ST losses | | | -2.5 | MW |
| | Net ST output | | | 248.0 | MW |
| Generator losses | | -14.2 | MW | | |
| Balance of Plant losses | | -9.2 | MWe | | |
| | Boiler feed water pumps | | | -2.5 | MWe |
| | Cooling water pumps | | | -5.7 | MWe |
| | Condensate pumps | | | -0.2 | MWe |
| | Remaining losses (0.1%) | | | -0.8 | MWe |
| | BOP losses | | | -9.2 | MWe |
| Total Plant net power | | 806.0 | MWe | | |
| Net electrical efficiency | | 57.4 | % | | |

***Table 5.19 - Case 3-1 Power Plant Energy Balance***

### 5.5.5 Case 3-1 Overall Plant Balance

The overall energy balance for the combined $CO_2$ capture plant and power plant is shown in *Table 5.20*, which is composed of *Table 5.17* and *Table 5.19*.

| **Total Overall Plant Energy Balance** | | |
|---|---|---|
| Total Overall Plant Energy Input (LHV) | 2121.2 | MWth |
| | | |
| Combined Cycle Power Plant Net Electrical Output | 806.0 | MWe |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -244.9 | MWe |
| $CO_2$ Capture Plant Power Production | 190.1 | MWe |
| Total Overall Plant Net Power Output | 751.2 | MWe |
| | | |
| Net Overall Plant Electrical Efficiency | 35.4 | % |

***Table 5.20 - Case 3-1 Overall Plant Energy Balance***

The table shows that the overall plant net electrical efficiency decreased significantly compared to the reference case.

## 5.6 CASE 3-2: PRE COMBUSTION $CO_2$ CAPTURE BY REMOTE $H_2$ PRODUCTION FROM COAL

In case 3-2, capture is effected by removing the carbon from Coal before combustion with the capture plant located at 40 km distance from the power plant, see *Figure 5.5*. The Capture Plant converts the coal by partial oxidation (gasification) to synthesis gas (or syngas), which is a mixture of carbon monoxide and hydrogen. The carbon-free syngas is fed to the gas turbine.

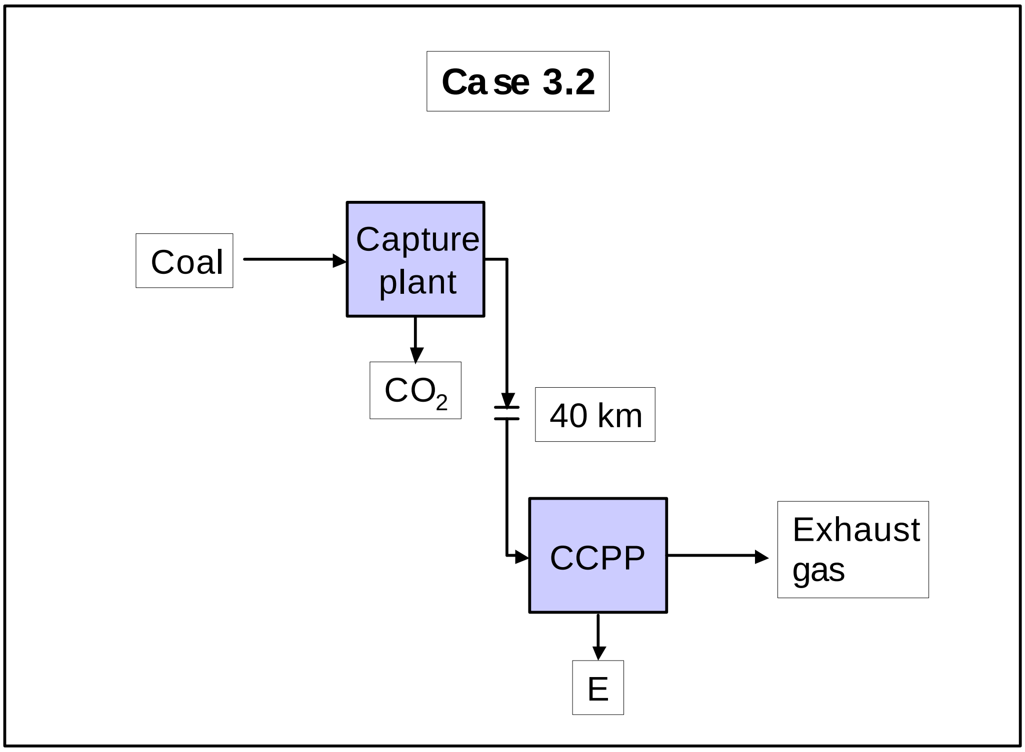



***Figure 5.5 - Case 3-2 Scheme***

### 5.6.1 Capture Plant Description

The Capture Plant converts a feed of coal to a fuel gas mixture of hydrogen and nitrogen suitable for refuelling a gas turbine. The plant consists of a gasification stage where a mixture of coal and water is partially oxidised with oxygen from an air separation unit (ASU). The synthesis gas, or syngas, which is a mixture of $H_2$, CO, $CO_2$ and $N_2$ produced in the gasification unit, is fed to a CO shift reactor, where the carbon monoxide and residual steam are converted to $H_2$ and $CO_2$. The $CO_2$ and $H_2S$ are removed from the shifted syngas, using a physical solvent, and dried. Nitrogen from the ASU is compressed and added, to the hydrogen rich fuel gas for $NO_x$ control. The $CO_2$ is regenerated from the solvent, dried and compressed for delivery to battery limits for subsequent disposal. An $H_2S$ rich gas stream is reacted with oxygen in a Claus unit to form a solid sulphur product.

The waste heat from the Capture Plant is used to generate steam, which is superheated in the HRSG's of two small gas turbines and generate electric power for internal use.

This section is to be read in conjunction with the process block diagram for case 3-2 and the mass balance for case 3-2 P03-3201.
Most of the process steps are equal to the process steps in case 2-1 and will not be repeated. The items that are different are described here.

**ASU**
Reference is made to paragraph 5.5.1.

**Coal Storage and Preparation**
Reference is made to paragraph 5.5.1.

**Gasification**
Reference is made to paragraph 5.5.1.

**CO Shift**
Reference is made to paragraph 5.5.1.

**Cooling and Condensation**
Reference is made to paragraph 5.5.1.

**Acid Gas Removal**
Reference is made to paragraph 5.5.1.

**Gas Conditioning**
Sulphur and carbon dioxide free syngas from the top of the $CO_2$ absorber in the AGR is dried and diluted with compressed nitrogen from the ASU. The fuel gas is then transferred to the remote combined cycle power plant.

**Sulphur Recovery**
Reference is made to paragraph 5.5.1.

**Power Block**
The power block consists of two GE 6B gas turbines, modified for combustion of syngas, fitted with HRSG's. The HP and LP steam from the gas treatment section is superheated in the HRSG's and passes to a condensing steam turbine. The exhaust from the steam turbine passes to a de-aerator condenser, which operates at a pressure of 40 mbar(a). The boiler feed water from the deaerator-condenser is pumped back to the gas treatment section.

The generators, transformers and switchgear for the power block are included in this section.

**$CO_2$ Compression and Drying**
Reference is made to paragraph 5.5.1.

**Cooling Water**
Seawater, from a new intake, is circulated once through major coolers and condensers and discharged directly back to the sea. A secondary fresh water system is used for smaller coolers and machinery.

**Water Treatment**
Reference is made to paragraph 5.5.1.

### 5.6.2 Capture Plant Performance

*Table 5.21* shows the performance of the capture plant in case 3-2.

| **CO2 Capture Plant Energy Balance** | | |
|---|---|---|
| Capture Plant Fuel Energy Input (LHV) | 2306.4 | MWth |
| Capture Plant Syngas Output (LHV + Heat) | 1344.3 | MWth |
| | | |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -269.1 | MWe |
| $CO_2$ Capture Plant Power Production | 269.4 | MWe |
| Capture Plant Net Power Output | 0.4 | MWe |
| | | |
| $CO_2$ Capture Efficiency | 85.5 | % |

***Table 5.21 - Case 3-2 Energy Balance Capture Plant***

Compared to the local case 3-1 a higher power production can be distinguished. A larger power plant is installed in the power block of the capture plant and this increases the electricity that is produced. A detailed breakdown of the power producers and consumers within the capture plant can be found in Appendix 5.

The $CO_2$ capture efficiency is calculated by taking the actual $CO_2$ emission, compensate for the $CO_2$ in the inlet air to the gas turbine, and divide this by the maximum $CO_2$ emission from burning the original fuel (before reforming).

### 5.6.3 CCPP Description

The fuel is delivered at the power plant at a low temperature of 21.5 ºC (compared to a temperature of 230 ºC in the local case 3-1). This is due to the 40 km transportation distance between the two sites.
In paragraph 5.3.3 it was stated that preheating the fuel is a feasible option to increase the overall efficiency of the power plant. In this case the fuel is preheated by heat exchangers, which are fed with steam generated by the HRSG's in the power plant.

When fuel preheating is applied, steam injection is needed to limit the $NO_x$ emissions below the permitted limit.
In this study the fuel is preheated until the temperature of the mixture of fuel and steam is about 230 ºC. At this temperature no extra measures need to be taken to materials in the existing equipment. The temperature level can be subject to optimization, as this is not considered in this study.

### 5.6.4 CCPP Performance

The table shows the gas turbine data for case 3-2 in comparison to the reference case.

| Case | Reference Case | Case 3-2 |
|---|---|---|
| Fuel LHV | 46,855 kJ/kg | 7,480 kJ/kg |
| Fuel Flow / Temperature | 15.0 kg/s / 10 ºC | 89.7 kg/s / 223 ºC |
| Steam Injection Flow / Temperature | - | 5.9 kg/s / 340.6 ºC |
| Air Inlet Flow | 618 kg/s | 532 kg/s |
| Combustor Exit Temperature | 1352 ºC | 1274.9 ºC |
| Exhaust flow / Temperature | 633 kg/s / 608 ºC | 627 kg/s / 567 ºC |
| Net Power Output | 258.8 MW | 286.0 MW |
| Net Electric Efficiency (LHV) | 36.8 % | 42.6 % |

***Table 5.22 - Case 3.2 Gas Turbine Performance***

*Table 5.23* shows the energy balance for the complete combined cycle power plant.

| Power Plant Energy Balance | | | | | |
|---|---|---|---|---|---|
| Gas Turbine Energy Input | | 1344.3 | MWth | | |
| | Fuel Consumption LHV | | | 1341.4 | MWth |
| | Fuel Sensible Heat Input (Tref. 15 ºC) | | | 3.0 | MWth |
| | Total Gas Turbine Energy Input | | | 1344.3 | MWth |
| Gas Turbine | | 581.1 | MW | | |
| | GT Gross power | | | 609.7 | MW |
| | GT losses | | | -28.6 | MW |
| | Net GT output | | | 581.1 | MW |
| Steam Turbine | | 215.0 | MW | | |
| | ST Shaft power | | | 217.1 | MW |
| | ST losses | | | -2.2 | MW |
| | Net ST output | | | 215.0 | MW |
| Generator losses | | -13.5 | MW | | |
| Balance of Plant losses | | -8.3 | MWe | | |
| | Boiler feed water pumps | | | -2.4 | MWe |
| | Cooling water pumps | | | -5.0 | MWe |
| | Condensate pumps | | | -0.2 | MWe |
| | Remaining losses (0.1%) | | | -0.8 | MWe |
| | BOP losses | | | -8.3 | MWe |
| Total Plant net power | | 774.3 | MWe | | |
| Net electrical efficiency | | 57.6 | % | | |

***Table 5.23 - Case 3-2 Power Plant Energy Balance***

The amount of heat added to the fuel by preheating is equal to 63.5 MWth.

### 5.6.5 Overall Plant Balance

*Table 5.24* shows the overall energy balance for the combined $CO_2$ capture plant and CCPP. It is composed from *Table 5.21* and *Table 5.23*.

| **Total Overall Plant Energy Balance** | | |
|---|---|---|
| Total Overall Plant Energy Input (LHV) | 2306.4 | MWth |
| | | |
| Combined Cycle Power Plant Net Electrical Output | 774.3 | MWe |
| $CO_2$ Capture Plant Auxiliary Power Consumption | -269.1 | MWe |
| $CO_2$ Capture Plant Power Production | 269.4 | MWe |
| Total Overall Plant Net Power Output | 774.6 | MWe |
| | | |
| Net Overall Plant Electrical Efficiency | 33.6 | % |

***Table 5.24 - Case 3-2 Overall Plant Energy Balance***

## 5.7 OVERALL RESULTS AND CONCLUSIONS

The performance results for the different cases are described in the following table for comparison.

| **Total Overall Plant Energy Balance** | Ref. | 1 | 2-1 | 2-2 | 3-1 | 3-2 | |
|---|---|---|---|---|---|---|---|
| Total Overall Plant Energy Input (LHV) | 1404.6 | 1404.6 | 1672.4 | 1671.0 | 2121.2 | 2306.4 | MWth |
| | | | | | | | |
| Combined Cycle Power Plant Net Electrical Output | 784.8 | 664.3 | 809.6 | 764.3 | 806.0 | 774.3 | MWe |
| $CO_2$ Capture Plant Auxiliary Power Consumption | 0.0 | -38.5 | -158.9 | -168.0 | -244.9 | -269.1 | MWe |
| $CO_2$ Capture Plant Power Production | 0.0 | 0.0 | 43.0 | 71.1 | 190.1 | 269.4 | MWe |
| Total Overall Plant Net Power Output | 784.8 | 625.9 | 693.7 | 667.4 | 751.2 | 774.6 | MWe |
| | | | | | | | |
| Net Overall Plant Electrical Efficiency | 55.9 | 44.6 | 41.5 | 39.9 | 35.4 | 33.6 | % |

***Table 5.25 - Comparison Overall Plant Energy Balances***

*Table 5.25* shows clearly that $CO_2$ Capture has significant impact on the power plant electrical efficiency. This is due to the high power consumption of the capture plant. The reference plant without $CO_2$ capture reaches an efficiency of 55.9% and in the case of pre combustion $CO_2$ capture by syngas production from coal (case 3-2), this efficiency decreased with more then 20%-points to 33.6%.
The post combustion $CO_2$ capture case has the best electrical efficiency compared to the $CO_2$ capture cases.
The table also shows that the CCPP electrical output is about 32 to 35 MWe lower in the remote cases in comparison to the local cases. This is caused by the steam bleed, which is needed for the preheating of the fuel in the remote cases. As this steam is used for the fuel preheating, it is no longer available for expansion in the steam turbine. This effect is partially compensated by the higher power production in the $CO_2$ Capture Plant. In the local cases the fuel is preheated in the capture plant, and in the remote cases the fuel is preheated with steam from the CCPP. Therefore in the remote case the capture plant has more steam available for power production. The

overall difference in efficiency between a local and its remote case (transport loss) is between 1.6 and 1.8%-points.

Because the different fuels have different $CO_2$ emissions and the different cases have different power generation efficiencies, it is interesting to look at the $CO_2$ emission per kWh electricity produced for each case. By adding a price tag to avoided $CO_2$ production, the premium on the electricity price can be calculated for the $CO_2$ capture power plant.

| **$CO_2$ emission per kWh electricity** | **Ref.** | **1** | **2-1** | **2-2** | **3-1** | **3-2** | |
|---|---|---|---|---|---|---|---|
| Total Overall Plant Net Power Output | 784.8 | 625.9 | 693.7 | 667.4 | 751.2 | 774.6 | MWe |
| $CO_2$ emission in kg/s | 81.4 | 11.7 | 13.9 | 13.9 | 27.1 | 30.2 | kg/s |
| | | | | | | | |
| **$CO_2$ emission per kWh** | **373.3** | **67.0** | **72.3** | **74.8** | **129.9** | **140.1** | **g CO2/kWh** |

***Table 5.26 - $CO_2$ emission per kWh generated electricity***

*Table 5.26* shows an important conclusion, which should be taken into account when $CO_2$ capture rates are discussed. The $CO_2$ capture rate for all cases is at least 85%, when based on the amount of $CO_2$, which is avoided on a per kg fuel basis.
However the $CO_2$ captured per kWh electricity produced is much lower. This is due to the decreased electrical efficiency of the CCPP with $CO_2$ capture, which implies that the specific fuel consumption per kWh electricity has increased. For the overall plant performance this is a more appropriate figure to compare cases, as it takes the additional energy consumption of the capture plant into account.

*Table 5.27* results from *Table 5.26* and shows the relative $CO_2$ emissions per kWh net electricity production compared to no $CO_2$ capture from the natural gas fired CCPP from the reference case.

| **$CO_2$ Capture** | **Ref.** | **1** | **2-1** | **2-2** | **3-1** | **3-2** | |
|---|---|---|---|---|---|---|---|
| **Relative $CO_2$ emission** | 100.0 | 17.9 | 19.4 | 20.0 | 34.8 | 37.5 | % |
| **Relative $CO_2$ Capture efficiency** | 0.0 | 82.1 | 80.6 | 80.0 | 65.2 | 62.5 | % |

***Table 5.27 - $CO_2$ Capture***

It is clear to see that the coal based pre combustion cases perform less efficiently compared to the gas based pre combustion cases. The efficiency of the local cases is better then the remote cases, which is expected, as the remote cases demand a high amount of compression power to transport the fuel gas over the 40 km distance and does not allow waste heat utilisation for fuel preheating in the pre combustion plant.
Case 1, which is the post combustion case, has the best performance with respect to total electrical efficiency as well as $CO_2$ Capture efficiency per kWh electricity produced.

# 6. CAPITAL EXPENDITURE

## 6.1 INTRODUCTION

To evaluate the economic feasibility of retrofitting a standard natural gas fired power plant with post- or pre-combustion $CO_2$ capture it is required to have an overview of the capital and operational expenditures for all alternatives considered.
The capital cost figures of the 2 * 400 $MW_e$ power plant and the post- and pre-combustion $CO_2$ capture plants have been based on the following general starting points:

- The processes to be assessed will be state-of-the art for construction in the year 2004.
- The plants will be assumed to be on the NE coast of the Netherlands, within 1 km of the sea (i.e. availability of seawater for cooling purposes and ship unloading facilities).
- A green field site with no special civil work implications will be assumed
- The plants will be built on a turnkey basis and are provided with all required (auxiliary) systems. The power plant and the capture plants both have dedicated auxiliary systems (i.e. minimum integration). Facilities and infrastructure required outside the plant limits, e.g. HV connection, fuel supply, transport and storage of $CO_2$, etc. are not included in the cost estimate.
- The CCPP and the capture plant will not be realized simultaneously. In case of a local capture plant it is assumed the new plant is located next to the existing power plant. In case of a remote capture plant a distance of 40 km between both sites is considered. The high pressure fuel gas line from the fuel plant to the power plant will be routed underground. The pipeline is assumed to be through agricultural land, with no passage through urban areas.
- All cost figures are presented in USD (exchange rate used: EUR/USD = 1.23).

Besides the general starting points also the following specific cost estimating approach will be applicable:

**CCPP**
The capital cost for the power plant will be based on actual cost figures from plants recently taken into operation and/or under construction. All costs with respect to the power plant will be presented as one total cost figure.

**Capture Plant**
The capital cost for the capture plant will be based on actual cost figures for the individual equipment with an installation factor per equipment. The individual equipment costs have been obtained by price calculation of the equipment based on the actual design information and price comparison with prices available of similar equipment, obtained from vendor data. The installation factors, used for cost estimating, are based on the experience of Jacobs with similar units/processes. All costs with respect to the capture plant are presented for the following main plant sections:

Case 1 Post combustion CO2 capture

- Acid Gas Removal
- $CO_2$ Compression and drying
- Offsites and Utilities

Case 2.1 Pre combustion $CO_2$ capture by local $H_2$ production from natural gas

- Air Compression
- Reforming and HT Cooling
- Shift and LT Cooling
- Acid Gas Removal
- $CO_2$ Compression and drying
- Power Generation
- Offsites and Utilities

Case 2.2 Pre combustion $CO_2$ capture by remote $H_2$ production from natural gas

- Reference is made to case 2.1

Case 3.1 Pre combustion $CO_2$ capture by local $H_2$ production from coal

- Air Separation Unit
- Coal Receiving, grinding and slurry preparation
- Gasification unit
- Gas Treatment Package
- Acid Gas removal
- Product Gas Exports
- Power Generation (combined cycle unit)
- Offsites and Utilities

Case 3.2 Pre combustion $CO_2$ capture by remote $H_2$ production from coal

- Reference is made to case 3.1

Reference is made to appendix 4 for a summary list of the equipment (no design details) concerned per case.

Per plant section the split up for the following cost items is presented:

- Direct materials
- Construction
- Engineering and construction services

The individual cost for all individual systems/activities such as individual equipment, auxiliary systems, civil, electrical, instrumentation, etc. will not be presented. To present an accurate cost overview for all individual systems/activities a great effort is required as this is only possible with a detailed break down per system/activity. As a (detailed) break down will not contribute to the aim of this study the above mentioned estimating approach has been followed.

The overall accuracy of the overall cost estimates is in the range of ±25%.

For determining the overall project cost the following additional charges are applicable:

- A cost of 7% of the installed plant cost (overnight construction) will be assumed to cover the owners cost (i.e. process/patent fees, fees for agents or consultants, legal and planning costs land purchase, surveys, general site preparation, etc.)
- A cost of 10% of the installed plant cost (overnight construction) will be assumed to cover project contingency.

## 6.2 CAPITAL EXPENDITURE

A summary of the capital expenditure (excluding interest during construction) and specific costs in USD per kWe of installed capacity for the reference power plant and the capture plants are presented in *Table 6.1* and *Table 6.2*.

| **Capital Expenditures** | | | **Reference CCPP** |
|---|---|---|---|
| Overnight construction costs | | M USD | 354.7 |
| Owners cost | 7% | M USD | 24.8 |
| Contingency | 10% | M USD | 35.5 |
| Total installed cost | | M USD | 415.0 |
| Specific investment | | USD/kWe | 529 |

***Table 6.1 - Capital Expenditure Reference case***

| | | | **Case** | | | | |
|---|---|---|---|---|---|---|---|
| **Additional Capital Expenditures** | | | **1** | **2-1** | **2-2** | **3-1** | **3-2** |
| Overnight construction costs | | M USD | 337.7 | 486.4 | 641.2 | 822.4 | 1,020.7 |
| Owners cost | 7% | M USD | 23.6 | 34.0 | 44.9 | 57.6 | 71.4 |
| Contingency | 10% | M USD | 33.8 | 48.6 | 64.1 | 82.2 | 102.1 |
| Total additional installed cost | | M USD | 395.1 | 569.1 | 750.3 | 962.2 | 1,194.2 |
| Specific additional investment | | USD/kWe | 631 | 820 | 1,124 | 1,281 | 1,542 |

***Table 6.2 - Additional Capital Expenditures Capture plants***

Reference is made to appendix 6 for the split up of the capital cost estimate of the various cases.

# 7. ECONOMIC ANALYSIS

## 7.1 INTRODUCTION

An economic analysis will be executed to evaluate the economic performance of the $CO_2$ capture retrofitted combined cycle power plants against the reference power plant. The economic calculations will be based on the starting points as provided by IEA GHG.

The results will be expressed in power production cost and $CO_2$ emission avoidance cost.

Both values will be calculated for a Net Present Value (NPV) of zero (0) for the complete project 25 years after the initial start-up of the CCPP.

## 7.2 CASH FLOW CALCULATIONS

### 7.2.1 Background

Using cash flow calculations one can determine the real cost of electricity production and $CO_2$ avoidance. This paragraph shows the calculation method and the criteria used. As a result the cost of $CO_2$ avoidance for the different plant configurations is summarised. The cash flow calculations are executed with the IEA GHG economic assessment model applicable for assessment of levelled costs of generation in new power plants. As the original model is not suitable for the assessment of retrofits the spreadsheet has been modified in order to evaluate retrofitting.

The cash flow calculation shows the cash flows of a power plant throughout its lifetime and calculates the net present value of these cash flows. The net present value (NPV) is the value of a project today if all future cash flows (including investments) are discounted to today's value using a discount ratio.

The cash flows include the following items:

- Revenues
- Fossil Fuel costs
- Maintenance costs
- Labour costs
- Chemicals and consumables costs
- Insurance
- Capital expenditures
- Working capital
- De-commissioning costs

The cash flow is calculated for 2 years of construction of the reference natural gas fired CCPP followed by 25 years of operation. The production costs per kWh of electricity are calculated by setting the NPV of the power plant to zero. This can be

achieved by varying the kWh price until the revenues balance the costs over the whole lifetime of the power plant.
The calculated kWh price at which the NPV of the reference case is zero, is maintained for the calculations to the different cases. The $CO_2$ avoidance cost are varied until the NPV of each of the cases is zero.

For the retrofit cases it is assumed that the new capture plants are constructed while the CCPP is still in operation. The CCPP will only be taken out of operation to allow for making the required tie-ins with the new plant and realize the required internal modifications (e.g. replace gas turbine combustion system). The 25 years of operation evaluation criteria for the CCPP will not change. There is no residual value at the end of the lifetime of the CCPP.

Sensitivity analyses will be made to evaluate the economic performance of the various options when varying one parameter at the time.
Parameters to be varied are:
- Fuel price (-50%/+100%)
- Discount rate (5%)
- Year of retrofit (-5/+5 year)

### 7.2.2 Starting points

The yearly cash flow is calculated using the IEA GHG criteria.

Criteria that need further explanation are discussed below:

<u>Discount rate and cost of capital</u>
All cash flows will be discounted using a discount rate of 10%. These cash flows also include the debts made during the design, construction and commissioning.

<u>Year of retrofit</u>
The retrofitted CCPP will be commissioned/started-up 10 years after the initial start-up of the CCPP. Design and construction period of the capture plant starts 2 (natural gas fuelled plant) or 3 (coal fuelled plant) years earlier.

<u>Escalation</u>
In accordance with the IEA GHG criteria, no escalation has been included.

<u>Commissioning</u>
A 3-month commissioning period will be allowed for all types of plant. In effect this means that during the first year the load factor of the plant is reduced by 25%. The reference power plant will operate at a load factor of 90% during the first year; by adding a commissioning period of 3 months, the load factor will be reduced to 67.5%. When the retrofitted plant is started up the identical approach is applicable for natural gas fuelled plants. However for the coal fuelled plants a load factor of 60 % is applicable for the first year, which has to be corrected for the 3-month commissioning period, resulting in a load factor of 45%.

Load Factor
The natural gas fuelled power plant(s) will operate at a load factor of 90% during a normal year. The coal-fuelled power plant(s) will operate at a load factor of 85% during a normal year. The load factor affects the electricity production, consumption of all consumables, disposal of wastes and maintenance costs. It does not reduce the labour costs and insurance.

De-commissioning
The costs associated with shut down of the plant can be taken as a percentage of the capital investment. However, since these costs occur only once at the end of the lifetime of the (power) plant the discounted cash flow is reduced to a minimum. As a result the de-commissioning costs only comprise 0.1 to 0.2% of the kWh price and are insignificant and therefore neglected.

Maintenance
The Maintenance expenditures are 2% p.a. of the installed costs for the CCCP and the gas conversion and treatment plants. For “coal handling” plants, maintenance expenditures of 4% p.a. of the installed plant costs are used.

Contingencies
An allowance is made for estimating error and process unknowns / development. This allowance is set as a percentage of the overnight construction cost. A contingency factor of 10% covers most of the risks.

Labour
The labour cost for one operator is set to 75.000 USD/year. A percentage is added to the labour cost for indirect costs for supervision (20%) and administration + overhead (30%). The number of operators (5 shift) necessary for each plant is assumed to be:

- Ten (10) operators for the NG fired CC reference power plant
- Fifteen (15) operators, power plant operators included, for the post-combustion $CO_2$ capture option
- Twenty (20) operators, power plant operators included, for the local natural gas fuelled pre-combustion $CO_2$ capture options
- Twenty (20) operators, power plant operators excluded for the remote natural gas fuelled pre-combustion $CO_2$ capture options
- Twenty five (25) operators, power plant operators included, for the local coal fuelled pre-combustion $CO_2$ capture options
- Thirty (30) operators, power plant operators excluded for the remote coal fuelled pre-combustion $CO_2$ capture options

Consumables and Working Capital
The consumables consist of the following components:
- Chemicals for boiler water treatment
- Chemicals for waste water treatment
- Lubricants
- Potable water

- M(D)EA solution + additives
- Catalyst + internals
- Solexol solvent

Working capital for storage of consumables is assumed to be 30 days.

Fuel Price
The fuel price is set at 3.0 USD/GJ (LHV) for natural gas and 1.5 USD/GJ (LHV) for coal.

Waste Disposal
For hazardous waste disposal the following costs are used:
- Small quantities 250 €/ton
- Large quantities 150 €/ton

It is assumed that the gasifier slag produced in the coal cases is a product, which can be sold. For the economical analysis it is assumed that the profits equal the disposal costs.

## 7.3 RESULTS

The results from the cash flow calculations are presented in *Table 7.2*. Reference is made to appendix 7 to the detailed calculation results. The results are given for the reference natural gas fired CCPP and the various $CO_2$ capture retrofitted cases. *Table 7.1* shows the specific investments and electric efficiencies.

The total specific investment is defined as the overall investment of CCCP and fuel/$CO_2$ capture plant without inflation correction, divided by the net power output after the retrofit. The overall electric efficiency presented for the fuel/$CO_2$ capture plants is also applicable for the retrofitted situation. Up to the retrofit the overall electric efficiency of the reference CCCP is applicable.

| | | **Total Specific Investment** | **Overall Electric Efficiency** |
|---|---|---|---|
| | | **USD/kWe** | **%** |
| **CCPP** | Reference power plant | 529 | 55.9 |
| **Case 1** | | 1294 | 44.6 |
| **Case 2.1** | | 1419 | 41.5 |
| **Case 2.2** | | 1746 | 39.9 |
| **Case 3.1** | | 1833 | 35.4 |
| **Case 3.2** | | 2077 | 33.6 |

***Table 7.1 – Investments and Efficiencies***

## 7.4 CALCULATION OF $CO_2$ COST

Costs per ton of avoided $CO_2$ resulting from decarbonisation are calculated by varying the $CO_2$ avoidance costs until the NPV of the case is zero, at an electricity price equal to the price at which the NPV of the reference power plant is zero.

Electricity production costs are calculated as described in section 7.2.1. Specific $CO_2$ emission is calculated by dividing the emitted amount of $CO_2$ per year accountable to the fuel (i.e. absolute $CO_2$ emission is corrected for the $CO_2$ in the combustion air) by the yearly net power production. Both figures assume 8760 yearly hours and the applicable load factor. The $CO_2$ emission avoidance cost is defined to be the value at which the NPV of the considered option is zero.

| | Electricity Production Cost | Specific avoided $CO_2$ | Cost of avoided $CO_2$ |
|---|---|---|---|
| | USD/MWh | Ton $CO_2$/MWh | USD/Ton $CO_2$ |
| **CCPP** | **29.97** | | |
| **Case 1** | 29.97 | 0.306 | 73.24 |
| **Case 2.1** | 29.97 | 0.301 | 95.05 |
| **Case 2.2** | 29.97 | 0.299 | 124.33 |
| **Case 3.1** | 29.97 | 0.243 | 131.36 |
| **Case 3.2** | 29.97 | 0.233 | 168.13 |

***Table 7.2 - $CO_2$ Emission Avoidance Cost***

## 7.5 RESULTS SENSITIVITY ANALYSIS

The following parameters were altered in order to perform a sensitivity analysis:
A. Fuel price – increase of 100%
B. Fuel price – decrease of 50%
C. Discount rate – decreased from 10% to 5%
D. Year of retrofit – (5 years after start-up of CCPP in stead of 10 years)
E. Year of retrofit – (15 years after start-up of CCPP in stead of 10 years)

Electricity production costs and costs of avoided $CO_2$ have been recalculated for all cases. The electricity production costs for the reference plant are recalculated using an altered fuel price or discount rate in the sensitivity analyses A, B and C.
These recalculated electricity production costs for the reference cases are kept constant for the corresponding cases and the $CO_2$ avoidance costs are calculated by finding the appropriate value at which the NPV is zero for each separate case.

### 7.5.1 Fuel price sensitivity

The influence of fuel price levels on electricity production cost and cost of avoided $CO_2$ is shown in *Table 7.3* and *Table 7.4*. An increased price level of fuel results in increased electricity production cost, having a negative impact on the cost of avoided $CO_2$ production for 1 and 2 and a positive impact on case 3. The specific difference in fuel costs between natural gas and coal increases, which is beneficial for coal firing compared to natural gas firing.
The opposite is true for a fuel price *decrement*.

| Sensitivity calculation Fuel Price +100% | Electricity production cost | Cost of avoided CO2 | Change of avoided Cost of CO2 |
|---|---|---|---|
| | USD/MWh | USD/Ton CO2 | % |
| **CCPP Ref.** | 49.31 | | |
| **Case 1** | 76.65 | 89.27 | 21.9 |
| **Case 2.1** | 84.63 | 117.33 | 23.4 |
| **Case 2.2** | 94.14 | 150.17 | 20.8 |
| **Case 3.1** | 77.38 | 115.29 | -12.2 |
| **Case 3.2** | 85.44 | 154.95 | -7.8 |

***Table 7.3 - Sensitivity analysis results A***

| Sensitivity calculation Fuel Price -50% | Electricity production cost | Cost of avoided CO2 | Change of avoided Cost of CO2 |
|---|---|---|---|
| | USD/MWh | USD/Ton CO2 | % |
| **CCPP Ref.** | 20.31 | | |
| **Case 1** | 40.30 | 65.23 | -10.9 |
| **Case 2.1** | 45.57 | 83.91 | -11.7 |
| **Case 2.2** | 53.56 | 111.42 | -10.4 |
| **Case 3.1** | 54.24 | 139.40 | 6.1 |
| **Case 3.2** | 61.07 | 174.72 | 3.9 |

***Table 7.4 - Sensitivity analysis results B***

### 7.5.2 Discount rate sensitivity

The influence of the discount rate on electricity production cost and cost of avoided $CO_2$ is shown in *Table 7.5*. As expected, lowering the discount rate has a positive impact on the electricity production cost as well as the costs of avoided $CO_2$ for all cases studied.

| Sensitivity calculation Discount rate 5% (instead of 10%) | Electricity production cost | Cost of avoided CO2 | Change of avoided Cost of CO2 |
|---|---|---|---|
| | USD/MWh | USD/Ton CO2 | % |
| **CCPP Ref.** | 27.03 | | |
| **Case 1** | 45.23 | 59.43 | -18.9 |
| **Case 2.1** | 50.82 | 79.02 | -16.9 |
| **Case 2.2** | 51.93 | 102.47 | -17.6 |
| **Case 3.1** | 50.22 | 95.27 | -27.5 |
| **Case 3.2** | 55.92 | 123.88 | -26.3 |

***Table 7.5 - Sensitivity analysis results C***

### 7.5.3 Retrofit year sensitivity

The influence of the moment of retrofit on electricity production cost and cost of avoided $CO_2$ is shown in *Table 7.6* and *Table 7.7*. Earlier retrofit results in reduced costs of avoided $CO_2$ because more $CO_2$ is captured over the lifetime of the plant. The more years the power plant is operated in "capture mode" the more money it makes compared to the reference cases, which are retrofitted 10 years after startup. A five year earlier retrofit lowers cost of avoided $CO_2$ per ton with 6% to 10%, whereas a "delay" in retrofit increases the cost of avoided CO2 per ton with 13% to 22%.

| Sensitivity calculation Retrofit year - 5 (5 years from start up) | Electricity production cost | Cost of avoided CO2 | Change of avoided Cost of CO2 |
|---|---|---|---|
| | USD/MWh | USD/Ton CO2 | % |
| **CCPP Ref.** | 29.97 | | |
| **Case 1** | 51.11 | 69.02 | -5.8 |
| **Case 2.1** | 56.92 | 89.53 | -5.8 |
| **Case 2.2** | 64.82 | 116.76 | -6.1 |
| **Case 3.1** | 58.90 | 118.92 | -9.5 |
| **Case 3.2** | 65.54 | 152.58 | -9.3 |

***Table 7.6 - Sensitivity analysis results D***

| Sensitivity calculation Retrofit year + 5 (15 years from start up) | Electricity production cost | Cost of avoided CO2 | Change of avoided Cost of CO2 |
|---|---|---|---|
| | USD/MWh | USD/Ton CO2 | % |
| **CCPP Ref.** | 29.97 | | |
| **Case 1** | 55.32 | 82.77 | 13.0 |
| **Case 2.1** | 62.34 | 107.49 | 13.1 |
| **Case 2.2** | 72.18 | 141.42 | 13.7 |
| **Case 3.1** | 68.82 | 159.71 | 21.6 |
| **Case 3.2** | 77.43 | 203.56 | 21.1 |

***Table 7.7 - Sensitivity analysis results E***

# 8. RETROFITTING ISSUES

When a standard combined cycle power plant is retrofitted to a low $CO_2$ emission power plant, modifications to the installation are needed or new add-on installations are required. These modifications are often not foreseen at the design phase of the original power plant, and this can therefore create barriers to the retrofit, either technical or economical. This chapter identifies the possible barriers and describes how action taken during the design phase of a new power plant can be used to minimize barriers to a future retrofit and even optimize the overall plant configuration by allowing future integration of capture plant and power plant.

## 8.1 BARRIERS TO RETROFIT

In general a standard combined cycle power plant is not designed for the future possibility of major modifications due to retrofitting the plant. Especially for modern power plants, standardization and modularization are getting more and more important as manufacturers are trying to find ways to cut engineering and erection costs. This however also complicates a retrofit, as there is not much space left for expansion or adjustments to the installation. Furthermore current plants are optimized based on the original design parameters and a change to the process parameters or plant design often leads to a sub optimal design, which may not survive in a competitive market environment.

This paragraph aims to identify possible barriers to retrofitting existing combined cycle power plants to a power plant with $CO_2$ capture. The barriers are listed below:

**Plot Space**

A fuel processing plant as well a post combustion $CO_2$ capture unit (flue gas scrubber) requires a considerable amount of plot space. This plot space needs to be available in the near surroundings of the plot. When the plant is situated in a residential area or a heavily industrialised area this plot space is not always available.

Especially for a post combustion unit with large atmospheric flue gas flows, the capture unit needs to be installed literally next to the CCCP. It is not desirable to transport these large quantities of flue gas over even a short distance. From a technical point of view the resulting higher pressure loss will to a great extent affect the performance. From an economical point of view the costs for this large diameter piping are high.

In case of a fuel processing plant, the distance between the CCPP and fuel plant is less critical from a technical point of view. However, the longer the distance is, the higher the costs are for connecting the plants. Furthermore it shall be clear that the area classification for the fuel plant is an important issue in the plot location. Of course these remarks are a less critical issue in the remote cases, at which the choice for the location of the fuel plant is “open”.

Also significant plot space is required for construction. This is an important item with respect to the overall construction cost and time schedule. With little construction space available, items need to be delivered as prefab installations as much as possible (no place to construct on-site) and planning of the activities becomes very important (no place to store materials/equipment).

**Available Space within installation**
The existing installation is designed to take up the least plot space as possible. When tie-ins are required, problems can arise with the available place within the installation itself.
For example, in the pre combustion case the fuel supply piping has to be replaced as fuel flows increase significantly. In the post combustion case additional LP steam piping of approximately 36 inch is needed for steam supply from the power plant to the capture plant.
Fitting the large diameter piping in the existing CCPP will create difficulties, as the installation is not designed for this extra piping. Depending on the actual situation, a certain amount of effort will be needed to enable the tie-inns and because of this costs will rise.

**Accessibility**
The delivery of large equipment can be a problem when the power plant is situated in an industrial surrounding. This is the case at both the post combustion as well as the pre combustion cases (except for the remote options). It might be necessary to deliver very large equipment blocks in parts and build the equipment on-site. This can influence the cost of retrofitting negatively and have great influence on the time schedule.
To illustrate this, the largest new equipment items for the different options are listed here:

- Case 1 — $CO_2$ absorber: 9.7 m. diameter by 20 m. tan-tan
- Case 2-1 — $CO_2$ absorber: 6.5 m. diameter by 39 m. tan-tan
- Case 2-2 — $CO_2$ absorber: 6.5 m. diameter by 39 m. tan-tan
- Case 3-1 — $CO_2$ absorber: 6.4 m. diameter by 31 m. tan-tan
  ASU main column: 5.3 m. diameter by 50 m. tan-tan
- Case 3-2 — $CO_2$ absorber: 6.5 m. diameter by 31 m. tan-tan
  ASU main column: 5.5 m. diameter by 50 m. tan-tan

**Changed process conditions**
The gas turbine performance will differ significantly when fired on a low-LHV fuel, which is the case with pre combustion $CO_2$ capture. The standard power plant has been designed for firing on natural gas, and the changed gas turbine performance will lead to different process conditions in the installation. This can lead to technical problems that can be hard to overcome.

For instance the lower exhaust temperature of the gas turbine exhaust gas will lead to a lower steam temperature at the HP superheater outlet. This can create problems in the condensing section of the steam turbine, causing too high moisture content in the steam, which damages the last blade rows in the steam turbine condensing section.
For the post combustion case the added flue gas scrubber introduces an additional pressure loss at the flue gas side. Additional measures have to be taken to overcome and/or reduce this pressure loss. This kind of problems may even lead to the complete replacement of parts of the existing equipment, with equipment that is designed for the new process conditions.

Whether this kind of problems will occur, depends on the design of the installation. As no design is exactly the same, it will be necessary to determine possible problems for each installation that is retrofitted. This applies not only to base load operation, but also to different part load situations, at several ambient conditions.

**Demin Water Capacity**

Injection of high quality steam is needed in case gas turbine DLN burners are replaced with conventional burners. Hence demin water plant capacity is to be enlarged for steam injection.

In case of a local CCPP and remote capture plant an additional demin water plant is needed, which requires extra plot space.

The demin water consumption for each case can be found in Appendix 5. These consumptions represent the water consumptions in normal operation. When the CCPP is fired on secondary fuel (i.e. natural gas), higher demin water consumption is applicable for all cases, as steam injection is needed to restrict $NO_x$ emissions.

**Cooling Water Capacity**

The fuel processing plant will increase the cooling water demand and cooling water duty significantly. The CCPP cooling system will probably not be sufficient to meet this increase in demand and therefore a new system might be necessary. It will not be a problem to install new piping and cooling water pumps, as these are simply add-on installations. When the spare capacity of the cooling water intake and outlet is too low, the implications are greater. Increasing the capacity demands for extensive civil works and sufficient space may not be available for these expansions. In that case cooling tower systems may be required.

**Operational flexibility**

Inlet Guide Vane control is used to operate the gas turbine when fired on low-LHV fuels. These IGV's are normally used to enable more efficient part load operation of the CCPP. Using them at full load means that the part load efficiency will be affected in a negative way, as this control can no longer be used in its full extent for part load operation.

CCPP units are generally spoken very flexible with respect to the time required for start up and shut down. In the pre combustion case, a complete fuel plant is added, which complicates start up and shut down as this plant has to start/stop as well.

**Permitting**

In practice it is time consuming and expensive to get the needed permits for expansions or modifications to an installation. Retrofitting an existing CCPP means that the emissions to air and water change, the noise level can increase, more cooling duty is required, etcetera. This will probably lead to the need for new or adjusted permits. The time and effort, which is consumed when new permits are needed, should not be underestimated. This will especially apply to high-pressure fuel lines near urban areas.

**Fuel storage and transport**

In case of coal fired plants a large open space is needed for coal storage. Because the coal in store is subject to self-ignition, hence the storage spreads smoke and smell, it is preferred to keep the plant away from residential area's and safe zones.

High pressure fuel lines are needed to transport syngas in the case a Fuel/$CO_2$ capture plant is built remotely from the existing CCPP. Routing of the HP fuel lines is complex because off the line size of 30-36 inch and the probable interference with road crossings and areas with explosion safety demands, which do not allow an HP fuel line to cross.

## 8.2 DESIGN FOR FUTURE RETROFIT

In the previous paragraph the barriers were discussed, which could arise when an existing combined cycle power plant is to be retrofitted to a low $CO_2$ emission power plant. This paragraph discusses the options to design the plant in such a way that a future retrofit can be executed without major costs and technical difficulties, caused by these barriers, while still maintaining an optimal performance before and after retrofit.
First step is to point out the possible barriers and try to remove them by implementing additional design requirements. Next to removing barriers for future retrofit, there are also possibilities for process integration between the fuel plant and the power plant. These can increase the economical feasibility of the project with a considerable amount.

Without being studied in detail, some indications are given to illustrate the impact that these issues may have.

### 8.2.1 Avoiding potential barriers

In paragraph 8.1 the barriers to retrofitting are discussed. When a CCPP is designed for future retrofit, these potential barriers should be avoided in the design phase. In this paragraph the possible solutions are mentioned to each of the above-mentioned barriers.

**Plot Space**
In the ideal situation of a completely new and empty site, the design should also include the additional required plot space for the fuel processing plant or the flue gas scrubber. The most ideal location for the installations with respect to the CCPP can be determined.
When the CCPP is placed in an area with little additional space available, the nearest possible free plot space should be determined and reserved. In this way no new building activities are deployed on that lot, until the final decision for retrofitting is made.
When post combustion $CO_2$ capture is decided, it is however necessary to reserve additional plot space at the CCPP plot. It is not desirable to transport the large flue gas volume over big distances.
In Appendix 3 the plot plans with sizes for the different installations can be found.

In addition to the required space for the installations themselves, attention should be paid to the space required for the construction activities. When space is available to store materials, tools and installation parts on site, the construction work can be done cheaper in comparison to an off-site construction area.

Reserving more plot space then strictly necessary for the CCPP plant only will result in higher project costs in the first phase, but will save expenses when retrofit is carried out.

Indications of plotspace needed for building the capture plants are:
Case 1: post combustion capture plant 250x150 m.
Case 2.1 and 2.2: gas reformed based pre combustion is capture plant 175x150 m.
Case 3.1 and 3.2: coal gasification based pre combustion capture plant 475 x 375 m.

**Available space in installation**
When the CCPP is designed for future retrofit, the future tie-ins have to be defined and the space they require becomes an additional design requirement.
For the pre combustion capture case this implies that space has to be reserved for large diameter (12"-36" dependant on the option concerned) fuel feed pipes to the gas turbine. The same applies for the large diameter low pressure steam line (approx. 36") in the post combustion option. Also when the replacement of equipment components is foreseen, the design should anticipate the incorporation of the new (possibly larger) component, as well as enable the replacement work itself. For example it might be necessary to replace the existing HRSG superheater section, to adjust the CCPP to the new process conditions. Taking these issues into account will lead to minor extra costs, while the cost savings at the retrofit stage can be significant.

Typically stretching the HRSG with a few meters and allow for some spare room for the heat surfaces concerned allows for a modification.

**Accessibility**
The accessibility of the plot should be considered as a design requirement at the choice for the most appropriate site location. Usually this aspect will already be part of the selection process for a new CCPP, and extra attention should be paid to the accessibility for the big components of the pre and post combustion capture installations.

**Changed process conditions**
A new power plant will generally be designed to perform in an optimal way at one set of process conditions, belonging to one type of fuel, one average ambient condition, etcetera. An important option to facilitate retrofitting a CCPP is to design the plant with keeping in mind that process conditions change due to the retrofit.
At the pre combustion capture case the exhaust gas temperature decreases when the gas turbine is fired on low-LHV fuel gas. This implies that the high-pressure steam superheater cannot raise the steam temperature to the original design value, as the surface area is too small at these different flue gas conditions. This could cause technical problems and it may even be necessary to exchange the superheater with a new, larger one.
During the design phase it could be considered to install the larger superheater, which will be able to raise the steam temperature to the original design value. This superheater will then be equipped with an attemperator to cool down the steam temperature when the gas turbine is fired on normal LHV (natural) gas. Installing a larger superheater will be more expensive and reduce efficiency in the CCPP. However it improves efficiency and saves costs in retrofit.

For the post combustion case there is no remedy to undo the higher pressure loss due to the flue gas scrubber unit. An induced draft fan could be installed during retrofitting in the flue gas ducting to overcome this extra loss, but this will also increase the auxiliary power consumption (because of the power needed to drive the fan). Extra plot space for enabling the installation of this fan should be provided for.

**Cooling water capacity**
The cooling water intake and outlet stations should be designed to have sufficient capacity to take the increase in cooling water demand because of the fuel processing plant or the flue gas scrubber. The stations can be designed to facilitate for example extra cooling water pumps, without the need for installing these pumps right away. This will give flexibility to increase the cooling water capacity without having to perform large civil works for expansion.

The cooling water capacity for the various capture plants is:

- coal gasification based local pre combustion capture plant 83,000 $m^3$/h.
- gas reformed based local pre combustion is capture plant 21,000 $m^3$/h.
- post combustion capture plant 46,000 m3/h.

The cooling water requirement of the CCPP for the different cases can be found in Appendix 1, stream 5. For the reference case the maximum cooling water load applies, which is approximately 27,000 $m^3$/h.

**Operational Flexibility**
It is difficult to design for a higher level of operational flexibility when the gas turbines are fired on low-LHV gas. Process integration between the pre combustion capture plant and the CCPP could help, as will be discussed in the following paragraph.

**Permitting**
As permitting can be a real problem, it is advisable to start the requests for the required permits as early as possible. This could mean that the application for the permits needed for the situation after retrofit, could best be started together with the permits for the CCPP. This will decrease the change on surprises as well as it will avoid lost time when the decision for retrofitting is made.

**Construction and Start-up**
Planned down time of the CCPP can be minimised when additional facilities for making the tie-ins with the CCPP in operation (Hot-tapping) are allowed for during construction.

### 8.2.2 Potential process integration

In addition to trying to remove potential barriers to future retrofit, it can be rewarding to design the CCPP in such a way that process integration can be obtained between the CCPP and the post or pre combustion capture plants. This could lead to cost savings as well as performance improvements compared to not-integrated plants. This paragraph indicates the potential options for process integration.

**Gas Turbine Compressor Bleed**
The Capture Plant requires high-pressure air, which is supplied by a dedicated compressor. At the power plant however, the gas turbine compressor is partially by-passed by closing the IGV's, in order to retain the fuel gas flow through the gas turbine expander section.
Here process integration can be achieved by using the highly efficient gas turbine compressor section to supply (part of) the high-pressure air for the Capture Plant. This has multiple advantages:

- Gas turbine compressor sections are state of the art compressors, with highest efficiencies. The efficiency of the gas turbine compressor will usually be higher then the efficiency of the dedicated compressor.
- Investment costs will be lower as the dedicated compressor can be designed for a smaller airflow or smaller pressure ratio.
- The gas turbine compressor section will take the airflow it was designed for and at which its efficiency is highest. This contrary to the non-integration case at which IGV's are used to decrease the flow through the compressor.
- The CCPP part load efficiency is increased, as the IGV control is once again completely available to reduce the gas turbine load.

As the natural gas fuelled (local) pre combustion $CO_2$ capture plant is provided with high efficient air compressor units with minimum intercooling the potential efficiency increase by implementing gas turbine compressor bleed is marginal. However it will have a positive impact on the overall cost of investment because of the reduction of air compressor capacity required. An overall cost reduction of approx. 7% of the fuel/$CO_2$ capture plant is expected.

For the coal gasification based (local) pre combustion $CO_2$ capture plant also potential efficiency increase is expected because for the ASU highly intercooled compressor units are used. This configuration aims for the minimum compressor power required, but results in a high loss of thermal energy via the cooling water system which has a negative impact on the overall plant efficiency.

To achieve a bleed flow from the gas turbine compressor outlet, the gas turbine needs to be equipped with a special bleed system. This will probably be too expensive when an existing gas turbine without air bleed is retrofitted. However when the power plant is designed for retrofit, the gas turbine can be ordered with an air bleed system installed. Of course this process integration is only feasible in the local cases as it will not be efficient to bring the compressed air from the power plant through a 40 km pipeline to the Capture Plant.

**Integral water-steam cycle**
The pre combustion capture plant has a dedicated steam turbine to expand the steam generated in the process and produce electricity. This steam turbine is a relatively small turbine, with high investment costs and a relatively low efficiency (compared to large scale power plant steam turbines). The power plant has such a large steam turbine generator and therefore process integration can be achieved here by feeding the steam from the Capture Plant to the power plant steam turbine. This has the following advantages:

- Small steam turbines have higher specific investment cost, and it is usually less expensive to purchase a somewhat larger steam turbine for the power plant with an

increased capacity to be able to accept the additional Capture Plant steam production.
- The large steam turbine has a higher efficiency than the small turbine, so the steam expansion and electricity production is more efficient in the large turbine. Additional advantage is the need for only one cooling water system. The larger steam turbine will also come with a larger condenser, so there is no need for a dedicated condenser for the fuel plant.
- The integration will save valuable plot space.

However, as the steam generation in the fuel plant (approx 300-550 t/h) is rather significant compared to the CCCP steam production (approx. 2*350 t/h), this will highly effect the steam turbine design of the CCCP. It requires a more detailed study to assess the overall impact and potential.

Again this process integration option is only feasible in the local cases as it will not be efficient to transport high pressure steam over 40 km in the remote cases.

The same arguments as above can be used to plead for a combined instead of a dedicated demin water plant and closed cooling water system.

## 8.3 OVERALL AVAILABILITY

### 8.3.1 Availability rating

The overall availability of a plant is mainly dependent on the following issues:

- complexity of the installation and/or process
- project experiences with the type of installation concerned (i.e. references)
- design philosophy of the plant (i.e. redundancy of critical equipment, control and safeguarding systems, etc.).

In *Table 8.1* an overview of the availability rating for the various plants concerned for this study is presented:

| | Complexity | References * | Design | Overall rating |
|---|---|---|---|---|
| Reference plant | ++ | ++ | ++ | ++ |
| Case 1 | + | o | ++ | + |
| Case 2.1 | o | o/- | ++ | o |
| Case 2.2 | o | o/- | ++ | o |
| Case 3.1 | -- | o/- | ++ | - |
| Case 3.2 | -- | o/- | ++ | - |

***Table 8.1 - Availability Rating***

* There are presently hardly any $CO_2$ capture plants realized but in case there are similar types of plants in operation this is also taken into account.

From the table it becomes clear that the expected overall availability for the retrofitted plants is lower than the expected availability for the reference plant. This is in principle an expected result, as the retrofitted plant comprises not only additional plant sections (i.e. additional systems and equipment, which may fail and require maintenance) but also rather complex installations (especially the coal based plants).

However when evaluating the availability of power generation it is possible to obtain a similar availability for all plants by providing sufficient provisions to allow for independent operation of the CCPP. The required provisions for each case are presented below.

In all cases, the capture plant is designed to have an availability of at least 90%. This is achieved by installing spares in key services. For example, all pumps, the gasifiers and sulphur plants in cases 3-1 and 3-2, and the desulphurisation reactors in Cases 2-1 and 2-2 are spared.

In all cases, provided the CCPP is allowed to operate without capturing 85% of the carbon in the feed, then the installation of the Capture Plant does not affect the availability of the CCPP.

### 8.3.2 Case 1 Post combustion $CO_2$ capture

A bypass stack with (automatic) switch over facilities between the HRSG sections and the $CO_2$ capture plant shall be provided in order to discharge the flue gas to the atmosphere or to the $CO_2$ capture plant.

The effect of the failure of a single quench and acid gas removal train would mean that, provided that the exhaust gases could be vented, $CO_2$ capture would be reduced by 12.5%. It is unlikely that the additional exhaust gas could be routed through the remaining quench and acid gas removal units, as this would increase pressure drops by up to 70% and overload the absorber feed fan. Failure of multiple quench and acid gas removal trains would result in further reductions in $CO_2$ capture and increases in the steam turbine generator condenser requirements. Alternatively, the CCPP for the failed quench and acid gas removal train, could be turned down to 75% of capacity, removing the need for venting of exhaust gas.

The effect of failure of a $CO_2$ compressor and dryer unit would be to reduce the $CO_2$ capture by 50%. The exhaust gas from the HRSG could be routed to the existing stack and the CCPP operated as before the Capture Plant was installed.

### 8.3.3 Case 2 Pre combustion $CO_2$ capture by syngas production from natural gas

The Capture Plant has two trains of desulphurisation, auto-thermal reformer, high temperature cooling, shift, low temperature cooling, acid gas removal, $CO_2$ compressor and dryer, and gas conditioning. A failure of any one of these process units means that the capture plant train is shut down and the feed of low carbon fuel to one gas turbine is stopped.

Therefore the gas turbine shall be provided with a conventional dual fuel system capable of firing 100 % syngas as well as 100 % natural gas. Steam injection will be required for $NO_x$ abatement during firing natural gas.

### 8.3.4 Case 3 Pre combustion $CO_2$ capture by syngas production from coal

The Capture Plant has two trains of coal slurrying and grinding, gasification, shift, low temperature cooling, acid gas removal, $CO_2$ compressor and dryer, and gas conditioning. Failure of coal slurrying and grinding, gasification, shift, low temperature cooling, acid gas removal, or gas conditioning results in shut down of one train of the Capture Plant and one gas turbine is running on natural gas in stead of syngas. A spare gasifier is foreseen in the design of the Capture Plant (5 * 25% gasifiers).

Therefore the gas turbine shall be provided with a conventional dual fuel system capable of firing 100 % syngas as well as 100 % natural gas. Steam injection will be required for $NO_x$ abatement during firing natural gas.

If the $CO_2$ compressor and dryer, $CO_2$ export pipeline or $CO_2$ sink fails, then fuel gas can be supplied to the CCPP, which operates as normal, except that $CO_2$ is vented to atmosphere, rather than being captured.

### 8.3.5 Availability during start-up

It shall be clear that the provisions mentioned above are also strongly preferred or even required for start-up and shut down purposes and are therefore implemented anyhow and not lead to additional capital cost.

In the year of retrofit the CCPP availability may decrease because of the down time to allow for implementing modifications and tie-in activities. In case of a good preparation and a tight schedule it is considered possible to make all tie-ins and implement the required modifications within approximately 1 month. For case 1, post combustion $CO_2$ capture, it may even be possible to realize the project without additional down time when all tie-ins have been prepared in advance (i.e. during a planned outage of the CCPP). For the pre combustion $CO_2$ capture cases a complete new combustion system has to be installed. This system will normally not be installed in advance as it will have a negative impact on the power plant performance (steam injection required when firing natural gas).

In case the modifications are executed during a major overhaul period the impact on the plant availability will be negligible for all cases.

Also during the initial commissioning/operating period the availability will be lower due to the ‘normal’ issues, which always rise during the initial start-up of an installation. It is normal practice that the higher the complexity of the installation the longer it takes to reach the stable operating mode.

To minimize the CCPP plant availability reduction during the commissioning/start-up period it is preferred to have a postponed schedule for the second power train. Experiences gained during start up of the first train can be used when starting up the second train.

# 9. CONCLUSIONS

From the study it becomes clear that a retrofit of $CO_2$ capture to a natural gas fired CCCP requires a significant cost of investment and results also in a significant reduction of the overall electric efficiency. The post combustion $CO_2$ capture option is strongly preferred from a performance and financial point of view compared to the natural gas reforming and the coal gasification based pre combustion $CO_2$ capture plants.

The post combustion option shows the smallest but still significant efficiency reduction in combination with the lowest capital expenditures and the best specific $CO_2$ emission.

The main disadvantage of the post combustion option is the requirement of installing the plant almost next to the existing CCCP because of the large atmospheric flue gas flow. As the plant requires also a large plot space, this could be a problem for retrofitting.

The main data for all options studied are presented in table 9.1

| | | **Ref.** | **1** | **2.1** | **2.2** | **3.1** | **3.2** |
|---|---|---|---|---|---|---|---|
| Capital expenditure*) | MUSD | 415 | 395 | 569 | 750 | 962 | 1194 |
| Specific electricity cost**) | USD/MWh | 30.0 | | | | | |
| Cost of avoided $CO_2$ | USD/ton $CO_2$ | --- | 73.2 | 95.1 | 124.3 | 131.4 | 168.1 |
| Overall efficiency | % | 55.9 | 44.6 | 41.5 | 39.9 | 35.4 | 33.6 |
| Fuel consumption (LHV) | MWth | 1405 | 1405 | 1672 | 1671 | 2121 | 2306 |
| Net power production | MWe | 785 | 626 | 694 | 667 | 751 | 775 |
| $CO_2$ emission | kg/s | 81.4 | 11.7 | 13.9 | 13.9 | 27.1 | 30.2 |
| Specific $CO_2$ emission | g/kWh | 373 | 67 | 72 | 75 | 130 | 140 |
| Relative $CO_2$ emission | % | 100 | 17.9 | 19.4 | 20.0 | 34.8 | 37.5 |
| Relative $CO_2$ capture efficiency***) | % | 0 | 82.1 | 80.6 | 80.0 | 65.2 | 62.5 |

***Table 9.1 – Overall performance comparison***

Ref : Natural gas fired CCCP
1 : Post combustion $CO_2$ capture
2.1 : Pre combustion $CO_2$ capture (natural gas reforming, local)
2.2 : Pre combustion $CO_2$ capture (natural gas reforming, remote)
3.1 : Pre combustion $CO_2$ capture (coal gasification, local)
3.2 : Pre combustion $CO_2$ capture (coal gasification, remote)

*) The capital expenditures for the fuel/$CO_2$ capture plant are excluding the cost of the reference CCCP.

**) The specific electricity costs are calculated for the project with a Net Present Value (NPV) of 0.

***) The absolute capture efficiency for all plants is approx. 85%. However, as retrofitting reduces the efficiency, the relative capture efficiency decreases.

Other conclusions are:

- All options comply with the $CO_2$ capture efficiency of 85%.
- The remote pre combustion options require a higher cost of investment and have a lower efficiency due to transportation of the fuel gas.
- The overall power generation availability of the retrofitted plant is “identical” to the reference CCCP.
- Sensitivity analyses on fuel price show a different behaviour of the cost of avoided $CO_2$ for the coal-based plants compared to the natural gas fuelled plants. An increase of the fuel price results in an increase in the cost of avoided $CO_2$ for the natural gas fuelled plants and a decrease of cost for the coal fuelled plants. In case of a fuel price reduction the opposite occurs. Sensitivity analysis on discount rate show, as expected, a reduction of the costs of avoided $CO_2$ for all cases considered with a reduced discount rate.
- Sensitivity analyses on the year of retrofit show as expected that when the retrofit is executed at a later time, the cost of avoided $CO_2$ increase.
- The post combustion option remains the best option from a financial point of view for all sensitivities considered.

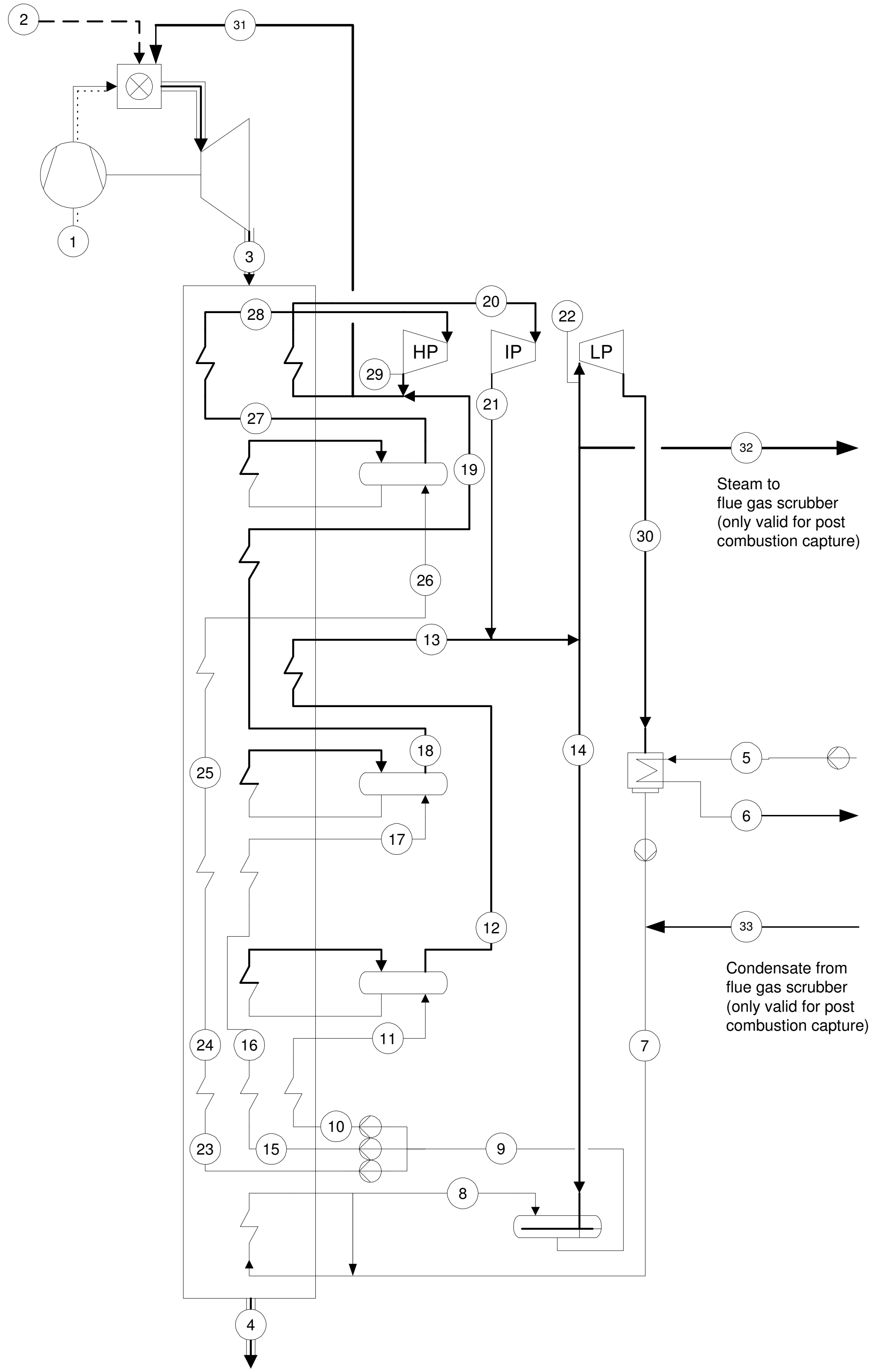
## APPENDICES

1. CCPP Simplified Process Scheme & Mass Balances
2. Fuel/$CO_2$ Capture Plants Simplified Process Schemes & Mass Balances
3. Plot Lay-outs
4. Fuel/$CO_2$ Capture Plants Equipment List
5. Fuel/$CO_2$ Capture Plants Power Consumption/Production & Utility Usage
6. Fuel/$CO_2$ Capture Plants Capital Cost Estimates
7. Cash Flow Calculations
8. Task 1 – Same Output Retrofit
9. Task 3 – Pre-Implementation Retrofit

# Appendix 1

CCPP Simplified Process Scheme and Mass Balance

# CCPP SCHEME



2
31
1
3
28
20
22
HP
IP
LP
29
21
27
19
32
Steam to
flue gas scrubber
(only valid for post
combustion capture)
30
26
13
18
14
5
25
6
17
12
33
Condensate from
flue gas scrubber
(only valid for post
combustion capture)
24
16
11
7
10
23
15
9
8
4

**Mass balance standard power plant**
**Reference Case**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | N.A. | N.A. | N.A. | N.A. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Flow | kg/sec | 618.2 | 15.0 | 633.2 | 633.2 | 7508.0 | 7508.0 | 96.9 | 96.9 | 99.2 | 10.7 |
| Pressure | bar | 1.0 | 40.0 | 1.0 | 1.0 | 2.0 | 1.0 | 8.0 | 8.0 | 1.2 | 5.0 |
| Temperature | C | 9 | 10 | 608 | 99 | 12 | 19 | 29 | 90 | 105 | 105 |
| Enthalpy | kJ/kg | -6 | -11 | 656 | 87 | 51 | 80 | 122 | 377 | 439 | 440 |

| | | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 |
| Flow | kg/sec | 10.7 | 10.7 | 10.7 | 2.3 | 11.4 | 11.4 | 11.4 | 11.4 | 11.4 | 88.5 |
| Pressure | bar | 4.9 | 4.7 | 4.6 | 4.6 | 28.3 | 28.2 | 28.1 | 27.5 | 27.4 | 27.0 |
| Temperature | C | 148 | 150 | 300 | 318 | 105 | 140 | 227 | 229 | 300 | 560 |
| Enthalpy | kJ/kg | 624 | 2745 | 3066 | 3102 | 444 | 591 | 977 | 2802 | 3003 | 3593 |

| | | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 | 0.93 |
| Flow | kg/sec | 88.5 | 96.9 | 77.1 | 77.1 | 77.1 | 77.1 | 77.1 | 77.1 | 77.1 | 96.9 |
| Pressure | bar | 4.6 | 4.6 | 122.3 | 122.2 | 122.1 | 122.0 | 121.0 | 120.0 | 27.4 | 0.04 |
| Temperature | C | 320 | 318 | 107 | 140 | 221 | 323 | 325 | 560 | 346 | 29 |
| Enthalpy | kJ/kg | 3107 | 3102 | 457 | 597 | 951 | 1480 | 2687 | 3505 | 3114 | 2384 |

| | | 31 |
|---|---|---|
| Quality | | 1.00 |
| Flow | kg/sec | 0.0 |
| Pressure | bar | 27.0 |
| Temperature | C | 560 |
| Enthalpy | kJ/kg | 3593 |

**NO FUEL PREHEATING AT CCPP**

**Mass balance standard power plant**
**Case 1 Post Combustion**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | N.A. | N.A. | N.A. | N.A. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Flow | kg/sec | 618.2 | 15.0 | 633.2 | 633.2 | 4496.6 | 4496.6 | 10.8 | 96.8 | 99.2 | 10.7 |
| Pressure | bar | 1.0 | 40.0 | 1.0 | 1.0 | 2.0 | 1.0 | 8.0 | 8.0 | 1.2 | 5.0 |
| Temperature | C | 9 | 10 | 608 | 99 | 12 | 14 | 15 | 90 | 105 | 105 |
| Enthalpy | kJ/kg | -6 | -11 | 656 | 87 | 51 | 57 | 64 | 376 | 439 | 440 |

| | | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 |
| Flow | kg/sec | 10.7 | 10.7 | 10.7 | 2.3 | 11.4 | 11.4 | 11.4 | 11.4 | 11.4 | 88.5 |
| Pressure | bar | 4.9 | 4.7 | 4.6 | 4.6 | 28.3 | 28.2 | 28.1 | 27.5 | 27.4 | 27.0 |
| Temperature | C | 148 | 150 | 300 | 318 | 105 | 140 | 227 | 229 | 300 | 560 |
| Enthalpy | kJ/kg | 624 | 2745 | 3066 | 3102 | 444 | 591 | 977 | 2802 | 3003 | 3593 |

| | | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Flow | kg/sec | 88.5 | 10.8 | 77.1 | 77.1 | 77.1 | 77.1 | 77.1 | 77.1 | 77.1 | 10.8 |
| Pressure | bar | 4.6 | 4.6 | 122.3 | 122.2 | 122.1 | 122.0 | 121.0 | 120.0 | 27.4 | 0.02 |
| Temperature | C | 320 | 318 | 107 | 140 | 221 | 323 | 325 | 560 | 346 | 18 |
| Enthalpy | kJ/kg | 3107 | 3102 | 457 | 597 | 951 | 1480 | 2687 | 3505 | 3114 | 2534 |

| | | 31 | 32 | 33 |
|---|---|---|---|---|
| Quality | | 1.00 | 1.00 | 0.00 |
| Flow | kg/sec | 0.0 | 86.0 | 86.0 |
| Pressure | bar | 27.0 | 4.6 | 8.0 |
| Temperature | C | 560 | 318 | 30 |
| Enthalpy | kJ/kg | 3593 | 3102 | 126 |

**NO FUEL PREHEATING AT CCPP**

**Mass balance standard power plant**
**Case 2-1, local H2, Nat Gas**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | N.A | N.A | N.A | N.A | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Flow | kg/sec | 535.3 | 89.7 | 625.1 | 625.1 | 7204.1 | 7204.1 | 93.5 | 93.5 | 95.3 | 12.1 |
| Pressure | bar | 1.0 | 30.0 | 1.0 | 1.0 | 2.0 | 1.0 | 8.0 | 8.0 | 1.2 | 5.1 |
| Temperature | C | 9.0 | 230.0 | 565.1 | 101.8 | 12 | 19 | 29 | 93 | 105 | 105 |
| Enthalpy | kJ/kg | -6 | 422 | 631 | 94 | 51 | 80 | 121 | 388 | 439 | 440 |

| | | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 |
| Flow | kg/sec | 12.1 | 12.1 | 12.1 | 1.8 | 13.9 | 13.9 | 13.9 | 13.9 | 13.9 | 83.2 |
| Pressure | bar | 4.9 | 4.7 | 4.6 | 4.6 | 28.4 | 28.2 | 28.1 | 27.5 | 27.3 | 27.0 |
| Temperature | C | 149 | 150 | 305 | 306 | 105 | 140 | 230 | 229 | 291 | 531 |
| Enthalpy | kJ/kg | 628 | 2745 | 3076 | 3078 | 444 | 592 | 988 | 2802 | 2980 | 3528 |

| | | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 | 0.92 |
| Flow | kg/sec | 83.2 | 93.5 | 69.3 | 69.3 | 69.3 | 69.3 | 69.3 | 69.3 | 69.3 | 93.5 |
| Pressure | bar | 4.6 | 4.6 | 122.1 | 122.1 | 122.0 | 121.9 | 120.9 | 120.1 | 27.3 | 0.04 |
| Temperature | C | 306 | 306 | 107 | 142 | 225 | 324 | 325 | 526 | 330 | 29 |
| Enthalpy | kJ/kg | 3077.9 | 3078 | 457 | 606 | 970 | 1489 | 2687 | 3419 | 3077 | 2371 |

| | | 31 |
|---|---|---|
| Quality | | 1.00 |
| Flow | kg/sec | 0.0 |
| Pressure | bar | 27.0 |
| Temperature | C | 530.9 |
| Enthalpy | kJ/kg | 3528 |

**NO FUEL PREHEATING AT CCPP**

**Mass balance standard power plant**
**Case 2-2, remote H2, Nat Gas**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | N.A. | N.A. | N.A. | N.A. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Flow | kg/sec | 536.2 | 77.9 | 626.1 | 626.1 | 6052.5 | 6052.5 | 73.2 | 85.2 | 86.4 | 8.3 |
| Pressure | bar | 1.0 | 25.0 | 1.0 | 1.0 | 2.0 | 1.0 | 3.0 | 3.0 | 1.2 | 4.9 |
| Temperature | C | 9 | 215 | 564 | 103 | 12 | 19 | 27 | 96 | 105 | 105 |
| Enthalpy | kJ/kg | -6 | 385 | 630 | 95 | 48 | 75 | 115 | 400 | 439 | 440 |

| | | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 |
| Flow | kg/sec | 8.3 | 8.3 | 8.3 | 1.2 | 11.4 | 11.4 | 11.4 | 15.5 | 11.4 | 66.1 |
| Pressure | bar | 4.9 | 4.7 | 4.6 | 4.6 | 28.1 | 28.0 | 27.9 | 27.3 | 27.2 | 27.0 |
| Temperature | C | 151 | 149 | 314 | 334 | 105 | 143 | 230 | 229 | 300 | 539 |
| Enthalpy | kJ/kg | 638 | 2744 | 3094 | 3136 | 444 | 605 | 998 | 2802 | 3004 | 3546 |

| | | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 | 0.94 |
| Flow | kg/sec | 66.1 | 73.2 | 66.8 | 66.8 | 66.8 | 66.8 | 66.8 | 66.8 | 66.8 | 73.2 |
| Pressure | bar | 4.6 | 4.6 | 122.0 | 121.9 | 121.8 | 121.7 | 120.7 | 120.0 | 27.2 | 0.04 |
| Temperature | C | 337 | 334 | 107 | 144 | 228 | 326 | 325 | 539 | 343 | 27 |
| Enthalpy | kJ/kg | 3141 | 3136 | 457 | 615 | 982 | 1499 | 2688 | 3452 | 3107 | 2403 |

| | | 31 |
|---|---|---|
| Quality | | 1.00 |
| Flow | kg/sec | 12.0 |
| Pressure | bar | 27.2 |
| Temperature | C | 337 |
| Enthalpy | kJ/kg | 3092 |

**3 stage fuel preheating with saturated steam**

| | | |
|---|---|---|
| **HP** | 9.5 | kg/s |
| **MP** | 4.1 | kg/s |
| **LP** | 4.8 | kg/s |

**NOTE: taken from evaporators**

**Mass balance standard power plant**
**Case 3-1, local H2, Coal**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | N.A. | N.A. | N.A. | N.A. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Flow | kg/sec | 523.2 | 103.7 | 626.9 | 626.9 | 7108.6 | 7108.6 | 92.1 | 92.1 | 93.9 | 11.9 |
| Pressure | bar | 1.0 | 25.9 | 1.0 | 1.0 | 2.0 | 1.0 | 8.0 | 8.0 | 1.2 | 5.0 |
| Temperature | C | 9 | 230 | 565 | 101 | 12 | 19 | 29 | 93 | 105 | 105 |
| Enthalpy | kJ/kg | -6 | 363 | 620 | 91 | 51 | 80 | 121 | 389 | 439 | 440 |

| | | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 |
| Flow | kg/sec | 11.9 | 11.9 | 11.9 | 1.7 | 13.6 | 13.6 | 13.6 | 13.6 | 13.6 | 82.0 |
| Pressure | bar | 4.9 | 4.7 | 4.6 | 4.6 | 28.4 | 28.2 | 28.1 | 27.5 | 27.3 | 27.0 |
| Temperature | C | 149 | 150 | 305 | 308 | 105 | 140 | 230 | 229 | 291 | 531 |
| Enthalpy | kJ/kg | 628 | 2745 | 3077 | 3081 | 444 | 592 | 988 | 2802 | 2981 | 3530 |

| | | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 | 0.93 |
| Flow | kg/sec | 82.0 | 92.1 | 68.4 | 68.4 | 68.4 | 68.4 | 68.3 | 68.3 | 68.3 | 92.1 |
| Pressure | bar | 4.6 | 4.6 | 122.1 | 122.0 | 121.9 | 121.8 | 120.8 | 120.1 | 27.3 | 0.04 |
| Temperature | C | 308 | 308 | 107 | 142 | 225 | 324 | 325 | 528 | 333 | 29 |
| Enthalpy | kJ/kg | 3082 | 3081 | 457 | 606 | 970 | 1488 | 2687 | 3424 | 3083 | 2373 |

| | | 31 |
|---|---|---|
| Quality | | 1.00 |
| Flow | kg/sec | 0.0 |
| Pressure | bar | 27.0 |
| Temperature | C | 531 |
| Enthalpy | kJ/kg | 3530 |

**NO FUEL PREHEATING AT CCPP**

**Mass balance standard power plant**
**Case 3-2; remote H2, Coal**

| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | N.A. | N.A. | N.A. | N.A. | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Flow | kg/sec | 531.7 | 89.7 | 627.3 | 627.3 | 6417.0 | 6417.0 | 77.9 | 83.8 | 84.7 | 8.3 |
| Pressure | bar | 1.0 | 21.0 | 1.0 | 1.0 | 2.0 | 1.0 | 3.0 | 3.0 | 1.2 | 4.9 |
| Temperature | C | 9 | 223 | 567 | 103 | 12 | 19 | 28 | 98 | 105 | 105 |
| Enthalpy | kJ/kg | -6 | 371 | 627 | 94 | 48 | 75 | 117 | 409 | 439 | 440 |

| | | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 0.00 | 1.00 | 1.00 | 1.00 | 0.00 | 0.00 | 0.01 | 1.00 | 1.00 | 1.00 |
| Flow | kg/sec | 8.3 | 8.3 | 8.3 | 1.0 | 11.2 | 11.2 | 11.2 | 15.6 | 11.2 | 70.5 |
| Pressure | bar | 4.9 | 4.7 | 4.6 | 4.6 | 28.1 | 28.0 | 28.0 | 27.4 | 27.3 | 27.0 |
| Temperature | C | 151 | 149 | 315 | 329 | 105 | 144 | 230 | 229 | 300 | 540 |
| Enthalpy | kJ/kg | 639 | 2744 | 3096 | 3125 | 444 | 606 | 999 | 2802 | 3005 | 3548 |

| | | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Quality | | 1.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 1.00 | 1.00 | 0.94 |
| Flow | kg/sec | 70.5 | 77.9 | 65.2 | 65.2 | 65.2 | 65.2 | 65.2 | 65.2 | 65.2 | 77.9 |
| Pressure | bar | 4.6 | 4.6 | 121.9 | 121.9 | 121.8 | 121.7 | 120.7 | 120.0 | 27.3 | 0.04 |
| Temperature | C | 330 | 329 | 107 | 145 | 228 | 326 | 325 | 543 | 348 | 28 |
| Enthalpy | kJ/kg | 3128 | 3125 | 457 | 616 | 985 | 1500 | 2688 | 3460 | 3118 | 2397 |

| | | 31 |
|---|---|---|
| Quality | | 1.00 |
| Flow | kg/sec | 5.9 |
| Pressure | bar | 27.3 |
| Temperature | C | 341 |
| Enthalpy | kJ/kg | 3102 |

**3 stage fuel preheating with saturated steam**

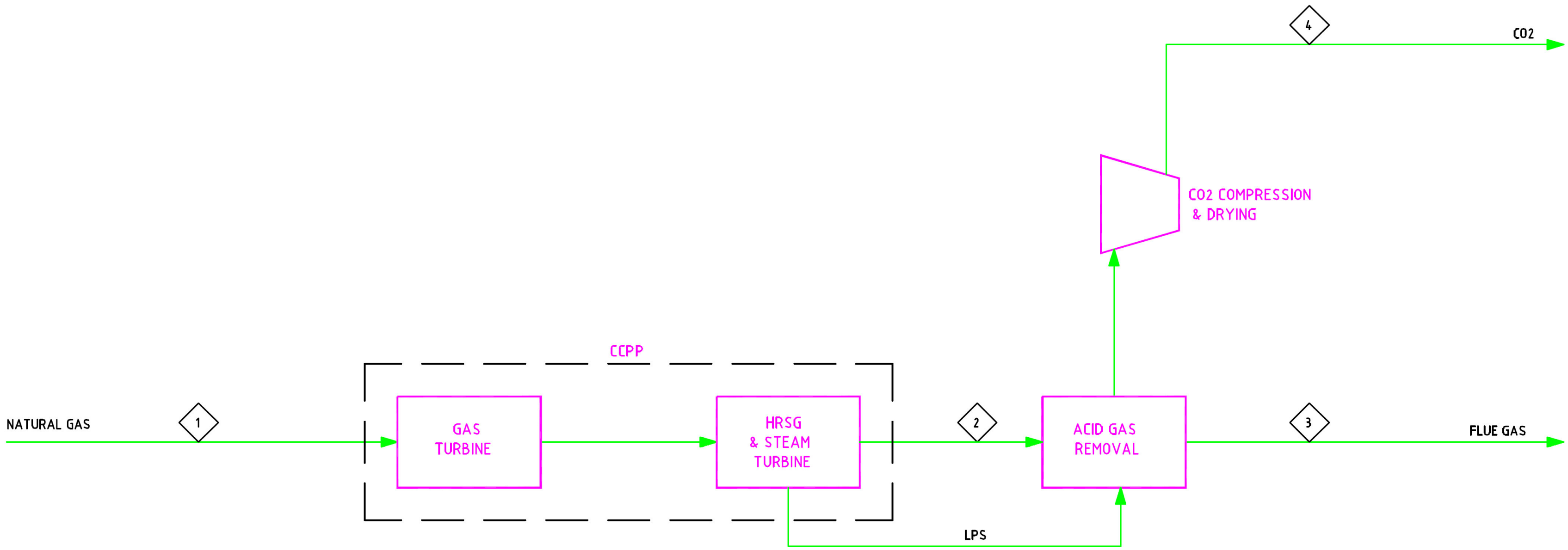
| | | |
|---|---|---|
| **HP** | 11.2 | kg/s |
| **MP** | 4.4 | kg/s |
| **LP** | 4.9 | kg/s |

**NOTE: taken from evaporators**

# Appendix 2

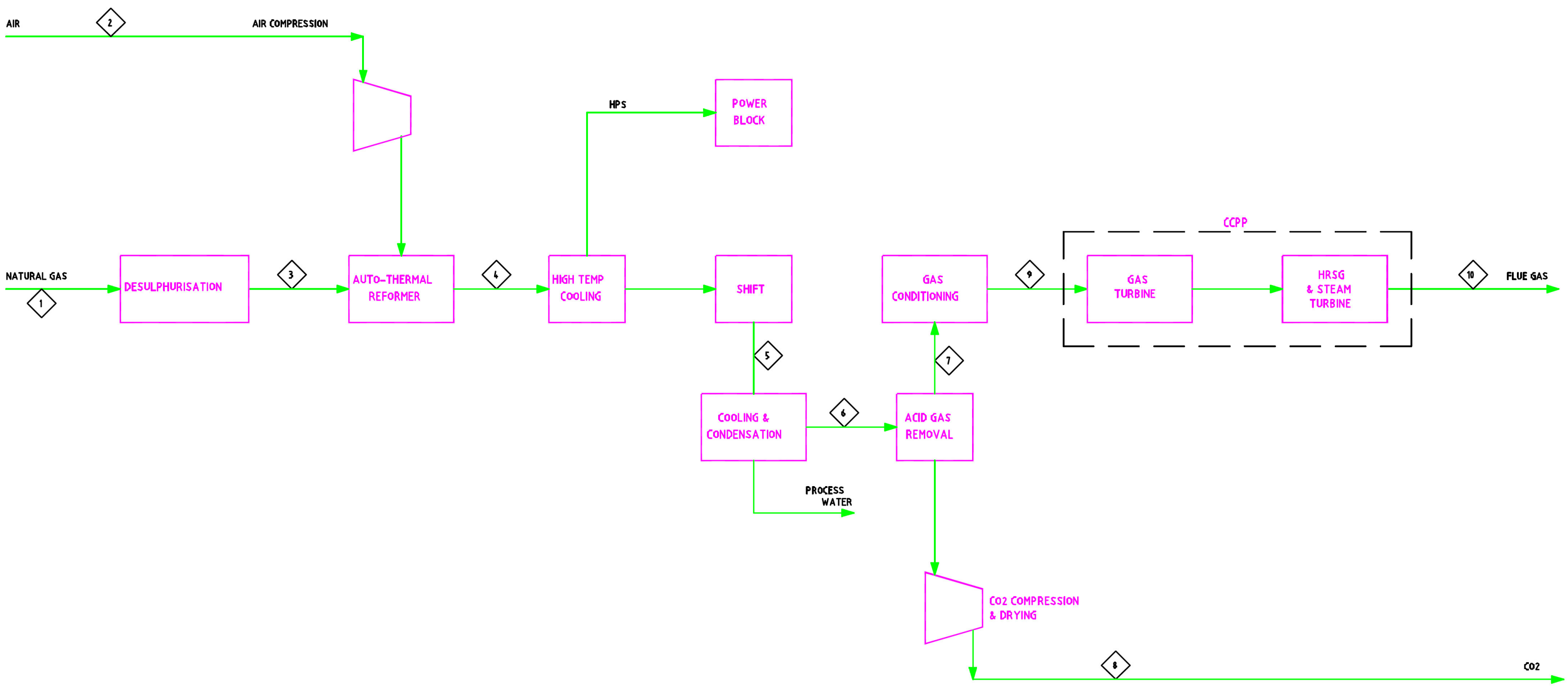
Fuel/$CO_2$ Capture Plants Simplified Process Schemes and Mass Balances

# Case 1

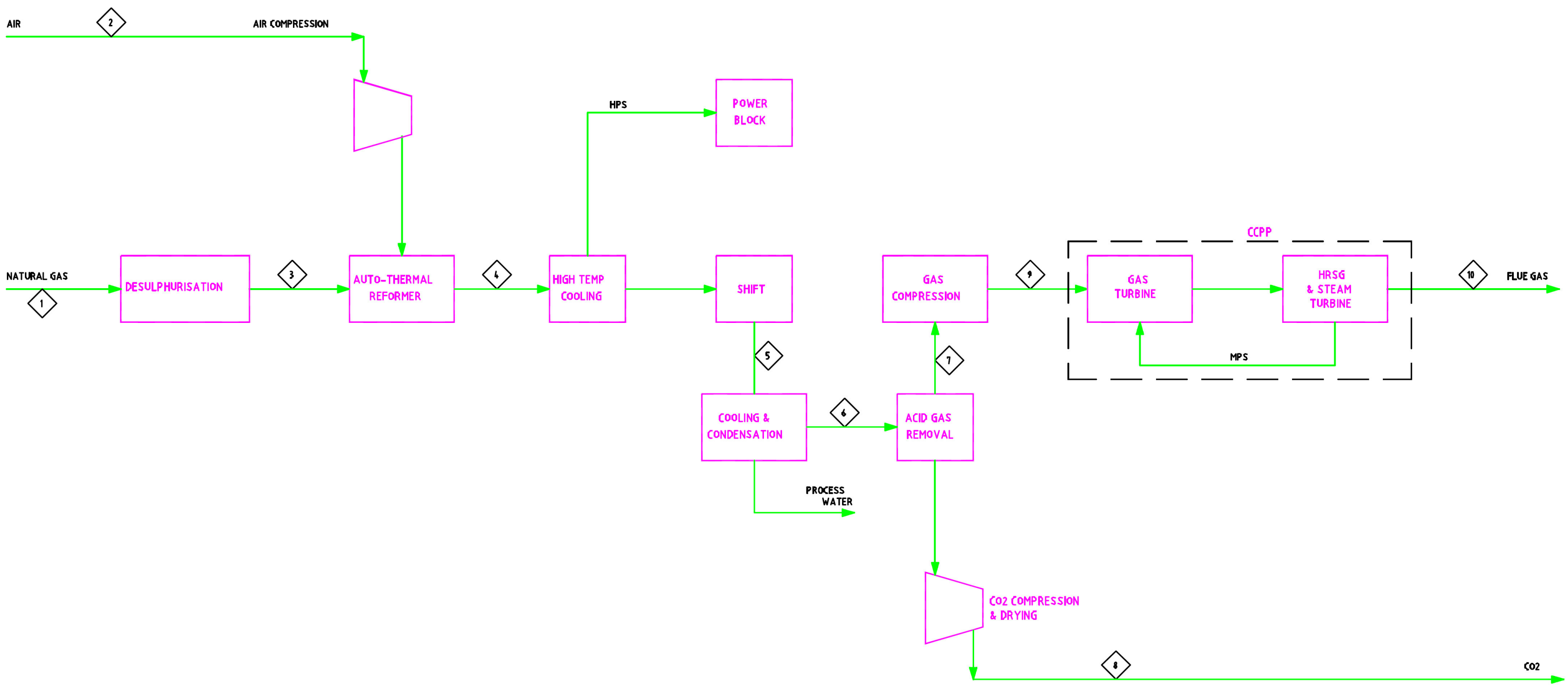


CO2
4
CO2 COMPRESSION
& DRYING
CCPP
NATURAL GAS
1
GAS
TURBINE
HRSG
& STEAM
TURBINE
2
ACID GAS
REMOVAL
3
FLUE GAS
LPS

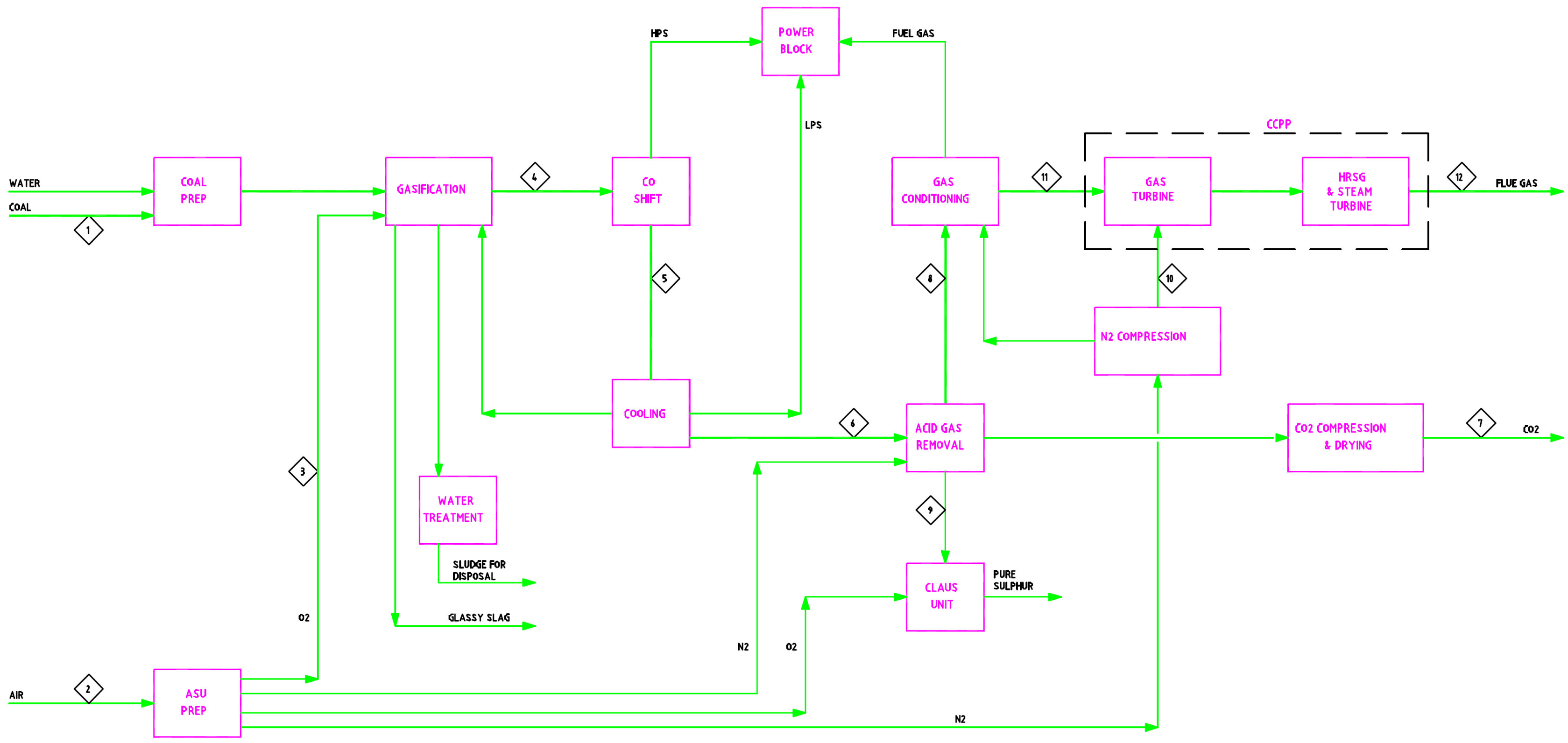
# Case 2-1


AIR
2
AIR COMPRESSION
HPS
POWER BLOCK
NATURAL GAS
1
DESULPHURISATION
3
AUTO-THERMAL REFORMER
4
HIGH TEMP COOLING
SHIFT
5
COOLING & CONDENSATION
6
ACID GAS REMOVAL
7
GAS CONDITIONING
9
CCPP
GAS TURBINE
HRSG & STEAM TURBINE
10
FLUE GAS
PROCESS WATER
CO2 COMPRESSION & DRYING
8
CO2

# Case 2-2

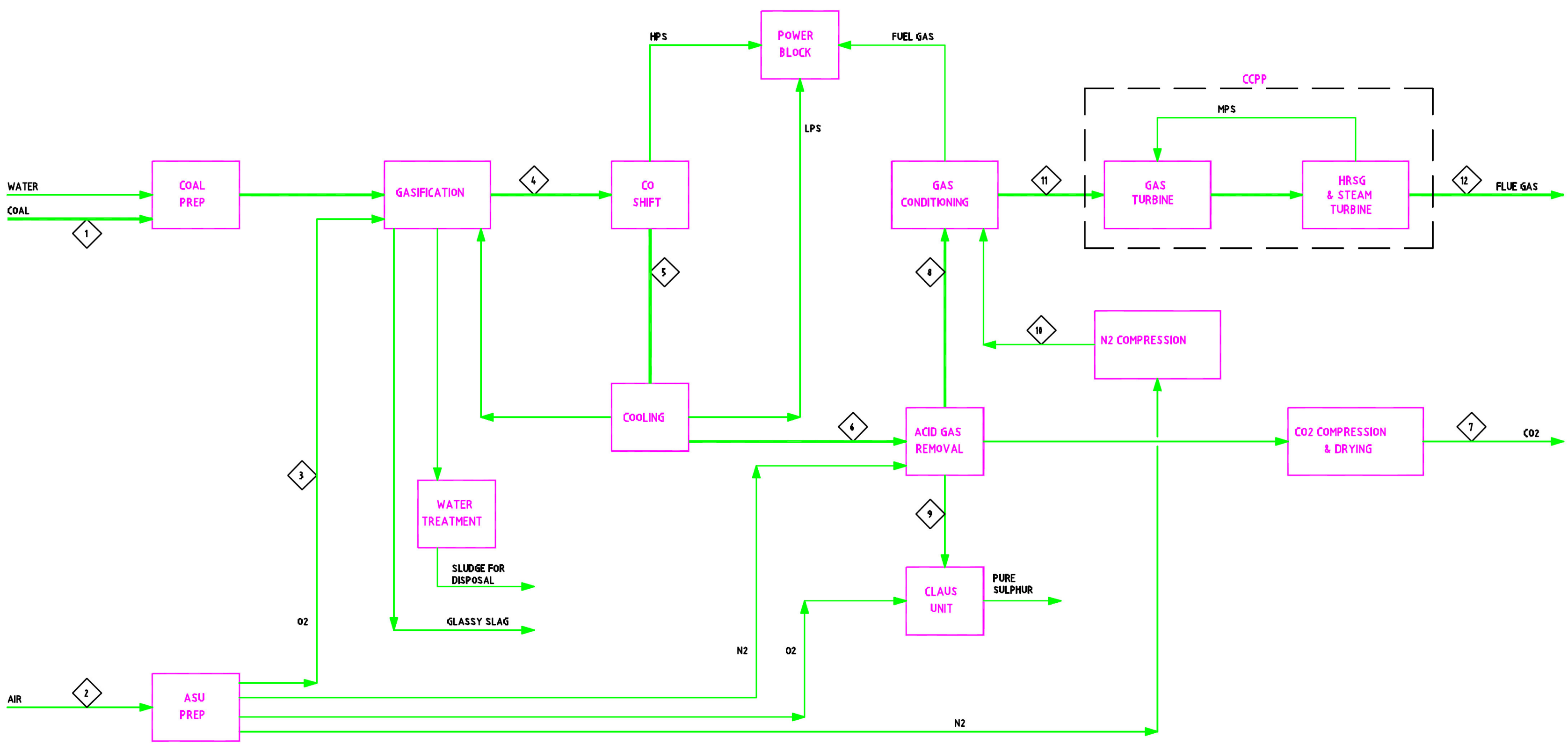

AIR
2
AIR COMPRESSION
HPS
POWER BLOCK
NATURAL GAS
1
DESULPHURISATION
3
AUTO-THERMAL REFORMER
4
HIGH TEMP COOLING
SHIFT
5
COOLING & CONDENSATION
PROCESS WATER
6
ACID GAS REMOVAL
7
GAS COMPRESSION
9
CCPP
GAS TURBINE
HRSG & STEAM TURBINE
MPS
10
FLUE GAS
CO2 COMPRESSION & DRYING
8
CO2

# Case 3-1



HPS
POWER BLOCK
FUEL GAS
LPS
CCPP
WATER
COAL
COAL PREP
GASIFICATION
CO SHIFT
GAS CONDITIONING
GAS TURBINE
HRSG & STEAM TURBINE
FLUE GAS
N2 COMPRESSION
COOLING
ACID GAS REMOVAL
CO2 COMPRESSION & DRYING
CO2
WATER TREATMENT
SLUDGE FOR DISPOSAL
GLASSY SLAG
CLAUS UNIT
PURE SULPHUR
O2
N2
O2
N2
AIR
ASU PREP
1
2
3
4
5
6
7
8
9
10
11
12

# Case 3-2



WATER
COAL
COAL PREP
GASIFICATION
CO SHIFT
POWER BLOCK
HPS
FUEL GAS
LPS
GAS CONDITIONING
CCPP
MPS
GAS TURBINE
HRSG & STEAM TURBINE
FLUE GAS
N2 COMPRESSION
COOLING
ACID GAS REMOVAL
CO2 COMPRESSION & DRYING
CO2
WATER TREATMENT
SLUDGE FOR DISPOSAL
GLASSY SLAG
CLAUS UNIT
PURE SULPHUR
O2
N2
O2
N2
AIR
ASU PREP
1
2
3
4
5
6
7
8
9
10
11
12

# JACOBS ENGINEERING
# MASS BALANCE



Document No.: **60-8389-00/P.03/1000/A4**

Project No.: 60-8389-00 Plant: Reference Gas

Client: IEA GHG Location: N.E.Netherlands

Case: **Case 1**



| STREAM NUMBER | | 1 | | 2 | | 3 | | 4 | | 5 | | 6 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | Fuel Gas | | Gas Turbine Exhaust | | Flue Gas | | CO2 Export | | | | | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Methane | 16.042 | 2335.47 | 83.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Carbon Dioxide | 44.010 | 50.11 | 1.80 | 3354.08 | 4.56 | 501.77 | 0.71 | 2852.31 | 99.42 | | | | |
| Carbon Monoxide | 28.010 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Nitrogen | 28.013 | 11.13 | 0.40 | 59724.97 | 81.21 | 59724.26 | 84.51 | 0.71 | 0.02 | | | | |
| Hydrogen | 2.016 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Ethane | 30.069 | 256.09 | 9.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Propane | 44.096 | 91.86 | 3.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Butane | 58.122 | 38.97 | 1.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Argon | 39.948 | 0.00 | 0.00 | 712.44 | 0.97 | 712.42 | 1.01 | 0.02 | 0.00 | | | | |
| Oxygen | 31.999 | 0.00 | 0.00 | 9750.04 | 13.26 | 9734.23 | 13.77 | 15.80 | 0.55 | | | | |
| Hydrogen Sulphide | 34.082 | 0.01 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Temperature | °C | 10.0 | | 99.4 | | 38.2 | | 40.0 | | | | | |
| Pressure | bar(a) | 41.0 | | 1.0 | | Amb | | 111.0 | | | | | |
| Total Dry Molar Flow | (kg.mol/h) | 2783.65 | 100.00 | 73541.54 | 100.00 | 70672.69 | 100.00 | 2868.84 | 100.00 | | | | |
| Water (kg mol/h) | 18.015 | 0.00 | | 6516.74 | | 5454.07 | | 0.00 | | | | | |
| TOTAL WET | (kg mol/h) | 2783.65 | | 80058.28 | | 76126.76 | | 2868.84 | | | | | |
| Total Mass Flow (kg/h) | | 54000 | | 2278600 | | 2133400 | | 126100 | | | | | |
| Molecular Weight | | 19.40 | | 28.46 | | 28.02 | | 43.94 | | | | | |

Notes :

250 MW Heat Release Case

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Issue: | 0 | Date | 1 | Date | | Date | | Date | | Date |
| Description: | For Final Report | | Temp & Press Added | | | | | | | |
| Made By: | THLW | 04-mei-04 | NJE | 23-jul-04 | | | | | | |
| Checked: | SBJS | 05-mei-04 | SBJS | 26-jul-04 | | | | | | |
| Approved: | SBJS | 05-mei-04 | SBJS | 26-jul-04 | | | | | | |

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/2101/A4**

Project No.: 60-8389-00 Plant: Autothermal Ref.
Client: IEA Location: NE Netherlands
Case: 2-1



| STREAM NUMBER | | 1 | | 2 | | 3 | | 4 | | 5 | | 6 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | Feed Gas | | Air | | Desulphurised Feed Gas | | Reformed Gas | | Shifted Gas | | Dry Shifted Gas | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 0.00 | 0.00 | 0.00 | 0.00 | 66.04 | 1.92 | 6960.91 | 35.28 | 9358.72 | 42.29 | 9358.71 | 42.30 |
| Nitrogen | 28.013 | 13.24 | 0.40 | 8623.06 | 78.09 | 74.71 | 2.17 | 8697.77 | 44.09 | 8697.77 | 39.31 | 8697.76 | 39.31 |
| Carbon Monoxide | 28.010 | 0.00 | 0.00 | 0.00 | 0.00 | 2.73 | 0.08 | 2784.02 | 14.11 | 386.22 | 1.75 | 386.22 | 1.75 |
| Carbon Dioxide | 44.010 | 59.60 | 1.80 | 3.36 | 0.03 | 60.33 | 1.75 | 1023.44 | 5.19 | 3421.26 | 15.46 | 3421.13 | 15.46 |
| Methane | 16.042 | 2778.02 | 83.90 | 0.00 | 0.00 | 2778.65 | 80.70 | 160.06 | 0.81 | 160.06 | 0.72 | 160.06 | 0.72 |
| Ethane | 30.069 | 304.62 | 9.20 | 0.00 | 0.00 | 304.62 | 8.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Propane | 44.096 | 109.27 | 3.30 | 0.00 | 0.00 | 109.27 | 3.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Butane | 58.122 | 46.36 | 1.40 | 0.00 | 0.00 | 46.36 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Argon | 39.948 | 0.00 | 0.00 | 102.67 | 0.93 | 0.57 | 0.02 | 103.23 | 0.52 | 103.23 | 0.47 | 103.23 | 0.47 |
| Oxygen | 31.999 | 0.00 | 0.00 | 2312.91 | 20.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Hydrogen Sulphide | 34.082 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Temperature | °C | 10.0 | | 9.0 | | 379.9 | | 950.0 | | 263.3 | | 50.0 | |
| Pressure | bar(a) | 41.0 | | Ambient | | 37.5 | | 34.4 | | 32.3 | | 30.4 | |
| Total Dry Molar Flow | (kmol/h) | 3311.11 | 100.00 | 11042.00 | 100.00 | 3443.26 | 100.00 | 19729.44 | 100.00 | 22127.26 | 100.00 | 22127.11 | 100.00 |
| Water (kmol/h) | 18.015 | 0.00 | | 77.77 | | 0.28 | | 3903.90 | | 1506.09 | | 92.87 | |
| TOTAL WET | (kmol/h) | 3311.11 | | 11119.77 | | 3443.55 | | 23633.33 | | 23633.35 | | 22219.99 | |
| Total Mass Flow (kg/h) | | 64200 | | 321000 | | 66200 | | 458000 | | 458000 | | 432000 | |
| Molecular Weight | | 19.40 | | 28.89 | | 19.23 | | 19.37 | | 19.37 | | 19.45 | |

Notes : All flows are for a single stream

| | Issue: | 0 | Date | 1 | Date | | Date | | Date | | Date |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Description: | For Final Report | | Temp & Press Added | | | | | | | |
| | Made By: | THLW | 05-apr-04 | NJE | 16-jul-04 | | | | | | |
| | Checked: | SBJS | 06-apr-04 | SBJS | 26-jul-04 | | | | | | |
| | Approved: | SBJS | 06-apr-04 | SBJS | 26-jul-04 | | | | | | |

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/2101/A4**

Project No.: 60-8389-00 Plant: Autothermal Ref.

Client: IEA Location: NE Netherlands

Case: 2-1



| STREAM NUMBER | | 7 | | 8 | | 9 | | 10 | | | | 1 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | CO2 Lean Fuel Gas | | Compressed CO2 | | Conditioned Fuel Gas | | Flue Gas | | | | | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 9257.52 | 49.97 | 35.15 | 1.01 | 9257.51 | 49.97 | 0.00 | 0.00 | | | | |
| Nitrogen | 28.013 | 8615.27 | 46.51 | 21.02 | 0.61 | 8615.27 | 46.51 | 60371.02 | 85.56 | | | | |
| Carbon Monoxide | 28.010 | 382.24 | 2.06 | 1.25 | 0.04 | 382.24 | 2.06 | 0.00 | 0.00 | | | | |
| Carbon Dioxide | 44.010 | 101.97 | 0.55 | 3317.26 | 95.63 | 101.97 | 0.55 | 591.45 | 0.84 | | | | |
| Methane | 16.042 | 88.83 | 0.48 | 70.60 | 2.04 | 88.83 | 0.48 | 0.00 | 0.00 | | | | |
| Ethane | 30.069 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Propane | 44.096 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Butane | 58.122 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Argon | 39.948 | 79.26 | 0.43 | 23.40 | 0.67 | 79.26 | 0.43 | 697.73 | 0.99 | | | | |
| Oxygen | 31.999 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 8896.61 | 12.61 | | | | |
| Hydrogen Sulphide | 34.082 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Temperature | °C | 41.1 | | 40.0 | | 230.0 | | 103.8 | | | | | |
| Pressure | bara | 30.0 | | 111.0 | | 28.7 | | Ambient | | | | | |
| Total Dry Molar Flow | (kmol/h) | 18525.09 | 100.00 | 3468.69 | 100.00 | 18525.08 | 100.00 | 70556.80 | 100.00 | | | | |
| Water (kmol/h) | 18.015 | 39.86 | | 0.00 | | 2399.97 | | 12276.32 | | | | | |
| TOTAL WET | (kmol/h) | 18564.96 | | 3468.69 | | 20925.05 | | 82833.12 | | | | | |
| Total Mass Flow (kg/h) | | 281000 | | 149000 | | 323000 | | 2251000 | | | | | |
| Molecular Weight | | 15.11 | | 42.88 | | 15.44 | | 27.17 | | | | | |

Notes : All flows are for a single stream

| Issue: | 0 | Date | 1 | Date | | Date | | Date | | Date |
|---|---|---|---|---|---|---|---|---|---|---|
| Description: | For Final Report | | Temp & Press Added | | | | | | | |
| Made By: | THLW | 05-apr-04 | NJE | 16-jul-04 | | | | | | |
| Checked: | SBJS | 06-apr-04 | SBJS | 26-jul-04 | | | | | | |
| Approved: | SBJS | 06-apr-04 | SBJS | 26-jul-04 | | | | | | |

**JACOBS CONSULTANCY**

# JACOBS CONSULTANCY UK LTD
# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/2201/A4**

Project No.: 60-8389-00 Plant: Autothermal Ref.
Client: IEA Location: NE Netherlands
Case: 2-2



| STREAM NUMBER | | 1 | | 2 | | 3 | | 4 | | 5 | | 6 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | Feed Gas | | Air | | Desulphurised Feed Gas | | Reformed Gas | | Shifted Gas | | Dry Shifted Gas | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 0.00 | 0.00 | 0.00 | 0.00 | 65.99 | 1.92 | 6985.31 | 35.32 | 9389.36 | 42.34 | 9389.35 | 42.34 |
| Nitrogen | 28.013 | 13.23 | 0.40 | 8646.79 | 78.09 | 74.64 | 2.17 | 8721.44 | 44.10 | 8721.44 | 39.32 | 8721.43 | 39.32 |
| Carbon Monoxide | 28.010 | 0.00 | 0.00 | 0.00 | 0.00 | 2.72 | 0.08 | 2796.01 | 14.14 | 391.96 | 1.77 | 391.96 | 1.77 |
| Carbon Dioxide | 44.010 | 59.55 | 1.80 | 3.37 | 0.03 | 60.28 | 1.75 | 1023.57 | 5.18 | 3427.63 | 15.45 | 3427.50 | 15.45 |
| Methane | 16.042 | 2775.71 | 83.90 | 0.00 | 0.00 | 2776.34 | 80.70 | 144.66 | 0.73 | 144.66 | 0.65 | 144.66 | 0.65 |
| Ethane | 30.069 | 304.37 | 9.20 | 0.00 | 0.00 | 304.37 | 8.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Propane | 44.096 | 109.18 | 3.30 | 0.00 | 0.00 | 109.18 | 3.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Butane | 58.122 | 46.32 | 1.40 | 0.00 | 0.00 | 46.32 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Argon | 39.948 | 0.00 | 0.00 | 102.95 | 0.93 | 0.56 | 0.02 | 103.52 | 0.52 | 103.52 | 0.47 | 103.52 | 0.47 |
| Oxygen | 31.999 | 0.00 | 0.00 | 2319.28 | 20.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Hydrogen Sulphide | 34.082 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Temperature | °C | 10.0 | | 9.0 | | 379.9 | | 950.0 | | 263.3 | | 50.0 | |
| Pressure | bar(a) | 41.0 | | Ambient | | 37.5 | | 34.4 | | 32.3 | | 31.3 | |
| Total Dry Molar Flow | (kmol/h) | 3308.36 | 100.00 | 11072.39 | 100.00 | 3440.40 | 100.00 | 19774.50 | 100.00 | 22178.56 | 100.00 | 22178.41 | 100.00 |
| Water (kmol/h) | 18.015 | 0.00 | | 77.98 | | 0.28 | | 3901.28 | | 1497.22 | | 89.33 | |
| TOTAL WET | (kmol/h) | 3308.36 | | 11150.37 | | 3440.68 | | 23675.77 | | 23675.79 | | 22267.74 | |
| Total Mass Flow (kg/h) | | 64200 | | 322000 | | 66200 | | 458000 | | 459000 | | 433000 | |
| Molecular Weight | | 19.40 | | 28.89 | | 19.23 | | 19.37 | | 19.37 | | 19.45 | |

Notes : All flows are for a single stream

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Issue: | 0 | Date | 1 | Date | | Date | | Date | | Date |
| Description: | For Final Report | | Revised T & P | | | | | | | |
| Made By: | THLW | 05-apr-04 | NJE | 23-jul-04 | | | | | | |
| Checked: | SBJS | 28-apr-04 | SBJS | 26-jul-04 | | | | | | |
| Approved: | SBJS | 28-apr-04 | SBJS | 26-jul-04 | | | | | | |

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/2201/A4**

Project No.: 60-8389-00 Plant: Autothermal Ref.
Client: IEA Location: NE Netherlands
Case: 2-2



| STREAM NUMBER | | 7 | | 8 | | 9 | | 10 | | 11 | | 12 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | CO2 Lean Fuel Gas | | Compressed CO2 | | Conditioned Fuel Gas | | Flue Gas | | | | | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 9286.73 | 50.01 | 36.58 | 1.05 | 9286.73 | 50.01 | 0.00 | 0.00 | | | | |
| Nitrogen | 28.013 | 8638.13 | 46.51 | 21.87 | 0.63 | 8638.13 | 46.51 | 60476.54 | 85.57 | | | | |
| Carbon Monoxide | 28.010 | 387.88 | 2.09 | 1.32 | 0.04 | 387.88 | 2.09 | 0.00 | 0.00 | | | | |
| Carbon Dioxide | 44.010 | 102.15 | 0.55 | 3327.08 | 95.68 | 102.15 | 0.55 | 589.08 | 0.83 | | | | |
| Methane | 16.042 | 77.86 | 0.42 | 66.25 | 1.91 | 77.86 | 0.42 | 0.00 | 0.00 | | | | |
| Ethane | 30.069 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Propane | 44.096 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Butane | 58.122 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| Argon | 39.948 | 78.59 | 0.42 | 24.37 | 0.70 | 78.59 | 0.42 | 696.94 | 0.99 | | | | |
| Oxygen | 31.999 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 8910.93 | 12.61 | | | | |
| Hydrogen Sulphide | 34.082 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Temperature | °C | 41.4 | | 40.0 | | 22.0 | | 103.0 | | | | | |
| Pressure | bar(a) | 31.2 | | 111.0 | | 39.9 | | Ambient | | | | | |
| Total Dry Molar Flow | (kmol/h) | 18571.33 | 100.00 | 3477.48 | 100.00 | 18571.33 | 100.00 | 70673.50 | 100.00 | | | | |
| Water (kmol/h) | 18.015 | 38.42 | | 0.00 | | 0.00 | | 12296.09 | | | | | |
| TOTAL WET | (kmol/h) | 18609.75 | | 3477.48 | | 18571.33 | | 82969.60 | | | | | |
| Total Mass Flow (kg/h) | | 281000 | | 149000 | | 280000 | | 2255000 | | | | | |
| Molecular Weight | | 15.11 | | 42.90 | | 15.10 | | 27.17 | | | | | |

Notes : All flows are for a single stream

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Issue: | 0 | Date | 1 | Date | | Date | | Date | | Date |
| Description: | For Final Report | | Revised T & P | | | | | | | |
| Made By: | THLW | 05-apr-04 | NJE | 23-jul-04 | | | | | | |
| Checked: | SBJS | 28-apr-04 | SBJS | 26-jul-04 | | | | | | |
| Approved: | SBJS | 28-apr-04 | SBJS | 26-jul-04 | | | | | | |

**JACOBS CONSULTANCY**

# JACOBS CONSULTANCY UK LTD

# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/3101/A4**

Project No.: 60-8389-00 Plant: Capture Plant

Client: IEA GHG Location: NE Netherlands

Case: 3-1 Coal based GEM local to CCU



| STREAM NUMBER | | 1 | | 2 | | 3 | | 4 | | 5 | | 6 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | Coal Feed | | ASU Air Intake | | Oxygen for Gasifier | | Raw Syngas | | Shifted Syngas | | Cold Syngas | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 10037.03 | 55.20 | 10029.61 | 55.41 |
| Nitrogen | 28.013 | 0.00 | 0.00 | 13580.48 | 78.10 | 75.19 | 2.00 | [redacted] | [redacted] | 142.99 | 0.79 | 142.87 | 0.79 |
| Carbon Monoxide | 28.010 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 822.31 | 4.52 | 821.74 | 4.54 |
| Carbon Dioxide | 44.010 | 0.00 | 0.00 | 3.34 | 0.02 | 0.00 | 0.00 | [redacted] | [redacted] | 6993.55 | 38.46 | 6940.77 | 38.34 |
| Methane | 16.042 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 13.89 | 0.08 | 13.85 | 0.08 |
| Argon | 39.948 | 0.00 | 0.00 | 161.69 | 0.93 | 112.78 | 3.00 | [redacted] | [redacted] | 113.08 | 0.62 | 112.75 | 0.62 |
| Hydrogen Sulphide | 34.082 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 41.10 | 0.23 | 39.34 | 0.22 |
| Carbonyl Sulphide | 60.076 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 0.14 | 0.00 | 0.14 | 0.00 |
| Ammonia | 17.031 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 20.06 | 0.11 | 0.00 | 0.00 |
| Oxygen | 31.999 | 0.00 | 0.00 | 3644.18 | 20.96 | 3571.30 | 95.00 | [redacted] | [redacted] | 0.00 | 0.00 | 0.00 | 0.00 |
| Sulphur Dioxide | 64.065 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | | | | | | [redacted] | [redacted] | | | | |
| | | | | | | | | [redacted] | [redacted] | | | | |
| Coal | (kg/hr) | 133567.55 | | | | | | [redacted] | [redacted] | | | | |
| Temperature | °C | ambient | | ambient | | 149.0 | | [redacted] | [redacted] | 440.0 | | 30.8 | |
| Pressure | bara | ambient | | ambient | | 79.9 | | [redacted] | [redacted] | 60.7 | | 59.2 | |
| Total Dry Molar Flow | (kmol/h) | 0.00 | 0.00 | 17389.69 | 100.00 | 3759.26 | 100.00 | 0.00 | 0.00 | 18184.16 | 100.00 | 18101.06 | 100.00 |
| Water (kmol/h) | 18.015 | 778.29 | | 121.55 | | 0.00 | | 25226.77 | | 19919.65 | | 14.79 | |
| TOTAL WET | (kmol/h) | 778.29 | | 17511.24 | | 3759.26 | | 25226.77 | | 38103.81 | | 18115.85 | |
| Total Mass Flow (kg/h) | | 148000 | | 506000 | | 121000 | | 454000 | | 720000 | | 359000 | |
| Molecular Weight | | N/A | | 28.89 | | 32.16 | | 18.02 | | 18.91 | | 19.82 | |

Notes : All flows are for a single stream

| | 0 | Date | 1 | Date | | Date | | Date | | Date |
|---|---|---|---|---|---|---|---|---|---|---|
| Issue: | 0 | Date | 1 | Date | | Date | | Date | | Date |
| Description: | For Final Report | | Revised | | | | | | | |
| Made By: | THLW | 05-apr-04 | NJE | 15-jul-04 | | | | | | |
| Checked: | SBJS | 06-apr-04 | SBJS | 23-jul-04 | | | | | | |
| Approved: | SBJS | 06-apr-04 | SBJS | 23-jul-04 | | | | | | |

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/3101/A4**

Project No.: 60-8389-00 Plant: Capture Plant

Client: IEA GHG Location: NE Netherlands

Case: 3-1 Coal based GEM local to CCU



| STREAM NUMBER | | 7 | | 8 | | 9 | | 10 | | 11 | | 12 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | CO2 for capture | | Sweet Syngas | | H2S Rich Gas to Claus Unit | | Dilution Nitrogen | | Fuel Gas | | Flue Gas | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 134.90 | 1.98 | 9906.08 | 74.63 | 0.00 | 0.00 | 0.00 | 0.00 | 9019.89 | 65.07 | 0.00 | 0.00 |
| Nitrogen | 28.013 | 16.63 | 0.24 | 2148.79 | 16.19 | 57.38 | 35.36 | 7628.23 | 100.00 | 3731.32 | 26.92 | 61929.78 | 85.61 |
| Carbon Monoxide | 28.010 | 28.40 | 0.42 | 793.34 | 5.98 | 0.00 | 0.00 | 0.00 | 0.00 | 722.37 | 5.21 | 0.00 | 0.00 |
| Carbon Dioxide | 44.010 | 6637.51 | 97.30 | 303.27 | 2.28 | 63.77 | 39.29 | 0.00 | 0.00 | 276.14 | 1.99 | 1031.21 | 1.43 |
| Methane | 16.042 | 0.99 | 0.01 | 12.86 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 11.71 | 0.08 | 0.00 | 0.00 |
| Argon | 39.948 | 3.49 | 0.05 | 109.70 | 0.83 | 0.00 | 0.00 | 0.00 | 0.00 | 99.89 | 0.72 | 703.84 | 0.97 |
| Hydrogen Sulphide | 34.082 | 0.00 | 0.00 | 0.05 | 0.00 | 41.05 | 25.30 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 |
| Carbonyl Sulphide | 60.076 | 0.00 | 0.00 | 0.05 | 0.00 | 0.09 | 0.06 | 0.00 | 0.00 | 0.05 | 0.00 | 0.00 | 0.00 |
| Ammonia | 17.031 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Oxygen | 31.999 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 8675.24 | 11.99 |
| Sulphur Dioxide | 64.065 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Temperature | °C | 40.0 | | 33.2 | | 70.0 | | 230.0 | | 230.0 | | 101.3 | |
| Pressure | bara | 111.0 | | 59.2 | | 1.7 | | 24.5 | | 28.9 | | ambient | |
| Total Dry Molar Flow | (kmol/h) | 6821.93 | 100.00 | 13274.13 | 100.00 | 162.29 | 100.00 | 7628.23 | 100.00 | 13861.41 | 100.00 | 72340.16 | 100.0 |
| Water (kmol/h) | 18.015 | 0.00 | | 16.63 | | 17.84 | | 0.00 | | 12.45 | | 9501.85 | |
| TOTAL WET | (kmol/h) | 6821.93 | | 13290.76 | | 180.13 | | 7628.23 | | 13873.86 | | 81842.00 | |
| Total Mass Flow (kg/h) | | 294000 | | 121000 | | 6140 | | 214000 | | 160000 | | 2257000 | |
| Molecular Weight | | 43.07 | | 9.08 | | 34.08 | | 28.01 | | 11.50 | | 27.58 | |

Notes : All flows are for a single stream

| | Issue: | 0 | Date | 1 | Date | | Date | | Date | | Date |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Description: | For Final Report | | Revised | | | | | | | |
| | Made By: | THLW | 05-apr-04 | NJE | 15-jul-04 | | | | | | |
| | Checked: | SBJS | 06-apr-04 | SBJS | 23-jul-04 | | | | | | |
| | Approved: | SBJS | 06-apr-04 | SBJS | 23-jul-04 | | | | | | |

**JACOBS CONSULTANCY**

# JACOBS CONSULTANCY UK LTD

# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/3201/A4**

Project No.: 60-8389-00 Plant: Capture Plant

Client: IEA GHG Location: NE Netherlands

Case: 3-2 Coal fed GEM remote from CCPP



| STREAM NUMBER | | 1 | | 2 | | 3 | | 4 | | 5 | | 6 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | Coal Feed | | ASU Air Intake | | Oxygen for Gasifier | | Raw Syngas | | Shifted Syngas | | Cold Syngas | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 11194.96 | 55.26 | 11186.68 | 55.41 |
| Nitrogen | 28.013 | 0.00 | 0.00 | 15147.19 | 78.10 | 83.86 | 2.00 | [redacted] | [redacted] | 159.49 | 0.79 | 159.36 | 0.79 |
| Carbon Monoxide | 28.010 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 917.18 | 4.53 | 916.54 | 4.54 |
| Carbon Dioxide | 44.010 | 0.00 | 0.00 | 3.72 | 0.02 | 0.00 | 0.00 | [redacted] | [redacted] | 7800.36 | 38.50 | 7741.49 | 38.34 |
| Methane | 16.042 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 15.49 | 0.08 | 15.45 | 0.08 |
| Argon | 39.948 | 0.00 | 0.00 | 180.35 | 0.93 | 125.79 | 3.00 | [redacted] | [redacted] | 126.13 | 0.62 | 125.75 | 0.62 |
| Hydrogen Sulphide | 34.082 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 45.84 | 0.23 | 43.88 | 0.22 |
| Carbonyl Sulphide | 60.076 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 0.15 | 0.00 | 0.15 | 0.00 |
| Ammonia | 17.031 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 0.00 | 0.00 | 0.00 | 0.00 |
| Oxygen | 31.999 | 0.00 | 0.00 | 4064.59 | 20.96 | 3983.30 | 95.00 | [redacted] | [redacted] | 0.00 | 0.00 | 0.00 | 0.00 |
| Sulphur Dioxide | 64.065 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | [redacted] | [redacted] | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | | | | | | [redacted] | [redacted] | | | | |
| Coal | (kg/hr) | 148976.60 | | | | | | [redacted] | [redacted] | | | | |
| | | | | | | | | [redacted] | [redacted] | | | | |
| Temperature | °C | ambient | | ambient | | 149.0 | | [redacted] | [redacted] | 440.0 | | 27.1 | |
| Pressure | bara | ambient | | ambient | | 79.9 | | [redacted] | [redacted] | 60.7 | | 59.2 | |
| Total Dry Molar Flow | (kmol/h) | 0.00 | 0.00 | 19395.86 | 100.00 | 4192.95 | 100.00 | 0.00 | 0.00 | 20259.60 | 100.00 | 20189.30 | 100.00 |
| Water (kmol/h) | 18.015 | 868.08 | | 135.58 | | 0.00 | | 28128.08 | | 22.38 | | 0.00 | |
| TOTAL WET | (kmol/h) | 868.08 | | 19531.43 | | 4192.95 | | 28128.08 | | 20281.98 | | 20189.30 | |
| Total Mass Flow (kg/h) | | 165000 | | 564000 | | 135000 | | 507000 | | 403000 | | 400000 | |
| Molecular Weight | | N/A | | 28.89 | | 32.16 | | 18.02 | | 19.88 | | 19.82 | |

Notes : All flows are for a single stream

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Issue: | 0 | Date | 1 | Date | 2 | Date | | Date | | Date |
| Description: | For Final Report | | CO2 stream added | | Revised | | | | | |
| Made By: | THLW | 05-apr-04 | THLW | 05-mei-04 | NJE | 16-jul-04 | | | | |
| Checked: | SBJS | 28-apr-04 | SBJS | 05-mei-04 | SBJS | 22-jul-04 | | | | |
| Approved: | SBJS | 28-apr-04 | SBJS | 05-mei-04 | SBJS | 22-jul-04 | | | | |

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

# MATERIAL BALANCE



Document No.: **60-8389-00/P.03/3201/A4**

Project No.: 60-8389-00 | Plant: Capture Plant
Client: IEA GHG | Location: NE Netherlands
Case: 3-2 Coal fed GEM remote from CCPP



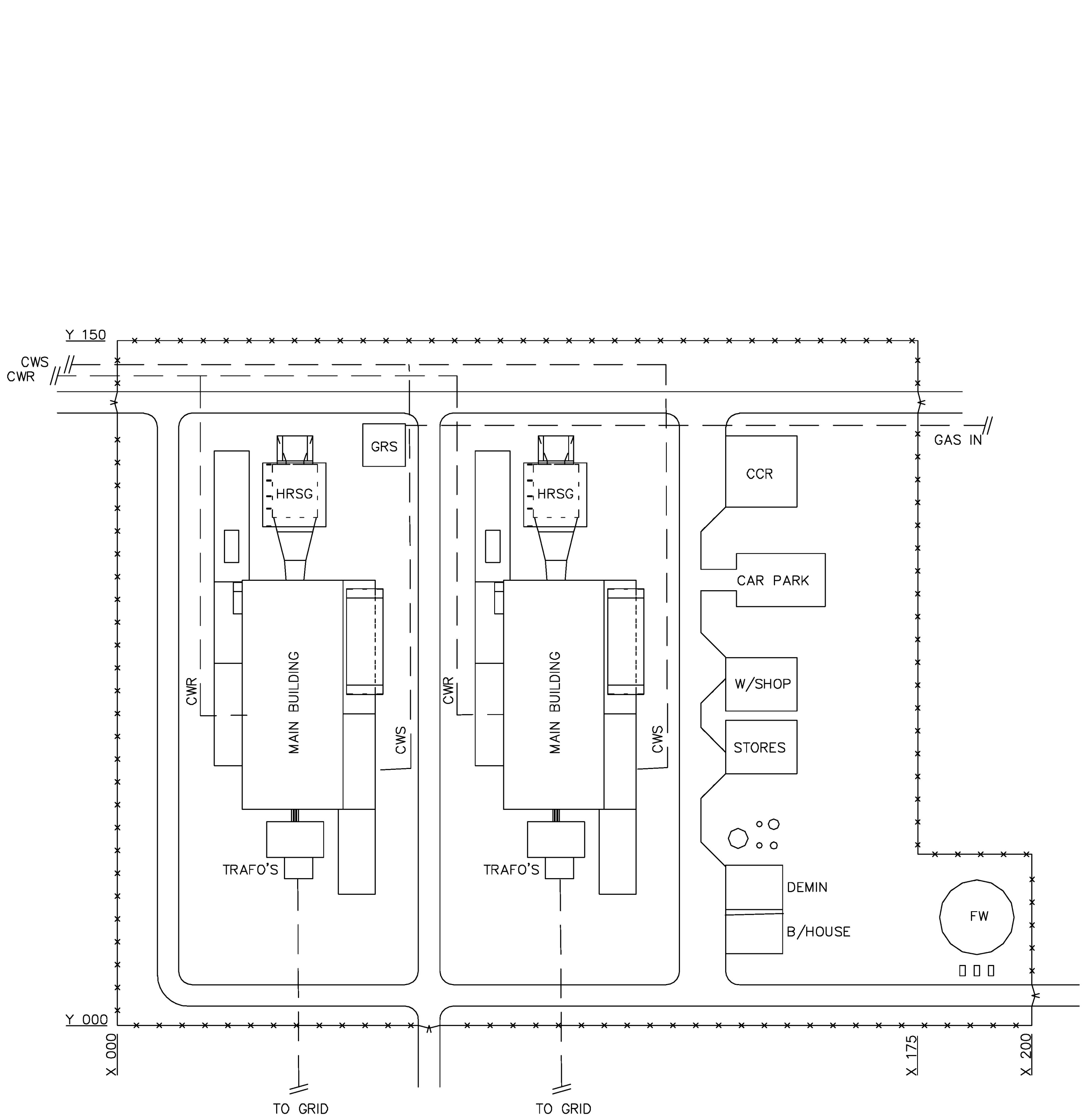
| STREAM NUMBER | | 7 | | 8 | | 9 | | 10 | | 11 | | 12 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STREAM NAME | | CO2 for export | | Sweet Syngas | | H2S Rich Gas to Claus Unit | | Dilution Nitrogen | | Fuel Gas | | Flue Gas | |
| COMPONENT | MW | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) | kmol/h | mol% (dry) |
| Hydrogen | 2.016 | 150.46 | 1.98 | 11048.48 | 74.62 | 0.00 | 0.00 | 0.00 | 0.00 | 9095.22 | 46.01 | 0.00 | 0.00 |
| Nitrogen | 28.013 | 18.55 | 0.24 | 2396.69 | 16.19 | 64.00 | 35.36 | 9210.14 | 100.00 | 9554.86 | 48.33 | 60961.72 | 85.17 |
| Carbon Monoxide | 28.010 | 31.69 | 0.42 | 885.26 | 5.98 | 0.00 | 0.00 | 0.00 | 0.00 | 728.75 | 3.69 | 0.00 | 0.00 |
| Carbon Dioxide | 44.010 | 7402.87 | 97.30 | 338.23 | 2.28 | 71.12 | 39.29 | 0.00 | 0.00 | 278.44 | 1.41 | 1037.30 | 1.45 |
| Methane | 16.042 | 1.10 | 0.01 | 14.35 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 11.81 | 0.06 | 0.00 | 0.00 |
| Argon | 39.948 | 3.89 | 0.05 | 122.35 | 0.83 | 0.00 | 0.00 | 0.00 | 0.00 | 100.72 | 0.51 | 716.23 | 1.00 |
| Hydrogen Sulphide | 34.082 | 0.00 | 0.00 | 0.05 | 0.00 | 45.79 | 25.30 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 |
| Carbonyl Sulphide | 60.076 | 0.00 | 0.00 | 0.06 | 0.00 | 0.10 | 0.06 | 0.00 | 0.00 | 0.05 | 0.00 | 0.00 | 0.00 |
| Ammonia | 17.031 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Oxygen | 31.999 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 8858.18 | 12.38 |
| Sulphur Dioxide | 64.065 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| Temperature | °C | 40.0 | | 33.2 | | 70.0 | | 22.0 | | 27.0 | | 103.0 | |
| Pressure | bara | 111.0 | | 59.2 | | 1.7 | | 61.0 | | 59.2 | | ambient | |
| Total Dry Molar Flow | (kmol/h) | 7608.56 | 100.00 | 14805.47 | 100.00 | 181.01 | 100.00 | 9210.14 | 100.00 | 19769.89 | 100.00 | 71573.51 | 100.00 |
| Water (kmol/h) | 18.015 | 0.00 | | 17.84 | | 19.14 | | 0.00 | | 0.00 | | 10751.65 | |
| TOTAL WET | (kmol/h) | 7608.56 | | 14823.31 | | 200.15 | | 9210.14 | | 19769.89 | | 82325.16 | |
| Total Mass Flow (kg/h) | | 328000 | | 135000 | | 6830 | | 258000 | | 323000 | | 2259000 | |
| Molecular Weight | | 43.07 | | 9.08 | | 34.15 | | 28.01 | | 16.33 | | 27.44 | |

Notes : All flows are for a single stream

| Issue: | 0 | Date | 1 | Date | 2 | Date | | Date | | Date |
|---|---|---|---|---|---|---|---|---|---|---|
| Description: | For Final Report | | CO2 stream added | | Revised | | | | | |
| Made By: | THLW | 05-apr-04 | THLW | 05-mei-04 | NJE | 16-jul-04 | | | | |
| Checked: | SBJS | 28-apr-04 | SBJS | 05-mei-04 | SBJS | 22-jul-04 | | | | |
| Approved: | SBJS | 28-apr-04 | SBJS | 05-mei-04 | SBJS | 22-jul-04 | | | | |

# Appendix 3

Plot Lay-outs




## GENERAL NOTES

## REFERENCE DRAWINGS

## EQUIPMENT LISTING

## LEGEND

HRSG –HEAT RECOVERY STEAM GENERATOR
CCR –CENTRAL CONTROL ROOM
DEMIN –DEMINERALIZED WATER TREATMENT PLANT
B/HOUSE –BOILER HOUSE
FW –FIREWATER STORAGE
CWS –COOLING WATER SUPPLY
CWR –COOLING WATER RETURN
GRS –GAS RECEIVING STATION

0 10 20 30 40 50

| No Issue | Date | Description | Made by | Checked by | Disc. apprd by | Proj. apprd by | Client apprd by |
|---|---|---|---|---|---|---|---|
| A | 05-05-2004 | ORIGINAL ISSUE/FOR STUDY | WEA | VLR | KOMI | . | . |



Client/Project Name
IEA GHG
RETROFIT OF CO2 CAPTURE TO NATURAL GAS CCPP

Title
PRELIMINARY OVERALL PLANT LAY-OUT
STANDARD COMBINED CYCLE POWER PLANT

JACOBS

Drawing Number 64114-00-L-01-0001

Drawn by WEA | Date 05-2004 | Drawing Scale 1:50 | Drawing Size A1 | Sheet 1 of 1 | Issue A

Last saved as : P:\P64114\WORK_FILE\CA033_EPU\Reports\Appendices\Appendix3\64114-00-L-01-0001 rev A komi.dwg Date: '2004-05-
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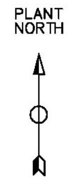
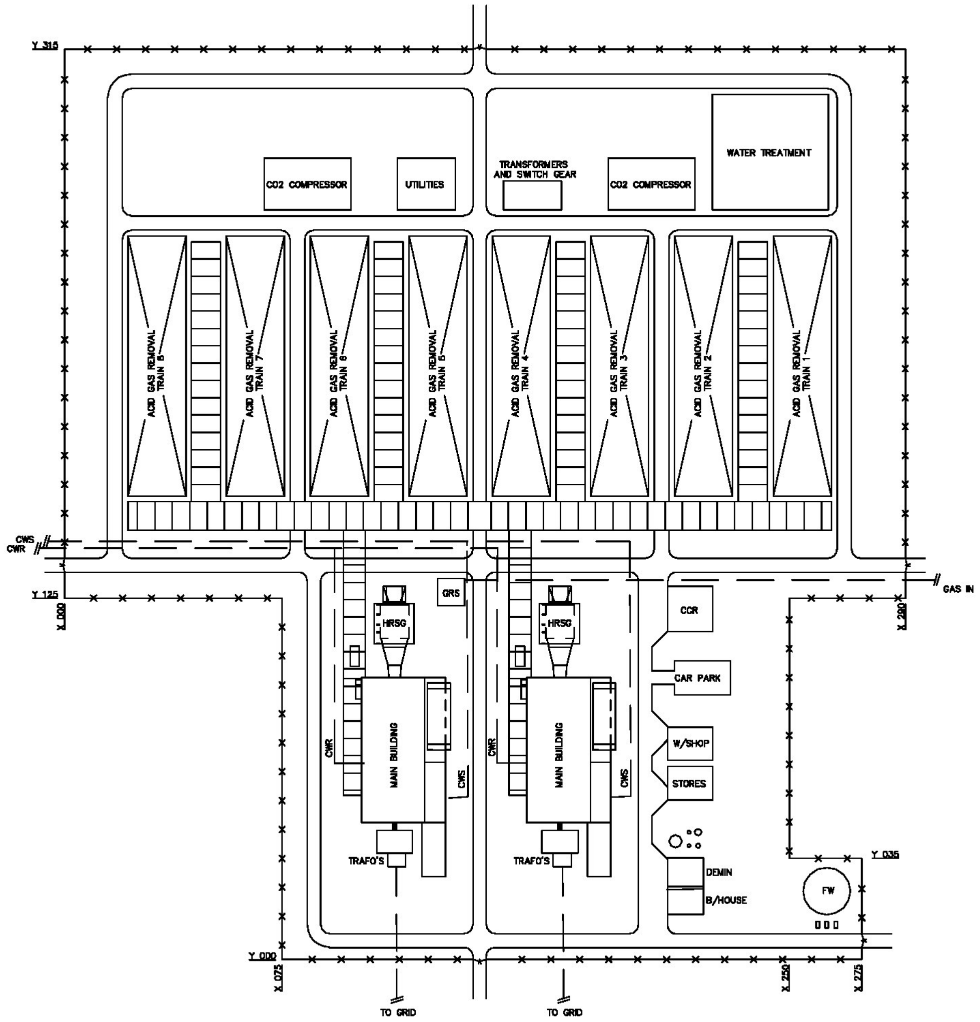



## GENERAL NOTES

## REFERENCE DRAWINGS

## EQUIPMENT LISTING

## LEGEND

HRSG –HEAT RECOVERY STEAM GENERATOR
CCR –CENTRAL CONTROL ROOM
DEMIN –DEMINERALIZED WATER TREATMENT PLANT
B/HOUSE –BOILER HOUSE
FW –FIREWATER STORAGE
CWS –COOLING WATER SUPPLY
CWR –COOLING WATER RETURN
GRS –GAS RECEIVING STATION

0 20 40 60 80 100

| No | Date Issue | Description | Made by | Checked by | Disc. apprd by | Proj. apprd by | Client apprd by |
|---|---|---|---|---|---|---|---|
| A | 05-05-2004 | ORIGINAL ISSUE/FOR STUDY | WEA | VLR | KOMI | . | . |



Client/Project Name

IEA GHG
RETROFIT OF CO2 CAPTURE TO NATURAL GAS CCPP

Title

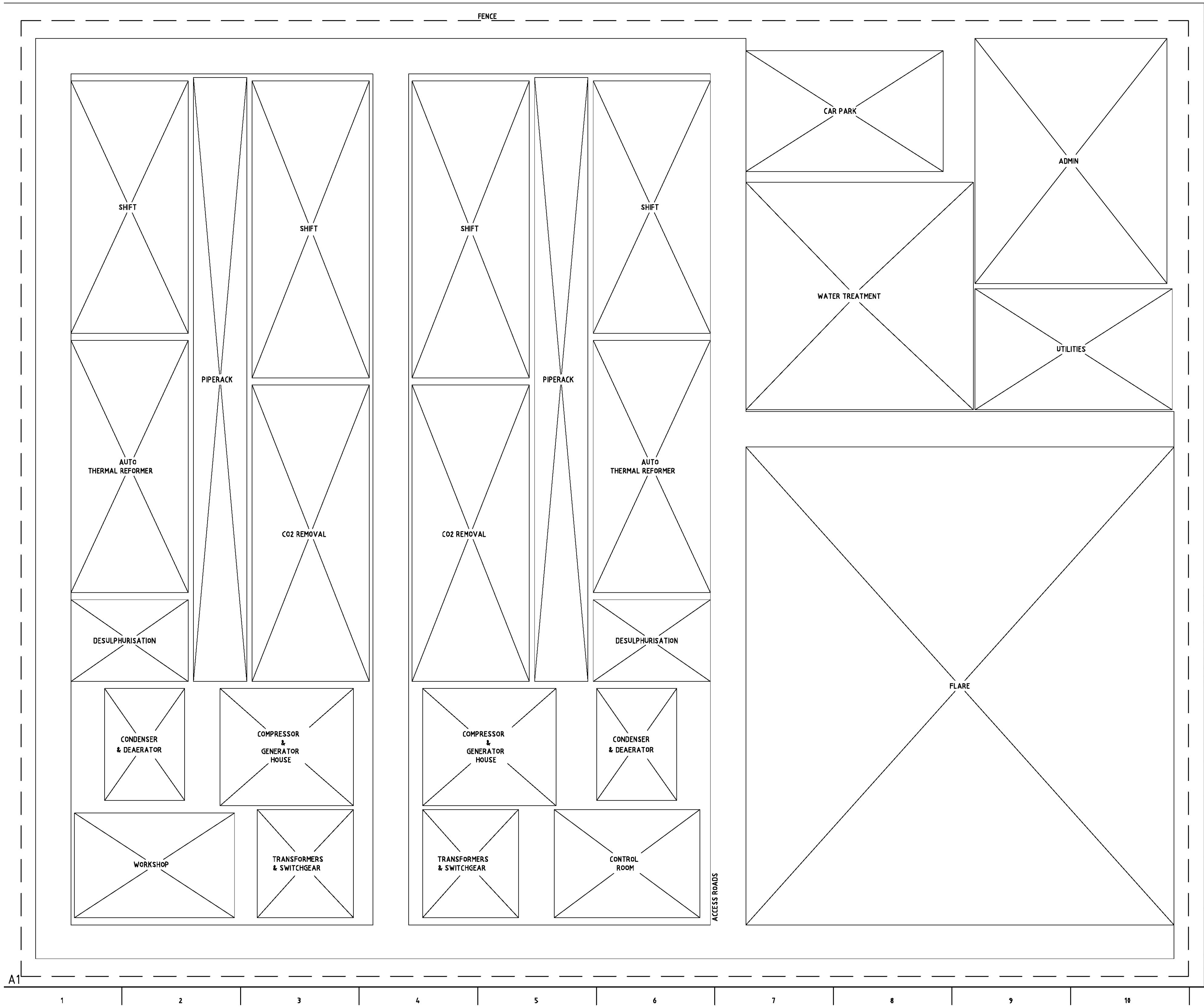
PRELIMINARY OVERALL PLANT LAY-OUT
CASE1 POST COMBUSTION CO2 CAPTURE

JACOBS

Drawing Number 64114-00-L-01-0002

Drawn by WEA | Date 05-2004 | Drawing Scale 1:100 | Drawing Size A1 | Sheet 1 of 1 | Issue A

Last saved as : P:\P64114\COMMON_FILE\64114-00-L-01-0002 rev A KOMI.dwg Date: 2004-05-05 14:40 Version: AutoCAD 15.06




NOTES

10m

| REV. No. | REVISION DESCRIPTION | DRAWN | CHK | JE APP | DATE |
|---|---|---|---|---|---|
| A | FOR FINAL REPORT | | | | |

| CLIENT DRAWING NO. | CLIENT APP. | DATE. |
|---|---|---|
| | | |



JACOBS ENGINEERING UK LTD
PROJECT OFFICE:-
JACOBS HOUSE
427 LONDON ROAD
READING
BERKSHIRE RG6 1BL

A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.

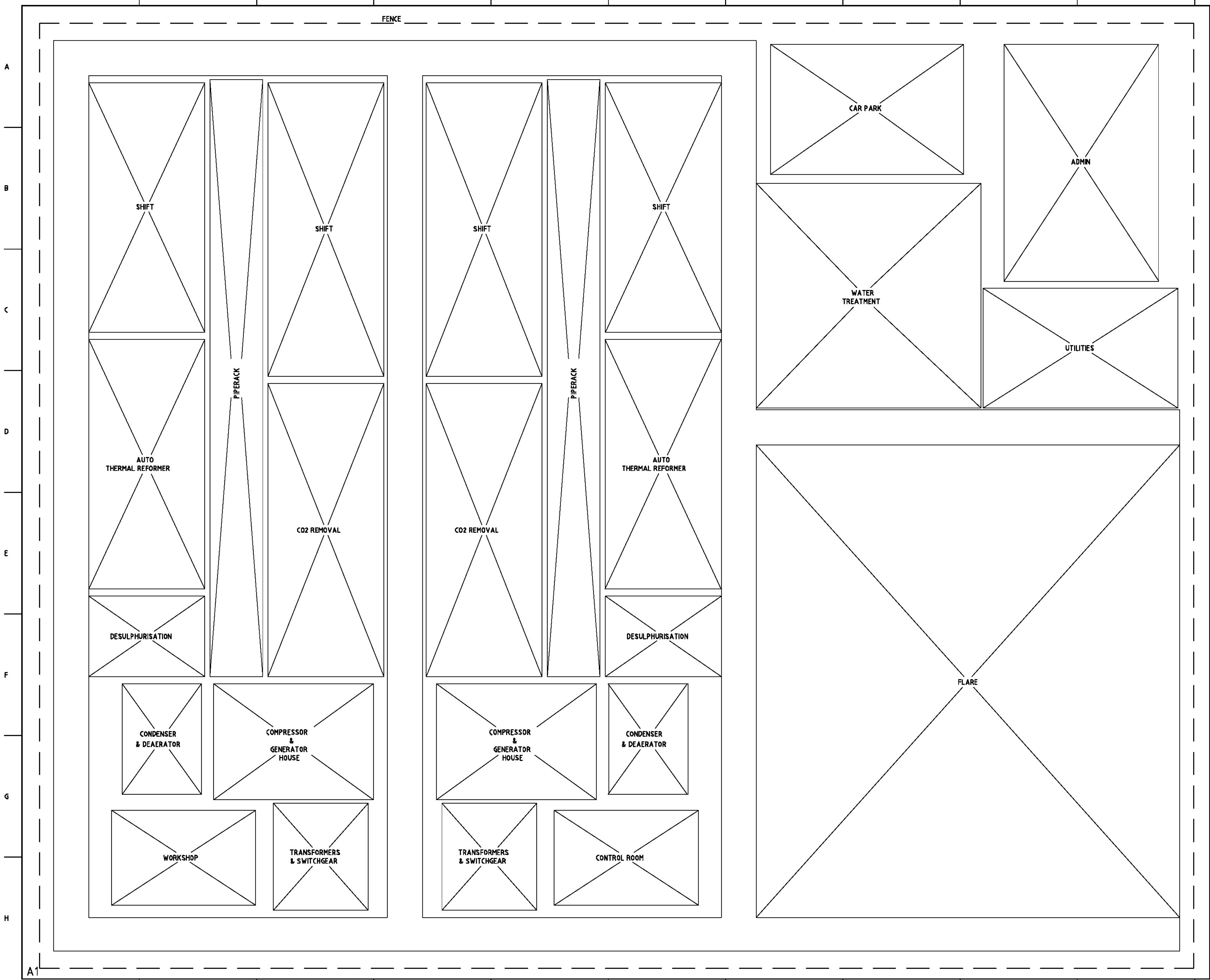
PLANT CO2 CAPTURE PLANT
CLIENT IEA GHG
LOCATION N.E. NETHERLANDS

**PRELIMINARY PLANT LAYOUT**
**CASE 2-1**

DRAWING SCALE NTS | ORIGINAL SHEET SIZE A1 - FRAME SIZE 800 x 554
PROJ.NO. 60-8389.00 | DRAWING NO. 0003 | REV A

11 12

A B C D E F G H




NOTES

10m

REV. No. | REVISION DESCRIPTION | DRAWN | CHK | JE APP | DATE

CLIENT DRAWING No. | CLIENT APP. | DATE.

JACOBS ENGINEERING UK LTD

PROJECT OFFICE:-
JACOBS HOUSE
427 LONDON ROAD
READING
BERKSHIRE RG6 1BL

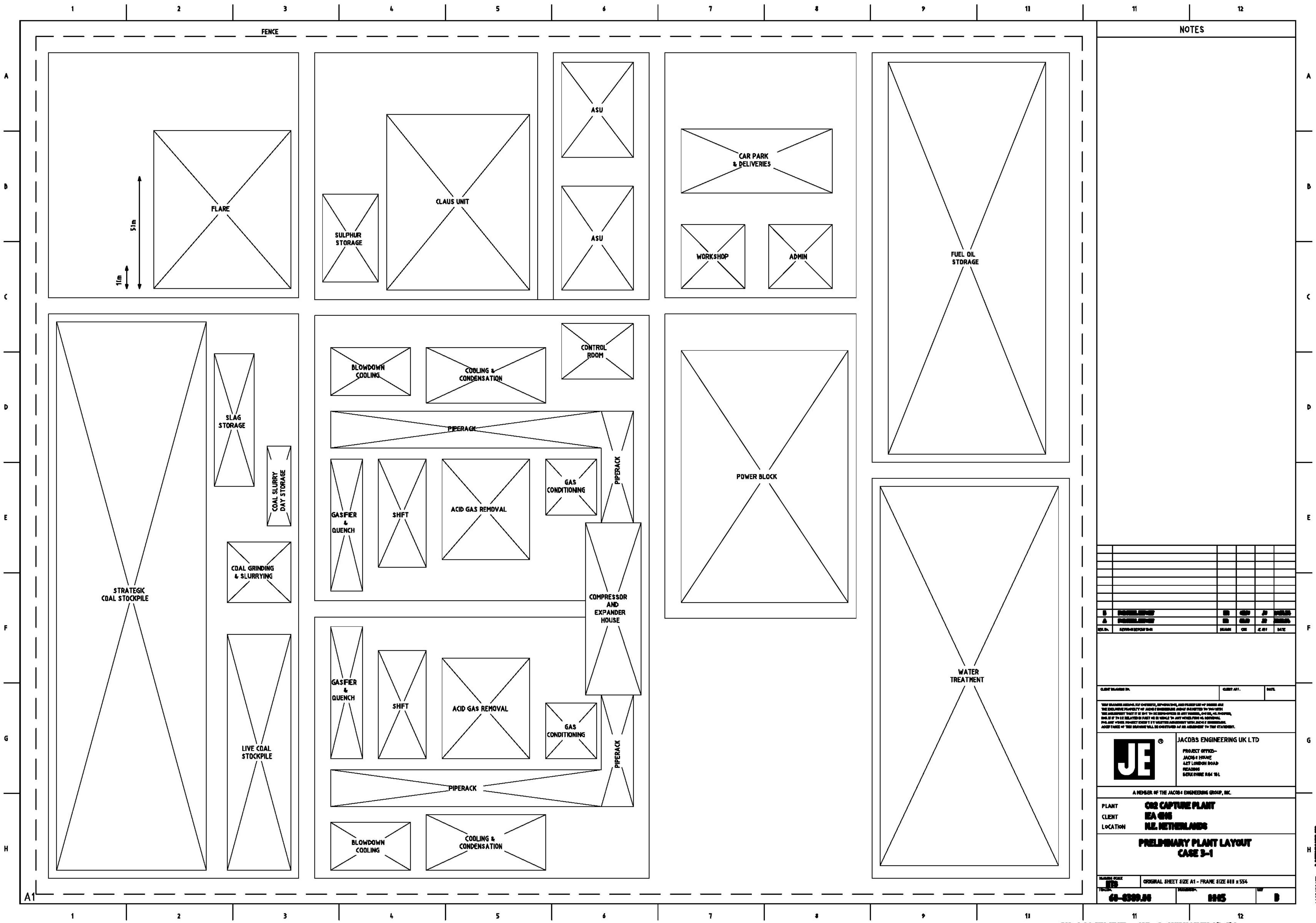
A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.

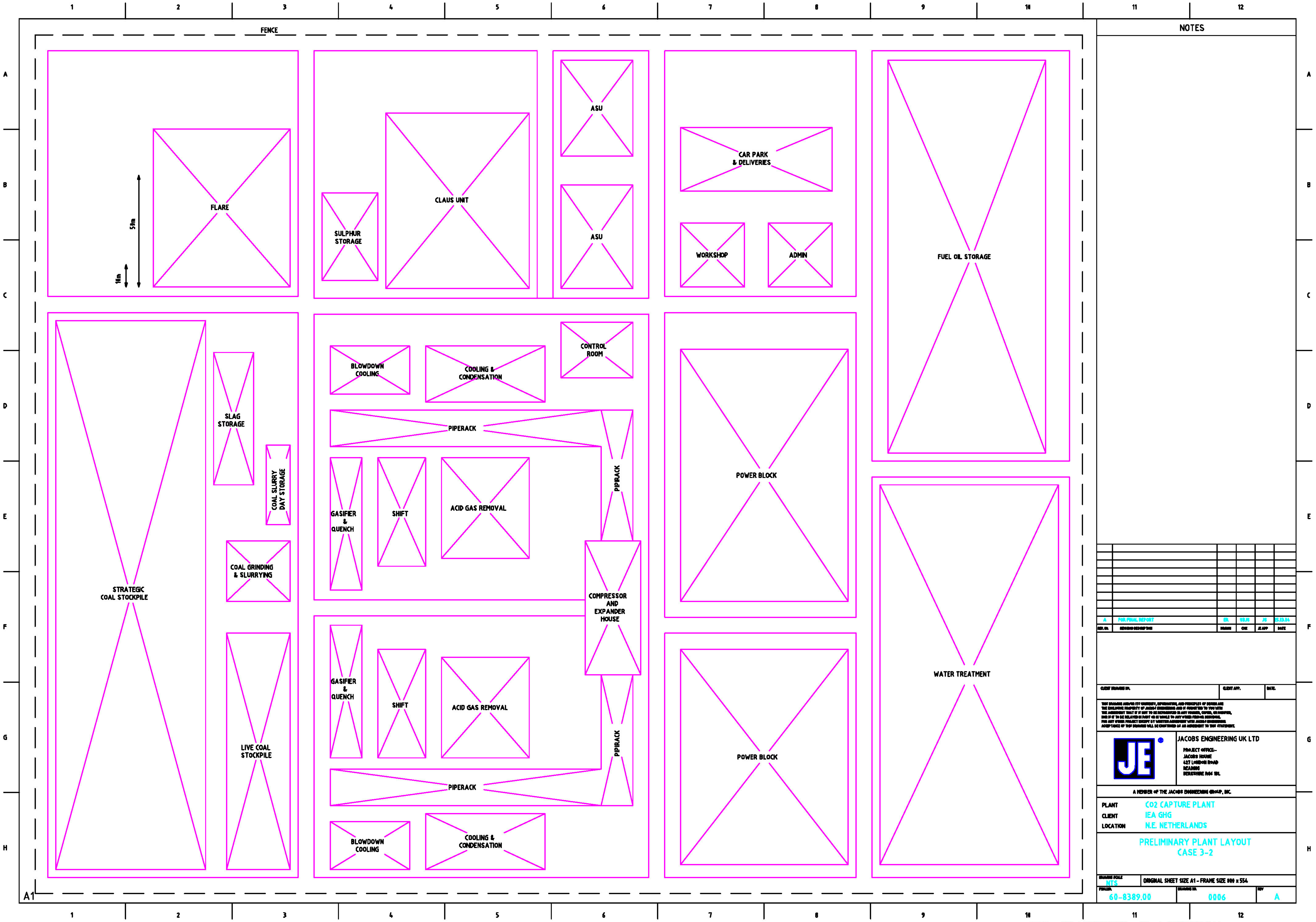
PLANT **CO2 CAPTURE PLANT**
CLIENT **IEA GHG**
LOCATION **N.E. NETHERLANDS**

**PRELIMINARY PLANT LAYOUT**
**CASE 2-2**

DRAWING SCALE **NTS** | ORIGINAL SHEET SIZE A1 - FRAME SIZE 811 x 554

PROJ. No. **60-8309.00** | DRAWING No. **0004** | REV **A**


FENCE
FLARE
51m
11m
SULPHUR STORAGE
CLAUS UNIT
ASU
ASU
CAR PARK & DELIVERIES
WORKSHOP
ADMIN
FUEL OIL STORAGE
STRATEGIC COAL STOCKPILE
SLAG STORAGE
COAL SLURRY DAY STORAGE
COAL GRINDING & SLURRYING
LIVE COAL STOCKPILE
BLOWDOWN COOLING
COOLING & CONDENSATION
CONTROL ROOM
PIPERACK
PIPERACK
GASIFIER & QUENCH
SHIFT
ACID GAS REMOVAL
GAS CONDITIONING
COMPRESSOR AND EXPANDER HOUSE
GASIFIER & QUENCH
SHIFT
ACID GAS REMOVAL
GAS CONDITIONING
PIPERACK
PIPERACK
BLOWDOWN COOLING
COOLING & CONDENSATION
POWER BLOCK
WATER TREATMENT
NOTES
A1
JACOBS ENGINEERING UK LTD
PROJECT OFFICE:-
427 LONDON ROAD
READING
A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.
PLANT
CLIENT
LOCATION
PRELIMINARY PLANT LAYOUT
CASE 3-1
ORIGINAL SHEET SIZE A1 - FRAME SIZE



FENCE
FLARE
15m
5m
SULPHUR STORAGE
CLAUS UNIT
ASU
ASU
CAR PARK & DELIVERIES
WORKSHOP
ADMIN
FUEL OIL STORAGE
STRATEGIC COAL STOCKPILE
SLAG STORAGE
COAL SLURRY DAY STORAGE
COAL GRINDING & SLURRYING
LIVE COAL STOCKPILE
BLOWDOWN COOLING
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SHIFT
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COMPRESSOR AND EXPANDER HOUSE
GASIFIER & QUENCH
SHIFT
ACID GAS REMOVAL
PIPERACK
PIPERACK
BLOWDOWN COOLING
COOLING & CONDENSATION
POWER BLOCK
POWER BLOCK
WATER TREATMENT
NOTES
A
FOR FINAL REPORT
JS
15.12.04
JACOBS ENGINEERING UK LTD
A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.
PLANT CO2 CAPTURE PLANT
CLIENT IEA GHG
LOCATION N.E. NETHERLANDS
PRELIMINARY PLANT LAYOUT
CASE 3-2
NTS
60-8389.00
0006
A
A1

# Appendix 4

Fuel/$CO_2$ Capture Plants Equipment Lists

JACOBS CONSULTANCY

# JACOBS CONSULTANCY

## EQUIPMENT LIST

Document No. 60-8389-00/P.03/1100/A4

PLANT: CO2 Capture Study Case 1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Acid Gas removal** | |
| | | | | | |
| | 10-E-401 | 8 | | Quench Water Cooler | |
| | 10-E-402 | 8 | | Stripper Condenser | |
| | 10-E-403 | 8 | | Stripper Trim Condenser | |
| | 10-E-404 | 8 | | Rich/Lean Interchanger | |
| | 10-E-405 | 8 | | Lean Amine Air Cooler | |
| | 10-E-406 | 8 | | Lean Amine trim Cooler | |
| | 10-E-407 | 8 | | Stripper Reboiler | |
| | 10-E-408 | 8 | | Condensate cooler | |
| | | | | | |
| | 10-K-401 | 8 | | Absorber Feed Fan | |
| | | | | | |
| | 10-P-401 | 8 | 4 | Quench Circulation Pump | |
| | 10-P-402 | 8 | 4 | Lean Amine Pump | |
| | 10-P-403 | 8 | 4 | Stripper Reflux Pump | |
| | 10-P-404 | 8 | 4 | Rich Amine Pump | |
| | 10-P-405 | 2 | 2 | Condensate Pump | |

NOTES:

| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | THLW | 10-Mar-04 | SBJS | 24-Apr-04 | SBJS | 26-Apr-04 | For Final Report |
| 1 | THLW | 30-Apr-04 | SBJS | 30-Apr-04 | SBJS | 30-Apr-04 | Revised for cond. Cooler |
| 2 | THLW | 04-May-04 | SBJS | 04-May-04 | SBJS | 04-May-04 | Revised for cond. Pump |

Sheet 1 of 4

| JACOBS CONSULTANCY | JACOBS CONSULTANCY<br>EQUIPMENT LIST | Document No.<br>60-8389-00/P.03/1100/A4 |
|---|---|---|

PLANT: CO2 Capture Study Case 1 — JOB NO.: 608389

CLIENT: IEA — LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Acid Gas removal** | |
| | 10-T-401 | 8 | | Quench Column | |
| | 10-T-402 | 8 | | Absorber Column | |
| | 10-T-403 | 8 | | Stripping Column | |
| | | | | | |
| | 10-TK-401 | 1 | | Amine Storage Tank | |
| | 10-TK-402 | 8 | | Sump | |
| | | | | | |
| | 10-V-401 | 8 | | 1st Stripper Condenser Knock Out Drum | |
| | 10-V-402 | 8 | | 2nd Stripper Condenser Knock Out Drum | |
| | | | | | |
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NOTES:

| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description | Sheet |
|---|---|---|---|---|---|---|---|---|
| 0 | THLW | 10-Mar-04 | SBJS | 24-Apr-04 | SBJS | 26-Apr-04 | For Final Report | Sheet 2 of 4 |
| 1 | THLW | 30-Apr-04 | SBJS | 30-Apr-04 | SBJS | 30-Apr-04 | Revised for cond. Cooler | |
| 2 | THLW | 04-May-04 | SBJS | 04-May-04 | SBJS | 04-May-04 | Revised for cond. Pump | |
| | | | | | | | | |
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| | | | | | | | | |
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| JACOBS CONSULTANCY | JACOBS CONSULTANCY<br>EQUIPMENT LIST | Document No.<br>60-8389-00/P.03/1100/A4 |
|---|---|---|

PLANT: CO2 Capture Study Case 1 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 600**<br>**Product Gas Exports** | |
| | | | | | |
| | 10-K-601 | 2 | | CO2 Compressor | Inc After cooler |
| | | | | | |
| | 10-P-601 | 2 | 2 | CO2 Compressor KO Drum Pump | |
| | | | | | |
| | 10-V-601 | 2 | | CO2 Compressor KO Drum | |
| | | | | | |
| | 10-W-601 | 2 | | Dryer Package | |
| | | | | | |
| | | | | | |
| | | | | | |
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NOTES:

| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | THLW | 10-Mar-04 | SBJS | 24-Apr-04 | SBJS | 26-Apr-04 | For Final Report |
| 1 | THLW | 30-Apr-04 | SBJS | 30-Apr-04 | SBJS | 30-Apr-04 | Revised for cond. Cooler |
| 2 | THLW | 38111 | SBJS | 04-May-04 | SBJS | 04-May-04 | Revised for cond. Pump |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

| JACOBS CONSULTANCY | JACOBS CONSULTANCY<br>EQUIPMENT LIST | Document No.<br>60-8389-00/P.03/1100/A4 |
|---|---|---|

PLANT: CO2 Capture Study Case 1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 900**<br>**Offsites** | |
| | | | | | |
| | 10-P-901 | 2 | 1 | Cooling Water Pump | Part of W-701 |
| | | | | | |
| | 10-W-901 | 1 | | Waste water treatment | |
| | 10-W-902 | 1 | | Secondary cooling system | |
| | | | | | |
| | 10-W-904 | 1 | | Fire water system | |
| | 10-W-905 | 1 | | Nitrogen & plant air | |
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| 0 | THLW | 10-Mar-04 | SBJS | 24-Apr-04 | SBJS | 26-Apr-04 | For Final Report | Sheet |
| 1 | THLW | 30-Apr-04 | SBJS | 30-Apr-04 | SBJS | 30-Apr-04 | Revised for cond. Cooler | 4 |
| 2 | THLW | 04-May-04 | SBJS | 04-May-04 | SBJS | 04-May-04 | Revised for cond. Pump | of |
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JACOBS CONSULTANCY

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## EQUIPMENT LIST

Document No. 60-8389-00/P.03/1200/A4

PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 100 Air Compression** | |
| | | | | | |
| | 21-K-201 | 4 | | Air Compressor | |
| | | | | | |
| | | | | **UNIT 200 Reformer** | |
| | 21-E-201 | 2 | | Make Gas Boiler | |
| | 21-E-202 | 2 | | HP Steam Superheater | |
| | 21-E-203 | 2 | | Turbine Steam Reheater | |
| | 21-E-204 | 2 | | ATR Feed Heater | |
| | 21-E-205 | 2 | | Hot Make Gas Boiler | |
| | | | | | |
| | 21-K-101 | 2 | | Hydrogen Recycle Compressor | |
| | | | | | |
| | 21-R-201 | 2 | | Auto-Thermal Reactor | |
| | 21-R-101 | 4 | | Desulphuriser | |
| | | | | | |
| | 21-V-201 | 2 | | Make Gas Boiler Steam Drum | |
| | | | | | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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| A | THLW | 10/3/04 | SBJS | 6/4/04 | SBJS | 6/4/04 | For Final Report |
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PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 300**<br>**Shift Unit** | |
| | 21-E-301 | 2 | | Desulphuriser Feed Heater | |
| | 21-E-302 | 2 | | BFW Heater | |
| | 21-E-303 | 2 | | DMW Heater | |
| | 21-E-304 | 2 | | Absorber Feed Cooler | |
| | 21-E-305 | 2 | | Saturator Pre-heater | |
| | 21-E-306 | 2 | | Fuel Gas Heater | |
| | 21-E-307 | 2 | | Saturator Water Heater | |
| | | | | | |
| | 21-P-301 | 2 | 2 | Process Condensate Pump | |
| | | | | | |
| | 21-R-301 | 2 | | HT Shift Reactor | |
| | 21-R-302 | 2 | | LT Shift Reactor | |
| | | | | | |
| | 21-T-301 | 2 | | Saturator | |
| | | | | | |
| | 21-V-301 | 2 | | Process Condensate Drum 1 | |
| | 21-V-302 | 2 | | Process Condensate Drum 2 | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Acid Gas removal** | |
| | | | | | |
| | 21-E-401 | 2 | | Stripper Reboiler | |
| | 21-E-402 | 2 | | Lean / Semi-Lean Mdea | |
| | 21-E-403 | 2 | | Lean Mdea Cooler | |
| | 21-E-405 | 2 | | LP Flash Overhead | |
| | 21-E-406 | 2 | | LP Flash Overhead Vent Cooler | |
| | | | | | |
| | 21-P-401 | 2 | 2 | Lean Mdea Pump | |
| | 21-P-402 | 2 | 2 | Lp Flash Reflux Pump | |
| | 21-P-403 | 2 | 2 | Semi-Lean Mdea Pump | |
| | 21-P-404 | 2 | 2 | Stripper Feed Pump | |
| | 21-PT-401 | 2 | | Lean Mdea Pump Turbine | |
| | | | | | |
| | 21-T-401 | 2 | | CO2 Absorber | |
| | 21-T-402 | 2 | | CO2 Stripper | |
| | 21-T-403 | 2 | | HP Flash Column | |
| | 21-T-404 | 2 | | LP Flash Column | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Acid Gas removal** | |
| | 21-TK-501 | 1 | | Amine Storage Tank | |
| | 21-TK-502 | 2 | | Sump | |
| | | | | | |
| | 21-V-402 | 2 | | LP Flash Reflux Receiver | |
| | | | | | |
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PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 600**<br>**Product Gas Exports** | |
| | | | | | |
| | 21-K-601 | 2 | | CO2 Compressor | |
| | | | | | |
| | 21-P-601 | 2 | 2 | CO2 Compressor KO Drum Pump | |
| | | | | | |
| | 21-V-601 | 2 | | CO2 Compressor KO Drum | |
| | | | | | |
| | 21-W-601 | 2 | | Dryer Package | |

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PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 700**<br>**Power Block** | |
| | | | | | |
| | 21-E-701 | 2 | | Alternator Turbine Condenser | |
| | 21-E-702 | 2 | | Condensate Stripper<br>Feed / Product Exchanger | |
| | | | | | |
| | 21-P-701 | 2 | 2 | BFW Pump | |
| | 21-P-702 | 2 | 2 | Turbine Condensate Pump | |
| | | | | | |
| | 21-Q-701 | 2 | | Alternator | |
| | 21-QT-701 | 2 | | Alternator Turbine | |
| | | | | | |
| | 21-T-701 | 1 | | De-Aerator Column | |
| | 21-T-702 | 2 | | Process Condensate Stripper | |
| | | | | | |
| | 21-V-701 | 1 | | De-Aerator Vessel | |
| | 21-V-702 | 2 | | Turbine Condensate Vessel | |
| | | | | | |
| | 21-Z-701 | 2 | | Turbine Ejector Unit | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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PLANT: CO2 Capture Study Case 2-1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 900**<br>**Offsites** | |
| | | | | | |
| | 21-P-901 | 2 | 1 | Cooling Water Pump | |
| | | | | | |
| | 21-W-901 | 1 | | DMW & Waste water treatment | |
| | 21-W-902 | 1 | | Secondary cooling system | |
| | 21-W-903 | 1 | | Flare system | |
| | 21-W-904 | 1 | | Fire water system | |
| | 21-W-905 | 1 | | Nitrogen & plant air | |
| | | | | | |
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CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 100 Desulphurisation** | |
| | | | | | |
| | 22-K-101 | 4 | | Air Compressor | |
| | | | | | |
| | | | | **UNIT 200 Reformer** | |
| | 22-E-201 | 2 | | Make Gas Boiler | |
| | 22-E-202 | 2 | | HP Steam Superheater | |
| | 22-E-203 | 2 | | Turbine Steam Reheater | |
| | 22-E-204 | 2 | | ATR Feed Heater | |
| | 22-E-205 | 2 | | Hot Make Gas Boiler | |
| | | | | | |
| | 22-K-201 | 2 | | Hydrogen Recycle Compressor | |
| | | | | | |
| | 22-R-201 | 4 | | Desulphuriser | |
| | 22-R-202 | 2 | | Auto-Thermal Reactor | |
| | | | | | |
| | 22-V-201 | 2 | | Make Gas Boiler Steam Drum | |
| | | | | | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 300**<br>**Shift Unit** | |
| | 22-K-301 | 2 | | Fuel Gas Compressor | |
| | | | | | |
| | 22-E-301 | 2 | | Desulphuriser Feed Heater | |
| | 22-E-302 | 2 | | BFW Heater | |
| | 22-E-303 | 2 | | DMW Heater | |
| | 22-E-304 | 2 | | Absorber Feed Cooler | |
| | | | | | |
| | | | | | |
| | 22-P-301 | 2 | 2 | Process Condensate Pump | |
| | | | | | |
| | 22-R-301 | 2 | | HT Shift Reactor | |
| | 22-R-302 | 2 | | LT Shift Reactor | |
| | | | | | |
| | | | | | |
| | | | | | |
| | 22-V-301 | 2 | | Process Condensate Drum 1 | |
| | 22-V-302 | 2 | | Process Condensate Drum 2 | |

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PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Acid Gas removal** | |
| | | | | | |
| | 22-E-401 | 2 | | Stripper Reboiler | |
| | 22-E-402 | 2 | | Lean / Semi-Lean Mdea | |
| | 22-E-403 | 2 | | Lean Mdea Cooler | |
| | 22-E-405 | 2 | | LP Flash Overhead | |
| | 22-E-406 | 2 | | LP Flash Overhead Vent | |
| | | | | | |
| | 22-P-401 | 2 | 2 | Lean Amine Pump | |
| | 22-P-402 | 2 | 2 | Lp Flash Reflux Pump | |
| | 22-P-403 | 2 | 2 | Semi-Lean Amine Pump | |
| | 22-P-404 | 2 | 2 | Stripper Feed Pump | |
| | 22-PT-401 | 2 | | Rich Amine Pump Turbine | |
| | | | | | |
| | 22-T-401 | 2 | | CO2 Absorber | |
| | 22-T-402 | 2 | | CO2 Stripper | |
| | 22-T-403 | 2 | | HP Flash Column | |
| | 22-T-404 | 2 | | LP Flash Column | |

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PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Acid Gas removal** | |
| | 22-TK-401 | 1 | | Selexol Storage Tank | |
| | 22-TK-402 | 2 | | Sump | |
| | | | | | |
| | 22-V-402 | 2 | | LP Flash Reflux Receiver | |

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PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 600**<br>**Product Gas Exports** | |
| | | | | | |
| | 22-K-601 | 2 | | CO2 Compressor | |
| | | | | | |
| | 22-P-601 | 2 | 2 | CO2 Compressor KO Drum Pump | |
| | | | | | |
| | 22-V-601 | 2 | | CO2 Compressor KO Drum | |
| | | | | | |
| | 22-W-601 | 2 | | Dryer Package | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 700**<br>**Power Block** | |
| | | | | | |
| | 22-E-701 | 2 | | Alternator Turbine Condenser | |
| | 22-E-702 | 2 | | Condensate Stripper Feed / Product Exchanger | |
| | | | | | |
| | 22-P-701 | 2 | 2 | BFW Pump | |
| | 22-P-702 | 2 | 2 | Turbine Condensate Pump | |
| | | | | | |
| | 22-Q-701 | 2 | | Alternator | |
| | 22-QT-701 | 2 | | Alternator Turbine | |
| | | | | | |
| | 22-T-701 | 1 | | De-Aerator Column | |
| | 22-T-702 | 2 | | Process Condensate Stripper | |
| | | | | | |
| | 22-V-701 | 1 | | De-Aerator Vessel | |
| | 22-V-702 | 2 | | Turbine Condensate Vessel | |
| | | | | | |
| | 22-Z-701 | 1 | | Turbine Ejector Unit | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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PLANT: CO2 Captute Study Case 2-2 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 900**<br>**Offsites** | |
| | | | | | |
| | 22-P-901 | 2 | 1 | Cooling Water Pump | |
| | | | | | |
| | 22-W-901 | 1 | | Waste water treatment | |
| | 22-W-902 | 1 | | Secondary cooling system | |
| | 22-W-903 | 1 | | Flare system | |
| | 22-W-904 | 1 | | Fire water system | |
| | 22-W-905 | 1 | | Nitrogen & plant air | |
| | | | | | |
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## EQUIPMENT LIST

Document No. 60-8389-00/P.03/1400/A4

PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 100- Air Seperation Unit** | |
| | | | | | |
| | 31-W-101 | 2 | | Air Separation Unit | |
| | | | | | |
| | | | | **UNIT 200 Feedstock preparation** | |
| | | | | | |
| | 31-P-201 | 4 | 2 | Coal Slurry Feed Pump | Part of W-301 |
| | | | | | |
| | 31-W-201 | 2 | | Coal preparation | |

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| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
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PLANT: CO2 Capture Study Case 3-1 — JOB NO.: 608389

CLIENT: IEA — LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 300**<br>**Gasification Unit** | Part of W-301 |
| | 31-E-301 | 4 | 1 | LP Flash Condenser | Part of W-301 |
| | 31-E-302 | 4 | 1 | BFW Heater 1 | Part of W-301 |
| | 31-E-303 | 4 | 1 | BFW Heater 2 | Part of W-301 |
| | 31-E-304 | 4 | 1 | Oxygen Heater | |
| | | | | | |
| | | | | | |
| | 31-P-301 | 4 | 6 | Black Water Pump | Part of W-301 |
| | 31-P-302 | 4 | 6 | BFW Pump | Part of W-301 |
| | 31-P-303 | 4 | 6 | Grey Water Pump | Part of W-301 |
| | | | | | |
| | 31-R-301 | 4 | 1 | Gasifier | Part of W-301 |
| | | | | | |
| | 31-T-301 | 4 | 1 | Scrubber | Part of W-301 |
| | | | | | |
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PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 300**<br>**Gasification Unit** | |
| | 31-V-301 | 4 | 1 | Quench | Part of W-301 |
| | 31-V-302 | 4 | 1 | LP Flash Drum | Part of W-301 |
| | 31-V-303 | 4 | 1 | LP Flash Overhead Cond Drum | Part of W-301 |
| | 31-V-304 | 4 | 1 | Knockout Drum | Part of W-301 |
| | 31-V-305 | 4 | 1 | Atmospheric Flash Drum | Part of W-301 |
| | 31-V-306 | 4 | 1 | Vacuum Flash Drum | Part of W-301 |
| | | | | | |
| | 31-W-301 | 4 | 1 | Gasification Package | Part of W-301 |
| | 31-W-302 | 4 | 1 | Vacuum Package | Part of W-301 |

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PLANT: CO2 Capture Study Case 3-1 JOB NO.: 608389

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Gas Treatment** | |
| | 31-E-401 | 2 | | Shift Interchanger | |
| | 31-E-402 | 2 | | High Pressure Boiler | |
| | 31-E-403 | 2 | | High Pressure BFW Heater | |
| | 31-E-404 | 2 | | High Pressure Water Heater 3 | |
| | 31-E-405 | 2 | | High Pressure Water Heater 2 | |
| | 31-E-406 | 2 | | High Pressure Water Heater 1 | |
| | 31-E-407 | 2 | | LP Boiler | |
| | 31-E-408 | 2 | | Low Pressure BFW Heater | |
| | 31-E-409 | 2 | | Expander Preheater | |
| | 31-E-410 | 2 | | Fuel Gas Heater | |
| | | | | | |
| | 31-E-412 | 2 | | N2 Heater | |
| | | | | | |
| | 31-K-401 | 2 | | Fuel Gas Expander | |
| | 31-K-402 | 2 | | Recycle Compressor | |
| | 31-K-403 | 2 | | Selexol N2 Compressor | |
| | 31-K-404 | 2 | | N2 Compressor | |

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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Gas Treatment** | |
| | 31-K-405 | 2 | | Main N2 Compressor | |
| | 31-K-406 | 2 | | Tail Gas Compressor | |
| | 31-P-401 | 2 | 2 | Desaturator Circulation Pump | |
| | 31-P-402 | 2 | 2 | Low Pressure BFW Pump | |
| | 31-P-403 | 2 | 2 | Intermediate Pressure BFW Pump | |
| | 31-P-404 | 2 | 2 | BFW Circulating Pump | |
| | 31-P-405 | 2 | 2 | High Pressure BFW Pump | |
| | 31-P-409 | 2 | 2 | Process Water Make-up Pump | |
| | | | | | |
| | | | | | |
| | 31-R-401 | 2 | | Shift Reactor | |
| | 31-T-401 | 2 | | Desaturator | |
| | | | | | |
| | 31-V-401 | 2 | | HP Steam Drum | |
| | 31-V-402 | 2 | | LP Steam Drum | |
| | | | | | |
| | | | | | |

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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 500**<br>**Acid Gas removal** | |
| | | | | | |
| | 31-E-501 | 2 | | Stripper Reboiler | |
| | 31-E-502 | 2 | | Stripped Gas Condenser | |
| | 31-E-503 | 2 | | Lean/Rich Exchanger | |
| | 31-E-504 | 2 | | Lean Solvent Cooler | |
| | 31-E-505 | 2 | | Semi-Lean Cooler | |
| | 31-E-506 | 2 | | Loaded Solvent Cooler | |
| | 31-E-507 | 2 | | Compressed Gas Cooler | |
| | 31-E-508 | 2 | | Flash Gas Cooler | |
| | | | | | |
| | 31-TK-501 | 1 | | Selexol Storage Tank | |
| | 31-TK-502 | 2 | | Sump | |
| | | | | | |
| | | | | | |
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CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 500**<br>**Acid Gas removal** | |
| | 31-P-501 | 2 | 2 | Lean Solution Pump | |
| | 31-P-502 | 2 | 2 | Rich Solution Pump | |
| | 31-P-503 | 10 | 2 | Semi-lean Pump | |
| | 31-P-504 | 2 | 2 | Stripper Reflux Pump | |
| | 31-P-505 | 2 | 2 | Loaded Solvent Pump | |
| | 31-PT-506 | 10 | | Rich solvent expander | |
| | 31-T-501 | 2 | 2 | H2S Absorber | |
| | 31-T-502 | 2 | 2 | H2S Concentrator | |
| | 31-T-503 | 2 | 2 | CO2 Absorber | |
| | 31-T-504 | 2 | 2 | Lean Solution Stripper | |
| | 31-V-501 | 2 | 2 | HP Flash Drum | |
| | 31-V-502 | 2 | 2 | MP Flash Drum | |
| | 31-V-503 | 2 | 2 | LP Flash Drum | |
| | 31-V-504 | 2 | 2 | Flash Gas KO Drum | |
| | 31-V-505 | 2 | 2 | Rich Flash | |
| | 31-V-506 | 2 | 2 | Stripper Overhead Drum | |
| | 31-W-501 | 2 | 2 | Claus unit | |

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CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 600**<br>**Product Gas Exports** | |
| | | | | | |
| | 31-K-601 | 2 | | CO2 Compressor | |
| | | | | | |
| | 31-P-601 | 2 | 2 | CO2 Compressor KO Drum Pump | |
| | | | | | |
| | 31-V-601 | 2 | | CO2 Compressor KO Drum | |
| | | | | | |
| | 31-W-601 | 2 | | Dryer Package | |

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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 700**<br>**Power Block** | |
| | | | | | |
| | 31-E-705 | 1 | | Low Pressure Superheater | Part of W-701 |
| | 31-E-710 | 1 | | High Pressure Superheater | Part of W-701 |
| | 31-E-715 | 1 | | Steam Turbine Condenser | Part of W-701 |
| | 31-E-715 | 1 | | Steam Dump Condenser | |
| | | | | | |
| | 31-K-701 | 1 | | Gas Turbine | Part of W-701 |
| | 31-K-702 | 1 | | Steam Turbine | Part of W-701 |
| | | | | | |
| | 31-P-704 | 2 | 1 | Condensate Pump | Part of W-701 |
| | | | | | |
| | 31-V-701 | 1 | | De-areator | Part of W-701 |
| | | | | | |
| | 31-W-701 | 1 | | Combined Cycle Unit | Part of W-701 |
| | | | | | |
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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 900 Offsites** | |
| | | | | | |
| | 31-P-901 | 2 | 1 | Cooling Water Pump | |
| | 31-P-902 | 2 | 1 | Back-up fuel pumps | |
| | 31-TK-901 | 2 | | Back-fuel storage tank | |
| | | | | | |
| | | | | | |
| | 31-W-901 | 1 | | Waste water treatment | |
| | 31-W-902 | 1 | | Secondary cooling system | |
| | 31-W-903 | 1 | | Flare system | |
| | 31-W-904 | 1 | | Fire water system | |
| | 31-W-905 | 1 | | Nitrogen & plant air | |

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CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 100- Air Seperation Unit** | |
| | 32-W-101 | 2 | | Air Separation Unit | |
| | | | | **UNIT 200 Feedstock preparation** | |
| | 32-P-201 | 4 | 2 | Coal Slurry Feed Pump | Part of W-301 |
| | 32-W-201 | 2 | | Coal preparation | |

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CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 300**<br>**Gasification Unit** | Part of W-301 |
| | 32-E-301 | 4 | 1 | LP Flash Condenser | Part of W-301 |
| | 32-E-302 | 4 | 1 | BFW Heater 1 | Part of W-301 |
| | 32-E-303 | 4 | 1 | BFW Heater 2 | Part of W-301 |
| | 32-E-304 | 4 | 1 | Oxygen Heater | |
| | | | | | |
| | 32-P-301 | 4 | 6 | Black Water Pump | Part of W-301 |
| | 32-P-302 | 4 | 6 | BFW Pump | Part of W-301 |
| | 32-P-303 | 4 | 6 | Grey Water Pump | Part of W-301 |
| | | | | | |
| | 32-R-301 | 4 | 1 | Gasifier | Part of W-301 |
| | | | | | |
| | 32-T-301 | 4 | 1 | Scrubber | Part of W-301 |
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| Rev. | Item Number | No. Installed W'king | St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 300**<br>**Gasification Unit** | |
| | 32-V-301 | 4 | 1 | Quench | Part of W-301 |
| | 32-V-302 | 4 | 1 | LP Flash Drum | Part of W-301 |
| | 32-V-303 | 4 | 1 | LP Flash Overhead Cond Drum | Part of W-301 |
| | 32-V-304 | 4 | 1 | Knockout Drum | Part of W-301 |
| | 32-V-305 | 4 | 1 | Atmospheric Flash Drum | Part of W-301 |
| | 32-V-306 | 4 | 1 | Vacuum Flash Drum | Part of W-301 |
| | | | | | |
| | 32-W-301 | 4 | 1 | Gasification Package | Part of W-301 |
| | 32-W-302 | 4 | 1 | Vacuum Package | Part of W-301 |

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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Gas Treatment** | |
| | 32-E-401 | 2 | | Shift Interchanger | |
| | 32-E-402 | 2 | | High Pressure Boiler | |
| | 32-E-403 | 2 | | High Pressure BFW Heater | |
| | 32-E-404 | 2 | | High Pressure Water Heater 3 | |
| | 32-E-405 | 2 | | High Pressure Water Heater 2 | |
| | 32-E-406 | 2 | | High Pressure Water Heater 1 | |
| | 32-E-407 | 2 | | LP Boiler | |
| | 32-E-408 | 2 | | Low Pressure BFW Heater | |
| | 31-E-409 | 2 | | Expander Preheater | |
| | 31-E-410 | 2 | | Fuel Gas Heater | |
| | | | | | |
| | | | | | |
| | | | | | |
| | 32-K-401 | 2 | | Fuel Gas expander | |
| | 32-K-402 | 2 | | Recycle Compressor | |
| | 32-K-403 | 2 | | Selexol N2 Compressor | |
| | 32-K-404 | 2 | | Nitrogen Compressor | |

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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 400**<br>**Gas Treatment** | |
| | 32-K-405 | 2 | | Main N2 Compressor | |
| | 32-K-406 | 2 | | Tail Gas Compressor | |
| | | | | | |
| | 32-P-401 | 2 | 2 | Desaturator Circulation Pump | |
| | 32-P-402 | 2 | 2 | Low Pressure BFW Pump | |
| | 32-P-403 | 2 | 2 | Intermediate Pressure BFW Pump | |
| | 32-P-404 | 2 | 2 | BFW Circulating Pump | |
| | 32-P-405 | 2 | 2 | High Pressure BFW Pump | |
| | 32-P-409 | 2 | 2 | Process Water Make-up Pump | |
| | | | | | |
| | 32-R-401 | 2 | | Shift Reactor | |
| | 32-T-401 | 2 | | Desaturator | |
| | | | | | |
| | 32-V-401 | 2 | | HP Steam Drum | |
| | 32-V-402 | 2 | | LP Steam Drum | |
| | | | | | |
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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 500**<br>**Acid Gas removal** | |
| | | | | | |
| | 32-E-501 | 2 | | Stripper Reboiler | |
| | 32-E-502 | 2 | | Stripped Gas Condenser | |
| | 32-E-503 | 2 | | Lean/Rich Exchanger | |
| | 32-E-504 | 2 | | Lean Solvent Cooler | |
| | 32-E-505 | 2 | | Semi-Lean Cooler | |
| | 32-E-506 | 2 | | Loaded Solvent Cooler | |
| | 32-E-507 | 2 | | Compressed Gas Cooler | |
| | 32-E-508 | 2 | | Flash Gas Cooler | |
| | | | | | |
| | 32-TK-501 | 1 | | Selexol Storage Tank | |
| | 32-TK-502 | 1 | | Sump | |
| | | | | | |
| | | | | | |
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| Rev. | Item Number | No. Installed W'king | St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 500**<br>**Acid Gas removal** | |
| | 32-P-501 | 2 | 2 | Lean Solution Pump | |
| | 32-P-502 | 2 | 2 | Rich Solution Pump | |
| | 32-P-503 | 12 | 2 | Semi-lean Pump | |
| | 32-P-504 | 2 | 2 | Stripper Recycle Pump | |
| | 32-P-505 | 2 | 2 | Loaded Solvent Pump | |
| | 32-PT-506 | 12 | | Rich solvent expander | |
| | 32-T-501 | 2 | | H2S Absorber | |
| | 32-T-502 | 2 | | H2S Concentrator | |
| | 32-T-503 | 2 | | CO2 Absorber | |
| | 32-T-504 | 2 | | Lean Solution Stripper | |
| | 32-V-501 | 2 | | HP Flash Drum | |
| | 32-V-502 | 2 | | MP Flash Drum | |
| | 32-V-503 | 2 | | LP Flash Drum | |
| | 32-V-504 | 2 | | Flash Gas KO Drum | |
| | 32-V-505 | 2 | | Rich Flash | |
| | 32-V-506 | 2 | | Stripper Overhead Drum | |
| | 32-W-501 | 2 | | Claus unit | |

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| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 600 Product Gas Exports** | |
| | | | | | |
| | 32-K-601 | 2 | | CO2 Compressor | |
| | | | | | |
| | 32-P-601 | 2 | 2 | CO2 Compressor KO Drum Pump | |
| | | | | | |
| | 32-V-601 | 2 | | CO2 Compressor KO Drum | |
| | | | | | |
| | 32-W-601 | 2 | | Dryer Package | |
| | | | | | |
| | 32-W-602 | 1 | | Fuel Gas Export Pipeline | |

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| --- | --- | --- | --- | --- | --- |
| | | | | **UNIT 700**<br>**Power Block** | |
| | | | | | |
| | 32-E-701 | 2 | | Low Temperature Economiser | Part of W-701 |
| | 32-E-702 | 2 | | HRSG Low Pressure Boiler | Part of W-701 |
| | 32-E-703 | 2 | | Intermediate Pressure Economiser | Part of W-701 |
| | 32-E-704 | 2 | | Intermediate Pressure Boiler | Part of W-701 |
| | | | | | |
| | 32-E-706 | 2 | | High Pressure Economiser 1 | Part of W-701 |
| | 32-E-707 | 2 | | Intermediate Pressure Superheater 1 | Part of W-701 |
| | 32-E-708 | 2 | | High Pressure Economiser 2 | Part of W-701 |
| | 32-E-709 | 2 | | HRSG High Pressure Boiler | Part of W-701 |
| | 32-E-710 | 2 | | High Pressure Superheater 1 | Part of W-701 |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | 32-E-715 | 2 | | Steam Turbine Condenser | |
| | 32-E-716 | 1 | | Steam Dump Condenser | Single unit for both streams |

NOTES:

| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
| --- | --- | --- | --- | --- | --- | --- | --- |
| A | THLW | 10-Mar-04 | SBJS | 24-Mar-04 | SBJS | 24/3/04 | For Final Report |

| JACOBS CONSULTANCY | JACOBS CONSULTANCY | Document No. |
|---|---|---|
| | EQUIPMENT LIST | 60-8389-00/P.03/1500/A4 |

PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 700**<br>**Power Block** | |
| | 32-K-701 | 2 | | Gas Turbine | Part of W-701 |
| | 32-K-702 | 1 | | Steam Turbine | Part of W-701 |
| | | | | | |
| | | | | | |
| | 32-P-703 | 4 | 2 | HP BFW Pump | Part of W-701 |
| | 32-P-704 | 4 | 2 | Condensate Pump | Part of W-701 |
| | | | | | |
| | | | | | |
| | 32-V-701 | 2 | | De-areator | Part of condenser |
| | 32-V-702 | 2 | | HRSG HP Steam Drum | Part of W-701 |
| | 32-V-703 | 2 | | HRSG IP Steam Drum | Part of W-701 |
| | 32-V-704 | 2 | | HRSG LP Steam Drum | Part of W-701 |
| | | | | | |
| | 32-W-701 | 2 | | Combined Cycle Unit | Part of W-701 |
| | | | | | |
| | | | | | |
| | | | | | |

NOTES:

| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| A | THLW | 10-Mar-04 | SBJS | 24-Mar-04 | SBJS | 24/3/04 | For Final Report |

| JACOBS CONSULTANCY | JACOBS CONSULTANCY<br>EQUIPMENT LIST | Document No.<br>60-8389-00/P.03/1500/A4 |
|---|---|---|

PLANT: CO2 Capture Study Case 3-2 JOB NO.: 608389
CLIENT: IEA LOCATION: NE Netherlands

| Rev. | Item Number | No. Installed W'king | No. Installed St'by | Description | Remarks |
|---|---|---|---|---|---|
| | | | | **UNIT 900**<br>**Offsites** | |
| | | | | | |
| | 32-P-901 | 2 | 1 | Cooling Water Pump | |
| | | | | | |
| | 32-P-902 | 2 | 1 | Back-up fuel pumps | |
| | 32-TK-901 | 2 | | Back-fuel storage tank | |
| | | | | | |
| | | | | | |
| | 32-W-901 | 1 | | Waste water treatment | |
| | 32-W-902 | 1 | | Secondary cooling system | |
| | 32-W-903 | 1 | | Flare system | |
| | 32-W-904 | 1 | | Fire water system | |
| | 32-W-905 | 1 | | Nitrogen & plant air | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |

NOTES:

| Rev | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| A | THLW | 10-Mar-04 | SBJS | 24-Mar-04 | SBJS | 24/3/04 | For Final Report |

Sheet 11 of 11

# Appendix 5

Fuel/$CO_2$ Capture Plants Power Consumption/Production and Utility Usage

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

Power schedule

Document No. 60-8389-00/P.03/1100/A4

**PLANT:** CO2 Capture Study Case 1
**LOCATION:** NE Netherlands
**CLIENT:** IEA
**PROJECT:** 608389



Revised this issu ↓

| Sect | Item no. | Item Name | no. operating | Power (kW) Each | Total |
|---|---|---|---|---|---|
| 100 | | | | | |
| 200 | | | | | |
| 300 | | | | | |
| 400 | 10-K-401 | Absorber Feed Fan | 8 | 903 | **7,224** |
| | 10-E-402 | Stripper Condenser | 8 | 153 | **1,223** |
| | 10-E-405 | Lean Amine Air Cooler | 8 | 73 | **583** |
| | 10-P-401 | Quench Circulation Pump | 8 | 65 | **520** |
| | 10-P-402 | Lean Amine Pump | 8 | 63 | **504** |
| | 10-P-403 | Stripper Reflux Pump | 8 | 8 | **64** |
| | 10-P-404 | Rich Amine Pump | 8 | 109 | **872** |
| | 10-P-405 | Condensate Pump | 2 | 108 | **215** |
| 600 | 10-K-601 | CO2 Compressor | 2 | 10,836 | **21,673** |
| | 10-P-601 | CO2 Compressor KO Drum Pump | 2 | 0 | **0** |
| 900 | 10-P-901 | Cooling Water Pump | 2 | 1,796 | **3,591** |
| | | Misc items | | | **2,000** |
| | Plant total | | | | **38,470** |

Total Power output (MW) 38.5

**NOTE: All data is for 1 train**

| Issue | A | Date | | Date | | Date | | Date | | Date | Sht. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | For Report | | | | | | | | | | 12 |
| Made by / Revised by | THLW | 10-mrt-04 | | | | | | | | | of |
| Checked by | SBJS | 24-apr-04 | | | | | | | | | XX |
| Approved by | | | | | | | | | | | |

**JACOBS CONSULTANCY**

# JACOBS CONSULTANCY UK LTD

Power schedule

Document No. 60-8389-00/P.03/2100/A4



**PLANT:** CO2 Capture Study Case 2-1
**LOCATION:** NE Netherlands
**CLIENT:** IEA
**PROJECT:** 608389

Revised this issu ↓

| Sect | Item no. | Item Name | no. operating | Power (kW) Each | Total |
|---|---|---|---|---|---|
| 100 | 21-K-201 | Air Compressor | 2 | 49,583 | |
| | | | | | **49,583** |
| 200 | 21-K-101 | Hydrogen Recycle Compressor | 1 | 40 | |
| | | | | | **40** |
| 300 | 21-P-301 | Process Condensate Pump | 1 | 79 | |
| | | | | | **79** |
| 400 | 21-P-401 | Lean Mdea Pump | 1 | 1,824 | |
| | 21-P-402 | Lp Flash Reflux Pump | 1 | 3 | |
| | 21-P-403 | Semi-Lean Mdea Pump | 1 | 8,549 | |
| | 21-P-404 | Stripper Feed Pump | 1 | 304 | |
| | 21-PT-401 | Lean Mdea Pump Turbine | 1 | -2,908 | |
| | | | | | **7,773** |
| 600 | 21-K-601 | CO2 Compressor | 1 | 15,923 | |
| | 21-P-601 | CO2 Compressor KO Drum Pump | 1 | 8 | |
| | | | | | **15,930** |
| 700 | 21-P-701 | BFW Pump | 1 | 1,020 | |
| | 21-P-702 | Turbine Condensate Pump | 1 | 4 | |
| | 21-QT-701 | Alternator Turbine | 1 | -21,504 | |
| | | | | | **-20,480** |
| 900 | 21-P-901 | Cooling Water Pump | 2 | 2,039 | |
| | Misc users | HVAC, lighting and small power | | 3,000 | |
| | | | | | **5,039** |

Total Power output (MW) 58.0

**NOTE: All data is for 1 train**

| Issue | A | Date | | Date | | Date | | Date | | Date | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | For Report | | | | | | | | | | Sht. |
| Made by / Revised by | THLW | 10-mrt-04 | | | | | | | | | 12 |
| Checked by | SBJS | 0-jan-00 | | | | | | | | | of |
| Approved by | | | | | | | | | | | 16 |

| JACOBS CONSULTANCY | JACOBS CONSULTANCY UK LTD<br>Power schedule | Document No. 60-8389-00/P.03/2200/A4 |
|---|---|---|



**PLANT:** CO2 Captute Study Case 2-2
**LOCATION:** NE Netherlands
**CLIENT:** IEA
**PROJECT:** 608389

Revised this issue ↓

| Item no. | Item Name | no. operating | Power (kW) Each | Total | |
|---|---|---|---|---|---|
| 22-K-101 | Air Compressor | 2 | | 49,209 | |
| | | | | | **49,209** |
| 22-K-201 | Hydrogen Recycle Compressor | 1 | | 33 | |
| | | | | | **33** |
| 22-P-301 | Process Condensate | 1 | | 79 | |
| 22-K-301 | Fuel Gas Compressor | 1 | | 4,767 | |
| | | | | | **4,845** |
| 22-P-401 | Lean Amine Pump | 1 | | 1,823 | |
| 22-P-402 | Lp Flash Reflux Pump | 1 | | 3 | |
| 22-P-403 | Semi-Lean Amine Pump | 1 | | 8,542 | |
| 22-P-404 | Stripper Feed Pump | 1 | | 304 | |
| 22-PT-401 | Rich Amine Pump Turbine | 1 | | -3,109 | |
| | | | | | **7,563** |
| 22-K-601 | CO2 Compressor | 1 | | 15,937 | |
| 22-P-601 | CO2 Compressor KO Drum Pump | 1 | | 8 | |
| | | | | | **15,945** |
| 22-P-701 | BFW Pump | 1 | | 1,019 | |
| 22-P-702 | Turbine Condensate | 1 | | 4 | |
| 22-QT-701 | Alternator Turbine | 1 | | -35,530 | |
| | | | | | **-34,506** |
| 22-P-901 | Cooling Water Pump | 2 | | 2,359 | |
| | Misc | | | 3,000 | |
| | | | | | **5,359** |
| Total Power output (MW) | | | | 48.4 | |

**NOTE: All data is for 1 train**

| Issue | A | Date | | Date | | Date | | Date | | Date | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | For Report | | | | | | | | | | Sht. |
| Made by / Revised by | THLW | 10-mrt-04 | | | | | | | | | 10 |
| Checked by | | | | | | | | | | | of |
| Approved by | | | | | | | | | | | 14 |

**JACOBS CONSULTANCY**

**JACOBS CONSULTANCY UK LTD**

Power schedule

Document No. 60-8389-00/P.03/3100/A4



**PLANT:** CO2 Captute Study Case 3-1
**LOCATION:** NE Netherlands
**CLIENT:** IEA
**PROJECT:** 608389

Revised this issue ↓

| | Item no. | Item Name | no. operating | Power (kW) Each | Total |
|---|---|---|---|---|---|
| 100 | 31-W-101 | Air Separation Unit | 1 | 44,309 | |
| | | | | | **44,309** |
| 200 | 31-P-201 | Coal Slurry Feed Pump | 1 | 466 | |
| | 31-W-201 | Coal preparation | 1 | 1,096 | |
| | | | | | **1,562** |
| 300 | 31-P-301 | Black Water Pump | 1 | 6 | |
| | 31-P-302 | BFW Pump | 1 | 21 | |
| | 31-P-303 | Grey Water Pump | 1 | 28 | |
| | 31-W-301 | Gasification Package | 1 | 259 | |
| | | | | | **315** |
| 400 | 31-K-401 | Fuel Gas Expander | 1 | -7,149 | |
| | 31-K-402 | Recycle Compressor | 1 | 0 | |
| | 31-K-403 | Selexol N2 Compressor | 1 | 3,672 | |
| | 31-K-404 | N2 Compressor | 1 | 1,886 | |
| | 31-K-405 | Main N2 Compressor | 1 | 27,101 | |
| | 31-P-401 | Desaturator Circulation Pump | 1 | 825 | |
| | 31-P-402 | Low Pressure BFW Pump | 1 | 86 | |
| | 31-P-403 | Intermediate Pressure BFW Pump | 1 | 652 | |
| | 31-P-404 | BFW Circulating Pump | 1 | 85 | |
| | 31-P-405 | High Pressure BFW Pump | 1 | 352 | |
| | 31-P-409 | Process Water Make-up Pump | 1 | 319 | |
| | | | | | **27,828** |
| 500 | 31-P-501 | Lean Solution Pump | 1 | 2,003 | |
| | 31-P-502 | Rich Solution Pump | 1 | 269 | |
| | 31-P-503 | Semi-lean Pump | 5 | 9,521 | |
| | 31-P-504 | Stripper Reflux Pump | 1 | 13 | |
| | 31-P-505 | Loaded Solvent Pump | 1 | 144 | |
| | 31-PT-506 | Rich solvent expander | 5 | -2,787 | |
| | | | | | **9,162** |
| 600 | 31-K-601 | CO2 Compressor | 1 | 25,617 | |
| | 31-P-601 | CO2 Compressor KO Drum Pump | 1 | 2 | |
| | | | | | **25,618** |
| 700 | 31-K-701 | Gas Turbine | 1 | -22,000 | |
| | 31-K-702 | Steam Turbine | 1 | -65,916 | |
| | | Losses GT & ST | | 1,072 | |
| | 31-P-704 | Condensate Pump | 1 | 49 | |
| | | | | | **-86,796** |
| 900 | 31-P-901 | Cooling Water Pump | 2 | 3,392 | |
| | 31-P-902 | Back-up fuel pumps | 2 | 0 | |
| | Misc | | | 2,000 | |
| | | | | | **5,392** |
| | Total Power output (MW) | | | 27.4 | |

**NOTE: All data is for 1 train**

| Issue | A | Date | | Date | | Date | | Date | | Date |
|---|---|---|---|---|---|---|---|---|---|---|
| Description | For Report | | | | | | | | | |
| Made by / Revised by | THLW | 10-mrt-04 | | | | | | | | |
| Checked by | SBJS | 23-mrt-04 | | | | | | | | |
| Approved by | SBJS | | | | | | | | | |

| JACOBS CONSULTANCY | JACOBS CONSULTANCY UK LTD | Document No. 60-8389-00/P.03/3200/A4 |
|---|---|---|
| | Power schedule | PLANT: CO2 Capture Study Case 3-2 |
| | | LOCATION: NE Netherlands |
| | | CLIENT: IEA |
| | | PROJECT: 608389 |



Revised this issue ↓

| | Item no. | Item Name | no. operating | Power (kW) Each | Total | |
|---|---|---|---|---|---|---|
| 100 | 32-W-101 | Air Separation Unit | 1 | | 48,179 | |
| | | | | | | 48,179 |
| 200 | 32-P-201 | Coal Slurry Feed Pump | 1 | | 487 | |
| | 32-W-201 | Coal preparation | | | 1,223 | |
| | | | | | | 1,710 |
| 300 | 32-P-301 | Black Water Pump | 1 | | 7 | |
| | 32-P-302 | BFW Pump | 1 | | 23 | |
| | 32-P-303 | Grey Water Pump | 1 | | 31 | |
| | 32-W-301 | Gasification Package | 1 | | 289 | |
| | | | | | | 351 |
| 400 | 32-K-401 | Fuel Gas expander | 1 | | -1,211 | |
| | 32-K-402 | Recycle Compressor | 1 | | 752 | |
| | 32-K-403 | Selexol N2 Compressor | 1 | | 3,992 | |
| | 32-K-404 | Nitrogen Compressor | 1 | | 319 | |
| | 32-K-405 | Main N2 Compressor | 1 | | 30,662 | |
| | 32-K-406 | Tail Gas Compressor | 1 | | 964 | |
| | 32-P-401 | Desaturator Circulation Pump | 1 | | 982 | |
| | 32-P-402 | Low Pressure BFW Pump | 1 | | 96 | |
| | 32-P-403 | Intermediate Pressure BFW Pump | 1 | | 599 | |
| | 32-P-404 | BFW Circulating Pump | 1 | | 61 | |
| | 32-P-405 | High Pressure BFW Pump | 1 | | 329 | |
| | 32-P-409 | Process Water Make-up Pump | 1 | | 356 | |
| | | | | | | 37,901 |
| 500 | 32-P-501 | Lean Solution Pump | 1 | | 2,234 | |
| | 32-P-502 | Rich Solution Pump | 1 | | 262 | |
| | 32-P-503 | Semi-lean Pump | 6 | | 10,619 | |
| | 32-P-504 | Stripper Recycle Pump | 1 | | 1 | |
| | 32-P-505 | Loaded Solvent Pump | 1 | | 132 | |
| | 32-PT-506 | Rich solvent expander | 6 | | -3,658 | |
| | | | | | | 9,590 |
| 600 | 32-K-601 | CO2 Compressor | 1 | | 27,854 | |
| | 32-P-601 | CO2 Compressor KO Drum Pump | 1 | | 2 | |
| | | | | | | 27,856 |
| 700 | 32-K-701 | Gas Turbine | 1 | | -44,000 | |
| | 32-K-702 | Steam Turbine | 1 | | -89,451 | |
| | | Losses GT & ST | | | 1,622 | |
| | 32-P-704 | Condensate Pump | 2 | | 130 | |
| | | | | | | -131,699 |
| 900 | 32-P-901 | Cooling Water Pump | 2 | | 3,902 | |
| | 0 | 0 | 0 | | 0 | |
| | Misc | | | | 2,000 | |
| | | | | | | 5,902 |
| | Total Power output (MW) | | | | -0.2 | |

**NOTE: All data is for 1 train**

| Issue | A | Date | | Date | | Date | | Date | | Date |
|---|---|---|---|---|---|---|---|---|---|---|
| Description | For Report | | | | | | | | | |
| Made by / Revised by | THLW | 10-mrt-04 | | | | | | | | |
| Checked by | SBJS | 20-mrt-04 | | | | | | | | |
| Approved by | SBJS | 0-jan-00 | | | | | | | | |

# JACOBS CONSULTANCY UK LTD

## Utility Schedule Case 1

DOCUMENT No: 60-8389-00/P03/1700/A4



**PLANT:** CO2 Capture Study **PROJECT:** 60.8389.00

**CLIENT:** IEA **LOCATION:** NE Netherlands

| Rev. | | PLANT SECTION | No. Op | Type of Utility | | | | | | | | | | | | | Remarks |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | LP Steam | Condensate | Sea CW | Fresh CW | DMW | BFW | Elec Power | | | |
| | | | | | | | | t/h | t/h | m$^3$/hr | m$^3$/hr | m$^3$/hr | m$^3$/hr | MW | | | |
| | | | | | | | | | | | | | | | | | |
| | 100 | | | | | | | | | | | | | | | | |
| | 200 | | | | | | | | | | | | | | | | |
| | 300 | | | | | | | | | | | | | | | | |
| | 400 | Acid Gas Removal | | | | | | 619.2 | -720.8 | 29430.5 | 960.0 | 17.2 | 101.6 | 11.2 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 500 | | | | | | | | | | | | | | | | |
| | 600 | Product Gas Exports | | | | | | | | 14526.8 | 800.0 | | | 21.7 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 700 | | | | | | | | | | | | | | | | |
| | 800 | | | | | | | | | | | | | | | | |
| | 900 | Offsites & Utilities | | | | | | | | 1840.0 | -1760.0 | | | 5.6 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | | | | | | | | | | | | | | | | | |
| | Total | | | | | | | 619.2 | -720.8 | 45797.2 | 0.0 | 17.2 | 101.6 | 38.5 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | | | | | | | | | | | | | | | | | |

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | THLW | 18/3/04 | SBJS | 22/3/04 | SBJS | 25/3/04 | For Final Report |
| 1 | THLW | 30/4/04 | SBJS | 30/4/04 | SBJS | 30/4/04 | Including case 1 |
| 2 | THLW | 4/5/04 | SBJS | 4/5/04 | SBJS | 4/5/04 | revised |
| | | | | | | | |

# JACOBS CONSULTANCY UK LTD

## Utility Schedule Case 2-1

**DOCUMENT No:** 60-8389-00/P03/1700/A4



**PLANT:** CO2 Capture Study **PROJECT:** 60.8389.00

**CLIENT:** IEA **LOCATION:** NE Netherlands

| Rev. | | PLANT SECTION | No. Op | | | HP Steam | MP Steam | LP Steam | Condensate | Sea CW | Fresh CW | DMW | BFW | Elec Power | Oxygen | $N_2$ | Remarks |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | t/h | t/h | t/h | t/h | $m^3$/hr | $m^3$/hr | $m^3$/hr | $m^3$/hr | MW | t/h | t/h | |
| | 100 | Air Compression | | | | | | | | 4076.3 | 400.0 | | | 99.2 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 200 | Reformer | | | | -291.7 | 140.5 | -2.8 | -3.1 | | 40.0 | | 297.6 | 0.1 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 300 | Shift | | | | | | | -70.2 | | 20.0 | | 104.3 | 0.2 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 400 | Acid Gas Removal | | | | | | 110.4 | -110.4 | 6166.7 | 40.0 | 12.9 | | 15.5 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 500 | | | | | | | | | | | | | | | | |
| | 600 | Product Gas Exports | | | | | | | -12.3 | 7173.6 | 200.0 | | | 31.9 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 700 | Power Block | | | | 291.7 | -140.5 | -107.6 | 180.6 | 2364.4 | 40.0 | 189.7 | -401.8 | -41.0 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 800 | | | | | | | | | | | | | | | | |
| | 900 | Offsites & Utilities | | | | | | | 15.4 | 770.0 | -740.0 | -202.6 | | 10.1 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | Total | | | | | 0.0 | 0.0 | 0.0 | 0.0 | 20551.0 | 0.0 | 0.0 | 0.0 | 115.9 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | THLW | 18/3/04 | SBJS | 22/3/04 | SBJS | 25/3/04 | For Final Report |
| 1 | THLW | 30/4/04 | SBJS | 30/4/04 | SBJS | 30/4/04 | Including case 1 |
| 2 | THLW | 4/5/04 | SBJS | 4/5/04 | SBJS | 4/5/04 | revised |

# JACOBS CONSULTANCY UK LTD

## Utility Schedule Case 2-2

DOCUMENT No: 60-8389-00/P03/1700/A4



PLANT: CO2 Capture Study PROJECT: 60.8389.00

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | | PLANT SECTION | No. Op | | | HP Steam | MP Steam | LP Steam | Condensate | Sea CW | Fresh CW | DMW | BFW | Elec Power | Oxygen | $N_2$ | Remarks |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | t/h | t/h | t/h | t/h | $m^3/hr$ | $m^3/hr$ | $m^3/hr$ | $m^3/hr$ | MW | t/h | t/h | |
| | 100 | Air Compression | | | | | | | | 4072.9 | 400.0 | | | 98.4 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 200 | Reformer | | | | -316.0 | 140.4 | -3.1 | -3.4 | | 40.0 | | 322.3 | 0.1 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 300 | Shift | | | | | | | -50.8 | | 20.0 | | | 9.7 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 400 | Acid Gas Removal | | | | | | 19.4 | -19.4 | 6161.5 | 40.0 | 12.9 | | 15.1 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 500 | | | | | | | | | | | | | | | | |
| | 600 | Product Gas Exports | | | | | | | -12.3 | 7167.7 | 200.0 | | | 31.9 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 700 | Power Block | | | | 316.0 | -140.4 | -107.2 | 70.2 | 10702.7 | 40.0 | 109.7 | -322.3 | -69.0 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 800 | | | | | | | | | | | | | | | | |
| | 900 | Offsites & Utilities | | | | | | | 15.7 | 770.0 | -740.0 | -122.6 | | 10.7 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | Total | | | | | 0.0 | 0.0 | -90.9 | 0.0 | 28874.9 | 0.0 | 0.0 | 0.0 | 96.9 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | THLW | 18/3/04 | SBJS | 22/3/04 | SBJS | 25/3/04 | For Final Report |
| 1 | THLW | 30/4/04 | SBJS | 30/4/04 | SBJS | 30/4/04 | Including case 1 |
| 2 | THLW | 4/5/04 | SBJS | 4/5/04 | SBJS | 4/5/04 | revised |

# JACOBS CONSULTANCY UK LTD

## Utility Schedule Case 3-1

DOCUMENT No: 60-8389-00/P03/1700/A4



PLANT: CO2 Capture Study PROJECT: 60.8389.00

CLIENT: IEA LOCATION: NE Netherlands

| Rev. | | PLANT SECTION | No. Op | Type of Utility | | | | | | | | | | | | | Remarks |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | HP Steam | MP Steam | LP Steam | Condensate | Process Conden | Sea CW | Fresh CW | DMW | BFW | Elec Power | Oxygen | $N_2$ | |
| | | | | | t/h | t/h | t/h | t/h | t/h | $m^3/hr$ | $m^3/hr$ | $m^3/hr$ | $m^3/hr$ | MW | t/h | t/h | |
| | 100 | ASU | | | | | | | | 12168 | | | | 88.62 | -229.3 | -691.8 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 200 | Feedstock Preparation | | | | | | | 57.7 | | 300.0 | | | 3.1 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 300 | Gasification Unit | | | | | | | 924.4 | 4718 | 30.0 | 68.4 | -68.4 | 0.6 | 228.5 | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 400 | Gas Treatment unit | | | -218.0 | | -335.5 | | -983.5 | 5304.6 | 620.0 | 490.7 | 68.4 | 55.7 | | 113.265 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 500 | Acid Gas Removal | | | | | -12.0 | | | 6571 | 140.0 | 12.1 | | 18.3 | 0.9 | | |
| | 600 | Product Gas Export | | | | | | | 1.4 | 9725.0 | 200.0 | | | 51.2 | | 578.6 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 700 | Power Block | | | 218.0 | | 347.5 | -565.5 | | 42815.5 | 240.0 | | | -173.6 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 800 | | | | | | | | | | | | | | | | |
| | 900 | Utilities and Offsites | | | | | | 565.5 | | 1730.0 | -1530.0 | -571.2 | | 10.8 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | Total | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 83032.5 | 0.0 | 0.0 | 0.0 | 54.8 | 0.0 | 0.0 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description | Sheet |
|---|---|---|---|---|---|---|---|---|
| 0 | THLW | 18/3/04 | SBJS | 22/3/04 | SBJS | 25/3/04 | For Final Report | 4 |
| 1 | THLW | 30/4/04 | SBJS | 30/4/04 | SBJS | 30/4/04 | Including case 1 | of |
| 2 | THLW | 4/5/04 | SBJS | 4/5/04 | SBJS | 4/5/04 | revised | 5 |

# JACOBS CONSULTANCY UK LTD

## Utility Schedule Case 3-2

**DOCUMENT No:** 60-8389-00/P03/1700/A4



**PLANT:** CO2 Capture Study **PROJECT:** 60.8389.00

**CLIENT:** IEA **LOCATION:** NE Netherlands

| Rev. | | PLANT SECTION | No. Op | | HP Steam | MP Steam | LP Steam | Condensate | Process Conden | Sea CW | Fresh CW | DMW | BFW | Elec Power | Oxygen | $N_2$ | Remarks |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | t/h | t/h | t/h | t/h | t/h | $m^3/hr$ | $m^3/hr$ | $m^3/hr$ | $m^3/hr$ | MW | t/h | t/h | |
| | | | | | | | | | | | | | | | | | |
| | 100 | ASU | | | | | | | | 13572 | | | | 96.36 | -249.4 | -645.8 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 200 | Feedstock Preparation | | | | | | | 64.4 | | 300.0 | | | 3.4 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 300 | Gasification Unit | | | | | | | 1033.9 | 5262 | 30.0 | 76.9 | -76.9 | 0.7 | 248.4 | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 400 | Gas Treatment unit | | | -237.0 | | -465.1 | | -1098.3 | 8427.8 | 420.0 | 632.3 | 76.9 | 75.8 | | 126.332 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 500 | Acid Gas Removal | | | | | -13.4 | | | 7329 | 140.0 | 13.5 | | 19.2 | 1.0 | | |
| | 600 | Product Gas Export | | | | | | | 1.5 | 1906.8 | 200.0 | | | 55.7 | | 519.5 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 700 | Power Block | | | 237.0 | | 478.5 | -715.5 | | 57486.9 | 240.0 | | | -263.4 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | 800 | | | | | | | | | | | | | | | | |
| | 900 | Utilities and Offsites | | | | | | 715.5 | | 1530.0 | -1330.0 | -722.7 | | 11.8 | | | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | | | | | | | | | | | | | | | | | |
| | Total | | | | 0.0 | 0.0 | 0.0 | 0.0 | 1.5 | 95515 | 0.0 | 0.0 | 0.0 | -0.4 | 0.0 | 0.0 | NEGATIVE VALUE IMPLIES UTILITY GENERATION |
| | | | | | | | | | | | | | | | | | |

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | THLW | 18/3/04 | SBJS | 22/3/04 | SBJS | 25/3/04 | For Final Report |
| 1 | THLW | 30/4/04 | SBJS | 30/4/04 | SBJS | 30/4/04 | Including case 1 |
| 2 | THLW | 4/5/04 | SBJS | 4/5/04 | SBJS | 4/5/04 | revised |

# Appendix 6

Fuel/$CO_2$ Capture Plants Capital Cost Estimates

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

## Capital Cost Estimate Case 1

DOCUMENT No: 60-8389-00/P03/1200/A4



PLANT: Capture Plant Case 1 PROJECT: 60.8389.00

CLIENT: IEA GHG LOCATION: NE Netherlands

| | Direct Materials | Construction | Engineering and Construction Services | Total | |
|---|---|---|---|---|---|
| | | | | | (*1000,000) |
| Acid Gas Removal | 201.72 | 37.25 | 26.51 | 265.47 | US $ |
| CO2 Compression & drying | 15.91 | 3.92 | 10.33 | 30.15 | US $ |
| Offsites & Utilities | 19.00 | 8.40 | 14.62 | 42.02 | US $ |
| Total | 235.70 | 49.57 | 51.45 | 337.65 | US $ |
| Contingency | | | | 33.76 | US $ |
| Owners costs | | | | 23.64 | US $ |
| Total Installed costs | | | | 395.05 | US $ |

Original estimates are 100% in US $

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | SBJS | 19-apr-04 | AH | 19-apr-04 | SBJS | 19-apr-04 | For report |
| 1 | SBJS | 05-mei-04 | AH | 05-mei-04 | SBJS | 05-mei-04 | Inc case 1 & revised case 2 |
| 2 | IJJ | 05-mei-04 | | | KOMI | 07-mei-04 | For Final Report |
| 3 | IJJ | 26 July 2004 | | | KOMI | 26 July 2004 | For Final Report |

# JACOBS CONSULTANCY UK LTD

## Capital Cost Estimate Case 2-1

DOCUMENT No: 60-8389-00/P03/1200/A4



**PLANT:** Capture Plant Case 2-1 **PROJECT:** 60.8389.00

**CLIENT:** IEA GHG **LOCATION:** NE Netherlands

| Plant Section | Direct Materials | Construction | Engineering and Construction Services | Total | (*1000,000) |
|---|---|---|---|---|---|
| Air Compression | 53.32 | 13.15 | 34.62 | 101.09 | US $ |
| Reforming & HT Cooling | 27.89 | 8.04 | 12.82 | 48.75 | US $ |
| Shift & LT Cooling | 24.73 | 6.65 | 8.96 | 40.34 | US $ |
| Acid Gas Removal | 50.64 | 21.57 | 45.77 | 117.99 | US $ |
| CO2 Compression & drying | 19.55 | 4.82 | 12.69 | 37.06 | US $ |
| Power Generation | 40.63 | 3.63 | 17.27 | 61.54 | US $ |
| Offsites & Utilities* | 43.81 | 15.50 | 20.34 | 79.64 | US $ |
| Total | 260.58 | 73.36 | 152.47 | 486.40 | US $ |
| Contingency | | | | 48.64 | US $ |
| Owners costs | | | | 34.05 | US $ |
| Total Installed costs | | | | 569.09 | US $ |

| ***Offsites & Utilities include:** | (*1000,000) US $ |
|---|---|
| Replace GT combustion chambers | 16.53 |
| Extension demin water plant | 3.69 |
| Cooling water intake/outfall | 0.37 |

Original estimates are 2.3% in US $ and 97.7% in € (€/US $ = 1.23)

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | SBJS | 19-apr-04 | AH | 19-apr-04 | SBJS | 19-apr-04 | For report |
| 1 | SBJS | 05-mei-04 | AH | 05-mei-04 | SBJS | 05-mei-04 | Inc case 1 & revised case 2 |
| 2 | IJJ | 07-05-04 | KOMI | 07-05-04 | KOMI | 38114 | For Final Report |
| 3 | IJJ | 26 July 2004 | | | KOMI | 26 July 2004 | For Final Report |

JACOBS CONSULTANCY

# JACOBS CONSULTANCY UK LTD

## Capital Cost Estimate Case 2-2

DOCUMENT No: 60-8389-00/P03/1200/A4



**PLANT:** Capture Plant Case 2-2 **PROJECT:** 60.8389.00

**CLIENT:** IEA GHG **LOCATION:** NE Netherlands

| Plant Section | Direct Materials | Construction | Engineering and Construction Services | Total | (*1000,000) |
|---|---|---|---|---|---|
| Air Compression | 53.32 | 13.15 | 34.62 | 101.09 | US $ |
| Reforming & HT Cooling | 27.89 | 8.04 | 12.82 | 48.75 | US $ |
| Shift & LT Cooling | 24.73 | 10.22 | 27.02 | 61.97 | US $ |
| Acid Gas Removal | 50.64 | 21.57 | 45.77 | 117.99 | US $ |
| CO2 Compression & drying | 19.55 | 4.82 | 12.69 | 37.06 | US $ |
| Power Generation | 57.75 | 5.16 | 24.55 | 87.46 | US $ |
| Offsites & Utilities* | 97.13 | 47.18 | 42.63 | 186.93 | US $ |
| Total | 331.02 | 110.14 | 200.10 | 641.24 | US $ |
| Contingency | | | | 64.12 | US $ |
| Owners costs | | | | 44.89 | US $ |
| | | | | | US $ |
| Total Installed costs | | | | 750.25 | US $ |

| *Offsites & Utilities include: | (*1000,000) US $ |
|---|---|
| Replace GT combustion chambers | 16.53 |
| Extension demin water plant | 6.15 |
| Cooling water intake/outfall | 0.49 |
| Long Distance Fuel Piping | 99.38 |

Original estimates are 7% in US $ and 93% in € (€/US $ = 1.23)

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | SBJS | 19-apr-04 | AH | 19-apr-04 | SBJS | 19-apr-04 | For report |
| 1 | SBJS | 05-mei-04 | AH | 05-mei-04 | SBJS | 05-mei-04 | Inc case 1 & revised case 2 |
| 2 | IJJ | 07-05-04 | KOMI | 07-05-04 | KOMI | 07-05-04 | For Final Report |
| 3 | IJJ | 26 July 2004 | | | KOMI | 26 July 2004 | For Final Report |

# JACOBS CONSULTANCY UK LTD

JACOBS CONSULTANCY

## Capital Cost Estimate Case 3-1

DOCUMENT No: 60-8389-00/P03/1200/A4



PLANT: Capture Plant Case 3-1 PROJECT: 60.8389.00

CLIENT: IEA GHG LOCATION: NE Netherlands

| Plant Section | Direct Materials | Construction | Engineering and Construction Services | Total | (*1000,000) |
|---|---|---|---|---|---|
| ASU | 96.52 | 23.81 | 62.66 | 182.98 | US $ |
| Coal Receiving, grinding and slurry prep | 20.33 | 10.94 | 21.03 | 52.30 | US $ |
| Gasification Unit | 109.27 | 33.50 | 60.43 | 203.20 | US $ |
| Gas Treatment Package | 35.74 | 7.27 | 20.98 | 63.99 | US $ |
| Acid Gas Removal | 24.84 | 10.58 | 22.45 | 57.87 | US $ |
| CO2 Compression & drying | 28.83 | 7.11 | 18.71 | 54.65 | US $ |
| Combined Cycle Unit | 52.49 | 4.69 | 22.31 | 79.50 | US $ |
| Offsites & Utilities* | 62.31 | 26.44 | 39.13 | 127.88 | US $ |
| Total | 430.33 | 124.33 | 267.71 | 822.38 | US $ |
| Contingency | | | | 82.24 | US $ |
| Owners costs | | | | 57.57 | US $ |
| Total Installed costs | | | | 962.18 | US $ |

| ***Offsites & Utilities include:** | (*1000,000) US $ |
|---|---|
| Replace GT combustion chambers | 16.53 |
| Extension demin water plant | 3.69 |
| Cooling water intake/outfall | 1.10 |

Original estimates are 51% in US $, 4% in £ and 45% in € (€/US $ = 1.23, £/US $ = 1.74)

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | SBJS | 19-apr-04 | AH | 19-apr-04 | SBJS | 19-apr-04 | For report |
| 1 | SBJS | 05-mei-04 | AH | 05-mei-04 | SBJS | 05-mei-04 | Inc case 1 & revised case 2 |
| 2 | IJJ | 07-05-04 | KOMI | 07-05-04 | KOMI | 07-05-04 | For final report |
| 3 | IJJ | 26 July 2004 | | | KOMI | 26 July 2004 | For Final Report |

# JACOBS CONSULTANCY UK LTD

## Capital Cost Estimate Case 3-2

DOCUMENT No: 60-8389-00/P03/1200/A4



PLANT: Capture Plant Case 3-2 PROJECT: 60.8389.00

CLIENT: IEA GHG LOCATION: NE Netherlands

| Plant Section | Direct Materials | Construction | Engineering and Construction Services | Total | (*1000,000) |
|---|---|---|---|---|---|
| ASU | 102.35 | 25.24 | 66.44 | 194.03 | US $ |
| Coal Receiving, grinding and slurry prep | 20.16 | 10.84 | 20.86 | 51.86 | US $ |
| Gasification Unit | 107.80 | 33.05 | 59.61 | 200.47 | US $ |
| Gas Treatment Package | 50.46 | 10.26 | 29.62 | 90.34 | US $ |
| Acid Gas Removal | 24.51 | 10.44 | 22.15 | 57.10 | US $ |
| CO2 Compression & drying | 30.57 | 7.54 | 19.84 | 57.95 | US $ |
| Combined Cycle Unit | 92.60 | 8.28 | 39.36 | 140.24 | US $ |
| Offsites & Utilities* | 111.91 | 55.58 | 61.20 | 228.69 | US $ |
| Total | 540.34 | 161.23 | 319.09 | 1020.66 | US $ |
| Contingency | | | | 102.07 | US $ |
| Owners costs | | | | 71.45 | US $ |
| Total Installed costs | | | | 1194.18 | US $ |

| *Offsites & Utilities include: | (*1000,000) US $ |
|---|---|
| Replace GT combustion chambers | 16.53 |
| Extension demin water plant | 6.15 |
| Cooling water intake/outfall | 1.23 |
| Long Distance Fuel Piping | 86.34 |

Original estimates are 50% in US $, 9% in £ and 41% in € (€/US $ = 1.23, £/US $ = 1.74)

Notes

| Rev. | Made by | Date | Checked by | Date | Approved by | Date | Description |
|---|---|---|---|---|---|---|---|
| 0 | SBJS | 19-apr-04 | AH | 19-apr-04 | SBJS | 19-apr-04 | For report |
| 1 | SBJS | 05-mei-04 | AH | 05-mei-04 | SBJS | 05-mei-04 | Inc case 1 & revised case 2 |
| 2 | IJJ | 07-05-04 | KOMI | 07-05-04 | KOMI | 07-05-04 | For Final Report |
| 3 | IJJ | 26 July 2004 | | | KOMI | 26 July 2004 | For Final Report |

# Appendix 7

Cash Flow Calculations

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Reference CASE**

30 jul 2004 11:04

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 100 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 132.9 | 132.9 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 203.6 | 203.6 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 203.562 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 64.49% | |
| Capital | 26.31% | |
| Other costs | 9.20% | |

### CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | |
| Maintenance | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| Labour | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | |
| Chemicals & consumables | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 0.2 |
| Total Cash Flow (cumulated) | 158.5 | 207.5 | 256.5 | 305.5 | 354.5 | 403.5 | 452.5 | 501.5 | 550.5 | 599.4 | 648.4 | 697.4 | 746.4 | 795.4 | 795.6 |

Version 4.5
Date : July 2004

# IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 1**

30 jul 2004 11:04

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 132.9 | 132.9 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 73.2 | 73.2 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 73.241 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 57.14% | |
| Capital | 32.30% | |
| Other costs | 10.56% | |

## CASH FLOW ANALYSIS

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 110.9 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 83.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -89.7 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -10.4 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.8 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -1.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -13.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -158.0 | -237.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -109.0 | -192.8 | 76.4 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -146.5 | -339.3 | -262.9 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | |
| CO2 revenues(based on power output retrofit case) | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | 110.7 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | |
| Maintenance | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| Labour | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | |
| Chemicals & consumables | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | |
| Waste disposal | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | |
| Insurance and local taxes | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 0.4 |
| Total Cash Flow (cumulated) | -155.6 | -48.3 | 59.1 | 166.4 | 273.7 | 381.0 | 488.4 | 595.7 | 703.0 | 810.4 | 917.7 | 1025.0 | 1132.4 | 1239.7 | 1240.1 |

| | | | |
|---|---|---|---|
| **IEA GREENHOUSE GAS R&D PROGRAMME** | Cost Evaluation - CASE 2.1 | Version | 4.5 |
| 30 jul 2004 11:04 | | Date | : July 2004 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 1672.4 | MW |
| Net power output | 784.8 | 693.7 | MW |
| CO2 output | 293.0 | 50.1 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 72 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 486.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 48.6 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 34.0 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **569.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 132.9 | 158.2 |
| Maintenance | 7.9 | 18.7 |
| Chemicals + consumables | 1.7 | 11.1 |
| Insurance and local taxes | 7.1 | 16.8 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 2.3 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 95.0 | 95.0 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 20 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 95.049 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 55.37% | |
| Capital | 32.96% | |
| Other costs | 11.67% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 122.9 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 117.4 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -106.8 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -12.6 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -2.3 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -7.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -16.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -227.6 | -341.5 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -178.6 | -297.2 | 93.2 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -216.1 | -513.4 | -420.1 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | |
| CO2 revenues(based on power output retrofit case) | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | 156.5 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | |
| Maintenance | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| Labour | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Chemicals & consumables | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 1.2 |
| Total Cash Flow (cumulated) | -288.1 | -156.0 | -24.0 | 108.1 | 240.1 | 372.1 | 504.2 | 636.2 | 768.3 | 900.3 | 1032.4 | 1164.4 | 1296.5 | 1428.5 | 1429.7 |

Version 4.5
Date : July 2004

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 2.2**

30 jul 2004 11:04

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 1671.0 | MW |
| Net power output | 784.8 | 667.4 | MW |
| CO2 output | 293.0 | 49.9 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 75 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 641.2 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 64.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 44.9 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **750.3** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 132.9 | 158.1 |
| Maintenance | 7.9 | 22.1 |
| Chemicals + consumables | 1.7 | 10.7 |
| Insurance and local taxes | 7.1 | 19.9 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 124.3 | 124.3 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 124.335 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 52.90% | |
| Capital | 34.97% | |
| Other costs | 12.13% | |

### CASH FLOW ANALYSIS

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 118.3 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 146.5 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -106.7 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.9 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -7.2 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -19.9 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -300.1 | -450.2 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -251.1 | -405.9 | 111.4 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -288.6 | -694.5 | -583.1 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | |
| CO2 revenues(based on power output retrofit case) | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | 195.3 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | |
| Maintenance | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 1.1 |
| Total Cash Flow (cumulated) | -425.4 | -267.7 | -110.0 | 47.7 | 205.5 | 363.2 | 520.9 | 678.6 | 836.3 | 994.0 | 1151.7 | 1309.4 | 1467.1 | 1624.8 | 1626.0 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 3.1**

30 jul 2004 11:04

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2121.2 | MW |
| Net power output | 784.8 | 751.2 | MW |
| CO2 output | 293.0 | 97.6 | t/h |
| Solid waste output | 0.00 | 1.70 | t/h |
| CO2 emissions | 373 | 130 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 822.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 82.2 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 57.6 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **962.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.4 |
| Fuel storage | 0.0 | 9.7 |
| **Total working capital** | **0.2** | **10.1** |

| **Operating Costs** | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| **at 100% load factor** | | |
| Fuel | 132.9 | 100.3 |
| Maintenance | 7.9 | 31.8 |
| Chemicals + consumables | 1.7 | 4.6 |
| Insurance and local taxes | 7.1 | 23.5 |
| Waste disposal | 0.0 | 2.7 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 131.4 | 131.4 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 131.365 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 45.84% | |
| Capital | 40.85% | |
| Other costs | 13.31% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 88.8 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 94.7 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -45.2 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -2.1 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.2 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -23.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -192.4 | -433.0 | -336.8 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -10.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -143.4 | -384.0 | -292.5 | 83.5 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -229.9 | -613.9 | -906.5 | -823.0 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | |
| CO2 revenues(based on power output retrofit case) | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | 178.9 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | |
| Maintenance | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | |
| Waste disposal | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Insurance and local taxes | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.3 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 200.9 | 10.3 |
| Total Cash Flow (cumulated) | -622.1 | -421.2 | -220.4 | -19.5 | 181.4 | 382.2 | 583.1 | 784.0 | 984.9 | 1185.7 | 1386.6 | 1587.5 | 1788.4 | 1989.2 | 1999.5 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

# IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 3.2**

30 jul 2004 11:04

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2306.4 | MW |
| Net power output | 784.8 | 774.6 | MW |
| CO2 output | 293.0 | 108.5 | t/h |
| Solid waste output | 0.00 | 1.84 | t/h |
| CO2 emissions | 373 | 140 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 1020.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 102.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 71.4 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1194.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 10.5 |
| **Total working capital** | **0.2** | **11.1** |

| **Operating Costs at 100% load factor** | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 109.1 |
| Maintenance | 7.9 | 36.2 |
| Chemicals + consumables | 1.7 | 5.2 |
| Insurance and local taxes | 7.1 | 27.5 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 4.7 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 168.1 | 168.1 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 40 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 168.131 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 43.75% | |
| Capital | 42.59% | |
| Other costs | 13.66% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 91.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 119.7 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -49.1 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -16.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -4.7 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -2.3 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.3 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -27.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -238.8 | -537.4 | -418.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -11.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -189.8 | -488.4 | -373.7 | 99.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -276.3 | -764.7 | -1138.5 | -1039.5 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | |
| CO2 revenues(based on power output retrofit case) | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | 226.1 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | |
| Maintenance | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | |
| Labour | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | |
| Chemicals & consumables | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | |
| Waste disposal | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | |
| Insurance and local taxes | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 236.4 | 11.2 |
| Total Cash Flow (cumulated) | -803.1 | -566.7 | -330.3 | -93.9 | 142.5 | 378.9 | 615.3 | 851.7 | 1088.1 | 1324.5 | 1560.9 | 1797.3 | 2033.7 | 2270.0 | 2281.3 |

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Date : July 2004

**IEA GREENHOUSE GAS R&D PROGRAMME**

**Cost Evaluation - Reference CASE fuelprice +100%**

30 jul 2004 11:04

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 4.931 | | c/kWh |
| | | | |
| Retrofit year (n) | | 100 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 265.8 | 265.8 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 6.00 | 6.00 | $/GJ |
| CO2 price | 203.6 | 203.6 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 203.562 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 78.40% | |
| Capital | 15.99% | |
| Other costs | 5.61% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 228.8 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -179.4 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | |
| Maintenance | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| Labour | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | |
| Chemicals & consumables | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 0.2 |
| Total Cash Flow (cumulated) | 158.5 | 207.5 | 256.5 | 305.5 | 354.5 | 403.5 | 452.5 | 501.5 | 550.5 | 599.5 | 648.5 | 697.4 | 746.4 | 795.4 | 795.6 |

Version 4.5
Date : July 2004

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Sensitivity fuelprice +100% CASE 1**

30 jul 2004 11:04

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| $CO_2$ output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| $CO_2$ emissions | 373 | 67 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| $CO_2$ emissions | 373 | | g/kWh |
| Electricity cost | 4.931 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 265.8 | 265.8 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 6.00 | 6.00 | $/GJ |
| $CO_2$ price | 89.3 | 89.3 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

**Results summary**

| | | |
|---|---|---|
| Emission avoidance cost | 89.269 | $/t $CO_2$ |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the $CO_2$ emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |

**Breakdown of c/kWh cost**

| | |
|---|---|
| Fuel | 72.71% |
| Capital | 20.55% |
| Other costs | 6.73% |

**CASH FLOW ANALYSIS**

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 228.8 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 279.7 | 182.5 |
| $CO_2$ revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 101.2 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -179.4 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -219.3 | -179.4 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -10.4 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.8 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -1.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -13.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -158.0 | -237.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -109.0 | -192.8 | 76.4 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -146.5 | -339.3 | -263.0 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | 243.3 | |
| $CO_2$ revenues(based on power output retrofit case) | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | 134.9 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | |
| Maintenance | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| Labour | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | |
| Chemicals & consumables | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | |
| Waste disposal | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | |
| Insurance and local taxes | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 0.4 |
| Total Cash Flow (cumulated) | -155.6 | -48.3 | 59.0 | 166.4 | 273.7 | 381.1 | 488.4 | 595.7 | 703.1 | 810.4 | 917.7 | 1025.1 | 1132.4 | 1239.7 | 1240.1 |

| | | |
|---|---|---|
| | Version | 4.5 |
| | Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Sensitivity fuelprice +100% CASE 2.1**

30 jul 2004 11:04

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1672.4 | MW |
| Net power output | 784.8 | 693.7 | MW |
| CO2 output | 293.0 | 50.1 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 72 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 4.931 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 486.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 48.6 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 34.0 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **569.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 265.8 | 316.4 |
| Maintenance | 7.9 | 18.7 |
| Chemicals + consumables | 1.7 | 11.2 |
| Insurance and local taxes | 7.1 | 16.8 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 2.3 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 6.00 | 6.00 | $/GJ |
| CO2 price | 117.3 | 117.3 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 20 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| Results summary | | |
|---|---|---|
| Emission avoidance cost | 117.335 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 71.26% | |
| Capital | 21.21% | |
| Other costs | 7.53% | |

### CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 228.8 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 279.7 | 202.3 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 144.9 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -179.4 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -219.3 | -213.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -12.6 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -2.3 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -7.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -16.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -227.6 | -341.5 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -178.6 | -297.2 | 93.2 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -216.1 | -513.4 | -420.1 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | 269.7 | |
| CO2 revenues(based on power output retrofit case) | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | -284.8 | |
| Maintenance | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| Labour | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Chemicals & consumables | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 1.2 |
| Total Cash Flow (cumulated) | -288.1 | -156.0 | -24.0 | 108.1 | 240.1 | 372.1 | 504.2 | 636.2 | 768.3 | 900.3 | 1032.4 | 1164.4 | 1296.5 | 1428.5 | 1429.7 |

| | |
|---|---|
| | Version | 4.5 |
| | Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Sensitivity fuelprice +100% CASE 2.2**

30 jul 2004 11:04

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1671.0 | MW |
| Net power output | 784.8 | 667.4 | MW |
| CO2 output | 293.0 | 49.9 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 75 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 4.931 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 641.2 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 64.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 44.9 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **750.3** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| **Operating Costs** **at 100% load factor** | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 265.8 | 316.2 |
| Maintenance | 7.9 | 22.1 |
| Chemicals + consumables | 1.7 | 10.8 |
| Insurance and local taxes | 7.1 | 19.9 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 6.00 | 6.00 | $/GJ |
| CO2 price | 150.2 | 150.2 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 150.172 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 69.18% | |
| Capital | 22.87% | |
| Other costs | 7.95% | |

### CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 228.8 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 279.7 | 194.6 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 176.9 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -179.4 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -219.3 | -213.4 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.9 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -7.3 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -19.9 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -300.1 | -450.2 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -251.1 | -405.9 | 111.4 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -288.6 | -694.5 | -583.1 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | 259.5 | |
| CO2 revenues(based on power output retrofit case) | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | -284.6 | |
| Maintenance | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 1.1 |
| Total Cash Flow (cumulated) | -425.4 | -267.7 | -110.0 | 47.7 | 205.5 | 363.2 | 520.9 | 678.6 | 836.3 | 994.0 | 1151.7 | 1309.4 | 1467.1 | 1624.8 | 1626.0 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Sensitivity fuelprice +100% CASE 3.1**

30 jul 2004 11:04

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2121.2 | MW |
| Net power output | 784.8 | 751.2 | MW |
| CO2 output | 293.0 | 97.6 | t/h |
| Solid waste output | 0.00 | 1.70 | t/h |
| CO2 emissions | 373 | 130 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 4.931 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 822.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 82.2 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 57.6 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **962.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 19.4 |
| **Total working capital** | **0.2** | **19.9** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 265.8 | 200.7 |
| Maintenance | 7.9 | 31.8 |
| Chemicals + consumables | 1.7 | 4.7 |
| Insurance and local taxes | 7.1 | 23.5 |
| Waste disposal | 0.0 | 2.7 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 6.00 | 3.00 | $/GJ |
| CO2 price | 115.3 | 115.3 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 115.288 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 62.80% | |
| Capital | 28.07% | |
| Other costs | 9.13% | |

### CASH FLOW ANALYSIS

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 228.8 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 279.7 | 146.0 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 83.1 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -179.4 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -219.3 | -90.3 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -2.1 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.2 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -23.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -192.4 | -433.0 | -336.8 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -19.9 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -143.4 | -384.0 | -292.5 | 74.3 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -229.9 | -613.9 | -906.5 | -832.2 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | 275.8 | |
| CO2 revenues(based on power output retrofit case) | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | 157.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | -170.6 | |
| Maintenance | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | |
| Waste disposal | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Insurance and local taxes | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 201.8 | 20.0 |
| Total Cash Flow (cumulated) | -630.4 | -428.6 | -226.8 | -25.0 | 176.8 | 378.6 | 580.5 | 782.3 | 984.1 | 1185.9 | 1387.7 | 1589.5 | 1791.3 | 1993.1 | 2013.1 |

| | | | |
|---|---|---|---|
| | | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - Sensitivity fuelprice +100% CASE 3.2** | Date | : July 2004 |
| 30 jul 2004 11:04 | | | |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 2306.4 | MW |
| Net power output | 784.8 | 774.6 | MW |
| CO2 output | 293.0 | 108.5 | t/h |
| Solid waste output | 0.00 | 1.84 | t/h |
| CO2 emissions | 373 | 140 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 4.931 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 1020.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 102.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 71.4 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1194.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 21.1 |
| **Total working capital** | **0.2** | **21.6** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 265.8 | 218.2 |
| Maintenance | 7.9 | 36.2 |
| Chemicals + consumables | 1.7 | 5.3 |
| Insurance and local taxes | 7.1 | 27.5 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 4.7 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 6.00 | 3.00 | $/GJ |
| CO2 price | 154.9 | 154.9 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 40 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 154.947 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 60.80% | |
| Capital | 29.69% | |
| Other costs | 9.51% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 228.8 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 305.1 | 279.7 | 150.6 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 110.3 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -179.4 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -239.2 | -219.3 | -98.2 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -16.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -4.7 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -2.4 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.3 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -27.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -238.8 | -537.4 | -418.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -21.6 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -189.8 | -488.4 | -373.7 | 88.9 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -276.3 | -764.7 | -1138.5 | -1049.5 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | 284.4 | |
| CO2 revenues(based on power output retrofit case) | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | -185.5 | |
| Maintenance | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | |
| Labour | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | |
| Chemicals & consumables | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | |
| Waste disposal | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | |
| Insurance and local taxes | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 21.8 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 237.4 | 21.8 |
| Total Cash Flow (cumulated) | -812.1 | -574.7 | -337.3 | -99.9 | 137.6 | 375.0 | 612.4 | 849.8 | 1087.2 | 1324.6 | 1562.0 | 1799.4 | 2036.9 | 2274.3 | 2296.0 |

| | | |
|---|---|---|
| | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | Date | : July 2004 |

**Cost Evaluation - Reference CASE fuelprice -50%**

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| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.031 | | c/kWh |
| Retrofit year (n) | | 100 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 66.4 | 66.4 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 1.50 | 1.50 | $/GJ |
| CO2 price | 203.6 | 203.6 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 203.562 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 47.59% | |
| Capital | 38.82% | |
| Other costs | 13.59% | |

CASH FLOW ANALYSIS

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 94.2 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -44.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | |
| Maintenance | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| Labour | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | |
| Chemicals & consumables | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 0.2 |
| Total Cash Flow (cumulated) | 158.5 | 207.5 | 256.5 | 305.5 | 354.5 | 403.5 | 452.5 | 501.5 | 550.5 | 599.4 | 648.4 | 697.4 | 746.4 | 795.4 | 795.6 |

| | | |
|---|---|---|
| | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | Date | : July 2004 |

**Cost Evaluation - Sensitivity fuelprice -50% CASE 1**

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| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.031 | | c/kWh |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 66.4 | 66.4 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 1.50 | 1.50 | $/GJ |
| CO2 price | 65.2 | 65.2 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| Results summary | | |
|---|---|---|
| Emission avoidance cost | 65.231 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 40.00% | |
| Capital | 45.22% | |
| Other costs | 14.78% | |

CASE FLOW ANALYSIS

| CASH FLOW ANALYSIS Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 94.2 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 115.2 | 75.2 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 74.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -44.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -54.8 | -44.8 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -10.4 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.8 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -1.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -13.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -158.0 | -237.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -109.0 | -192.8 | 76.4 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -146.5 | -339.3 | -262.9 |

| CASH FLOW ANALYSIS Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | 100.2 | |
| CO2 revenues(based on power output retrofit case) | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | |
| Maintenance | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| Labour | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | |
| Chemicals & consumables | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | |
| Waste disposal | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | |
| Insurance and local taxes | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 107.3 | 0.4 |
| Total Cash Flow (cumulated) | -155.6 | -48.3 | 59.1 | 166.4 | 273.7 | 381.0 | 488.4 | 595.7 | 703.0 | 810.4 | 917.7 | 1025.0 | 1132.4 | 1239.7 | 1240.1 |

| | | | |
|---|---|---|---|
| | | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - Sensitivity fuelprice -50% CASE 2.1** | Date | : July 2004 |

30 jul 2004 11:04

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1672.4 | MW |
| Net power output | 784.8 | 693.7 | MW |
| $CO_2$ output | 293.0 | 50.1 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| $CO_2$ emissions | 373 | 72 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| $CO_2$ emissions | 373 | | g/kWh |
| Electricity cost | 2.031 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 486.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 48.6 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 34.0 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **569.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| **Operating Costs at 100% load factor** | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 66.4 | 79.1 |
| Maintenance | 7.9 | 18.7 |
| Chemicals + consumables | 1.7 | 11.1 |
| Insurance and local taxes | 7.1 | 16.8 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 2.3 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 1.50 | 1.50 | $/GJ |
| $CO_2$ price | 83.9 | 83.9 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 20 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 83.908 | $/t $CO_2$ |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the $CO_2$ emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 38.28% | |
| Capital | 45.58% | |
| Other costs | 16.14% | |

CASH FLOW ANALYSIS

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 94.2 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 115.2 | 83.3 |
| $CO_2$ revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 103.6 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -44.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -54.8 | -53.4 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -12.6 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -2.3 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -7.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -16.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -227.6 | -341.5 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -178.6 | -297.2 | 93.2 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -216.1 | -513.4 | -420.1 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | 111.1 | |
| $CO_2$ revenues(based on power output retrofit case) | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | 138.2 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | -71.2 | |
| Maintenance | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| Labour | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Chemicals & consumables | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 132.0 | 1.2 |
| Total Cash Flow (cumulated) | -288.1 | -156.0 | -24.0 | 108.1 | 240.1 | 372.1 | 504.2 | 636.2 | 768.3 | 900.3 | 1032.4 | 1164.4 | 1296.5 | 1428.5 | 1429.7 |

| | | | |
|---|---|---|---|
| | | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - Sensitivity fuelprice -50% CASE 2.2** | Date | : July 2004 |

30 jul 2004 11:04

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1671.0 | MW |
| Net power output | 784.8 | 667.4 | MW |
| CO2 output | 293.0 | 49.9 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 75 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.031 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | REFEREN **Million $** | RETROFIT **Million $** |
|---|---|---|
| Installed costs | 354.7 | 641.2 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 64.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 44.9 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **750.3** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| **Operating Costs** **at 100% load factor** | REFEREN **MM $/year** | RETROFIT **MM $/year** |
|---|---|---|
| Fuel | 66.4 | 79.0 |
| Maintenance | 7.9 | 22.1 |
| Chemicals + consumables | 1.7 | 10.7 |
| Insurance and local taxes | 7.1 | 19.9 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 1.50 | 1.50 | $/GJ |
| CO2 price | 111.4 | 111.4 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 111.419 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 35.96% | |
| Capital | 47.54% | |
| Other costs | 16.49% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 94.2 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 115.2 | 80.1 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 131.3 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -44.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -54.8 | -53.4 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.9 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -7.2 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -19.9 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -300.1 | -450.2 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -251.1 | -405.9 | 111.4 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -288.6 | -694.5 | -583.1 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | 106.9 | |
| CO2 revenues(based on power output retrofit case) | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | -71.1 | |
| Maintenance | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 1.1 |
| Total Cash Flow (cumulated) | -425.4 | -267.7 | -110.0 | 47.7 | 205.5 | 363.2 | 520.9 | 678.6 | 836.3 | 994.0 | 1151.7 | 1309.4 | 1467.1 | 1624.8 | 1626.0 |

| | | |
|---|---|---|
| | Version | 4.5 |
| | Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Sensitivity fuelprice -50% CASE 3.1**

30 jul 2004 11:04

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2121.2 | MW |
| Net power output | 784.8 | 751.2 | MW |
| $CO_2$ output | 293.0 | 97.6 | t/h |
| Solid waste output | 0.00 | 1.70 | t/h |
| $CO_2$ emissions | 373 | 130 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| $CO_2$ emissions | 373 | | g/kWh |
| Electricity cost | 2.031 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 822.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 82.2 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 57.6 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **962.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.4 |
| Fuel storage | 0.0 | 4.9 |
| **Total working capital** | **0.2** | **5.3** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 66.4 | 50.2 |
| Maintenance | 7.9 | 31.8 |
| Chemicals + consumables | 1.7 | 4.6 |
| Insurance and local taxes | 7.1 | 23.5 |
| Waste disposal | 0.0 | 2.7 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 1.50 | 0.75 | $/GJ |
| $CO_2$ price | 139.4 | 139.4 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

**Results summary**

| | | |
|---|---|---|
| Emission avoidance cost | 139.405 | $/t $CO_2$ |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the $CO_2$ emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |

**Breakdown of c/kWh cost**

| | |
|---|---|
| Fuel | 29.76% |
| Capital | 52.96% |
| Other costs | 17.28% |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 94.2 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 115.2 | 60.1 |
| $CO_2$ revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 100.5 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -44.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -54.8 | -22.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -2.1 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.2 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -23.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -192.4 | -433.0 | -336.8 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -5.3 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -143.4 | -384.0 | -292.5 | 88.1 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -229.9 | -613.9 | -906.5 | -818.4 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | 113.6 | |
| $CO_2$ revenues(based on power output retrofit case) | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | 189.8 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | -42.6 | |
| Maintenance | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | |
| Waste disposal | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Insurance and local taxes | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 200.4 | 5.4 |
| Total Cash Flow (cumulated) | -618.0 | -417.6 | -217.2 | -16.8 | 183.6 | 384.0 | 584.4 | 784.9 | 985.3 | 1185.7 | 1386.1 | 1586.5 | 1786.9 | 1987.3 | 1992.7 |

| | | | |
|---|---|---|---|
| | | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - Sensitivity fuelprice -50% CASE 3.2** | Date | : July 2004 |

30 jul 2004 11:04

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 2306.4 | MW |
| Net power output | 784.8 | 774.6 | MW |
| CO2 output | 293.0 | 108.5 | t/h |
| Solid waste output | 0.00 | 1.84 | t/h |
| CO2 emissions | 373 | 140 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.031 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 1020.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 102.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 71.4 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1194.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 5.3 |
| **Total working capital** | **0.2** | **5.8** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 66.4 | 54.6 |
| Maintenance | 7.9 | 36.2 |
| Chemicals + consumables | 1.7 | 5.2 |
| Insurance and local taxes | 7.1 | 27.5 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 4.7 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 1.50 | 0.75 | $/GJ |
| CO2 price | 174.7 | 174.7 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 40 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 174.723 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 28.02% | |
| Capital | 54.48% | |
| Other costs | 17.50% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 94.2 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 125.7 | 115.2 | 62.0 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 124.4 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -44.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -59.8 | -54.8 | -24.5 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -16.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -4.7 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -2.3 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.3 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -27.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -238.8 | -537.4 | -418.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -5.8 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -189.8 | -488.4 | -373.7 | 104.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -276.3 | -764.7 | -1138.5 | -1034.5 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | 117.1 | |
| CO2 revenues(based on power output retrofit case) | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | 235.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | -46.4 | |
| Maintenance | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | |
| Labour | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | |
| Chemicals & consumables | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | |
| Waste disposal | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | |
| Insurance and local taxes | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5.9 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 235.9 | 5.9 |
| Total Cash Flow (cumulated) | -798.6 | -562.7 | -326.8 | -90.9 | 144.9 | 380.8 | 616.7 | 852.6 | 1088.5 | 1324.4 | 1560.3 | 1796.2 | 2032.1 | 2267.9 | 2273.9 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Reference CASE discount rate 5%**

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| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.703 | | c/kWh |
| | | | |
| Retrofit year (n) | | 100 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 132.9 | 132.9 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 5.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 203.6 | 203.6 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

**Results summary**

| | | |
|---|---|---|
| Emission avoidance cost | 203.562 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 5.00% | |

**Breakdown of c/kWh cost**

| | |
|---|---|
| Fuel | 71.52% |
| Capital | 18.27% |
| Other costs | 10.20% |

### CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 125.4 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 20.8 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -394.2 | -363.5 | -332.8 | -302.1 | -271.4 | -240.7 | -210.0 | -179.3 | -148.6 | -117.9 | -87.2 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | |
| Maintenance | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| Labour | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | |
| Chemicals & consumables | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 0.2 |
| Total Cash Flow (cumulated) | -56.5 | -25.8 | 4.9 | 35.6 | 66.3 | 97.0 | 127.7 | 158.4 | 189.1 | 219.8 | 250.5 | 281.2 | 311.9 | 342.6 | 342.8 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Discount rate 5% CASE 1**

30 jul 2004 11:04

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.703 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| **Operating Costs at 100% load factor** | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 132.9 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 5.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 59.4 | 59.4 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 59.429 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 5.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 62.05% | |
| Capital | 25.48% | |
| Other costs | 12.46% | |

### CASH FLOW ANALYSIS

| **Million $** | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | | | | 125.4 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 153.3 | 100.0 | 133.4 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 67.4 | 89.8 |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -89.7 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -10.4 | -13.8 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.8 | -1.8 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -1.6 | -2.2 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | -0.1 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -13.8 | -13.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -158.0 | -237.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 20.8 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | -127.3 | -209.6 | 49.8 | 71.9 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -394.2 | -363.5 | -332.8 | -302.1 | -271.4 | -240.7 | -210.0 | -179.3 | -306.6 | -516.2 | -466.4 | -394.6 |

| **Million $** | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | 133.4 | |
| CO2 revenues(based on power output retrofit case) | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | 89.8 | |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | |
| Maintenance | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| Labour | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | |
| Chemicals & consumables | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | -2.2 | |
| Waste disposal | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | |
| Insurance and local taxes | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 0.4 |
| Total Cash Flow (cumulated) | -322.7 | -250.9 | -179.0 | -107.2 | -35.3 | 36.5 | 108.4 | 180.2 | 252.1 | 323.9 | 395.8 | 467.6 | 539.5 | 539.9 |

| | | |
|---|---|---|
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - Discount rate 5% CASE 2.1** | Version 4.5 |
| 30 jul 2004 11:04 | | Date : July 2004 |

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1672.4 | MW |
| Net power output | 784.8 | 693.7 | MW |
| CO2 output | 293.0 | 50.1 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 72 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.703 | | c/kWh |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 486.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 48.6 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 34.0 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **569.1** |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 158.2 |
| Maintenance | 7.9 | 18.7 |
| Chemicals + consumables | 1.7 | 11.2 |
| Insurance and local taxes | 7.1 | 16.8 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 2.3 |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 5.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 79.0 | 79.0 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 20 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| Results summary | | |
|---|---|---|
| Emission avoidance cost | 79.020 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 5.00% | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 59.72% | |
| Capital | 26.24% | |
| Other costs | 14.04% | |

**CASH FLOW ANALYSIS**

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 125.4 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 153.3 | 110.9 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 97.6 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -106.8 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -12.6 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -2.3 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -7.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -16.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -227.6 | -341.5 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 20.8 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | -196.9 | -314.0 | 61.3 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -394.2 | -363.5 | -332.8 | -302.1 | -271.4 | -240.7 | -210.0 | -179.3 | -376.2 | -690.2 | -628.9 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | 147.8 | |
| CO2 revenues(based on power output retrofit case) | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | 130.1 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | |
| Maintenance | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| Labour | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Chemicals & consumables | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 89.5 | 1.2 |
| Total Cash Flow (cumulated) | -539.5 | -450.0 | -360.5 | -271.0 | -181.6 | -92.1 | -2.6 | 86.9 | 176.4 | 265.8 | 355.3 | 444.8 | 534.3 | 623.7 | 624.9 |

Version 4.5
Date : July 2004

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Discount rate 5% CASE 2.2**

30 jul 2004 11:04

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1671.0 | MW |
| Net power output | 784.8 | 667.4 | MW |
| $CO_2$ output | 293.0 | 49.9 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| $CO_2$ emissions | 373 | 75 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| $CO_2$ emissions | 373 | | g/kWh |
| Electricity cost | 2.703 | | c/kWh |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 641.2 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 64.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 44.9 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **750.3** |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| **Operating Costs at 100% load factor** | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 158.1 |
| Maintenance | 7.9 | 22.1 |
| Chemicals + consumables | 1.7 | 10.8 |
| Insurance and local taxes | 7.1 | 19.9 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 3.5 |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 5.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| $CO_2$ price | 102.5 | 102.5 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 102.470 | $/t $CO_2$ |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the $CO_2$ emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 5.00% | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 56.70% | |
| Capital | 28.54% | |
| Other costs | 14.76% | |

### CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 125.4 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 153.3 | 106.7 |
| $CO_2$ revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 120.7 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -106.7 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.9 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -7.3 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -19.9 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -300.1 | -450.2 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 20.8 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | -269.4 | -422.7 | 74.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -394.2 | -363.5 | -332.8 | -302.1 | -271.4 | -240.7 | -210.0 | -179.3 | -448.7 | -871.4 | -797.4 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | 142.2 | |
| $CO_2$ revenues(based on power output retrofit case) | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | 161.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | |
| Maintenance | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 107.8 | 1.1 |
| Total Cash Flow (cumulated) | -689.6 | -581.8 | -474.0 | -366.2 | -258.4 | -150.6 | -42.8 | 65.0 | 172.8 | 280.6 | 388.4 | 496.2 | 604.0 | 711.8 | 712.9 |

Version 4.5
Date : July 2004

# IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Discount rate 5% CASE 3.1**

30 jul 2004 11:04

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 2121.2 | MW |
| Net power output | 784.8 | 751.2 | MW |
| CO2 output | 293.0 | 97.6 | t/h |
| Solid waste output | 0.00 | 1.70 | t/h |
| CO2 emissions | 373 | 130 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.703 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 822.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 82.2 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 57.6 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **962.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 9.7 |
| **Total working capital** | **0.2** | **10.2** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 132.9 | 100.3 |
| Maintenance | 7.9 | 31.8 |
| Chemicals + consumables | 1.7 | 4.7 |
| Insurance and local taxes | 7.1 | 23.5 |
| Waste disposal | 0.0 | 2.7 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 5.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 95.3 | 95.3 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

**Results summary**

| | | |
|---|---|---|
| Emission avoidance cost | 95.270 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 5.00% | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 47.67% | |
| Capital | 35.28% | |
| Other costs | 17.05% | |

## CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 125.4 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 153.3 | 80.0 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 68.7 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -45.2 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -2.1 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.2 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -23.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -192.4 | -433.0 | -336.8 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -10.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 20.8 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | -161.7 | -402.3 | -309.3 | 48.7 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -394.2 | -363.5 | -332.8 | -302.1 | -271.4 | -240.7 | -210.0 | -371.7 | -774.0 | -1083.3 | -1034.6 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | 151.2 | |
| CO2 revenues(based on power output retrofit case) | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | 129.7 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | |
| Maintenance | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | -4.0 | |
| Waste disposal | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Insurance and local taxes | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.3 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 135.2 | 10.3 |
| Total Cash Flow (cumulated) | -899.5 | -764.3 | -629.1 | -493.9 | -358.7 | -223.5 | -88.3 | 46.8 | 182.0 | 317.2 | 452.4 | 587.6 | 722.8 | 858.0 | 868.3 |

| | | | | |
|---|---|---|---|---|
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - Discount rate 5% CASE 3.2** | | Version | 4.5 |
| 30 jul 2004 11:04 | | | Date | : July 2004 |

| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2306.4 | MW |
| Net power output | 784.8 | 774.6 | MW |
| CO2 output | 293.0 | 108.5 | t/h |
| Solid waste output | 0.00 | 1.84 | t/h |
| CO2 emissions | 373 | 140 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.703 | | c/kWh |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | REFEREN **Million $** | RETROFIT **Million $** |
|---|---|---|
| Installed costs | 354.7 | 1020.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 102.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 71.4 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1194.2** |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 10.5 |
| **Total working capital** | **0.2** | **11.1** |

| **Operating Costs at 100% load factor** | REFEREN **MM $/year** | RETROFIT **MM $/year** |
|---|---|---|
| Fuel | 132.9 | 109.1 |
| Maintenance | 7.9 | 36.2 |
| Chemicals + consumables | 1.7 | 5.3 |
| Insurance and local taxes | 7.1 | 27.5 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 4.7 |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 5.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 123.9 | 123.9 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 40 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 123.881 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 5.00% | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 45.32% | |
| Capital | 37.13% | |
| Other costs | 17.55% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 125.4 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 167.2 | 153.3 | 82.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 88.2 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -49.1 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -16.3 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -4.7 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.2 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.6 | -1.4 | -2.4 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.3 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -27.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -238.8 | -537.4 | -418.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -11.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 20.8 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | 30.7 | -208.1 | -506.7 | -390.5 | 58.4 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -394.2 | -363.5 | -332.8 | -302.1 | -271.4 | -240.7 | -210.0 | -418.1 | -924.8 | -1315.3 | -1256.9 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | 155.9 | |
| CO2 revenues(based on power output retrofit case) | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | 166.6 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | |
| Maintenance | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | |
| Labour | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | |
| Chemicals & consumables | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | -4.5 | |
| Waste disposal | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | |
| Insurance and local taxes | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 159.8 | 11.2 |
| Total Cash Flow (cumulated) | -1097.1 | -937.3 | -777.4 | -617.6 | -457.8 | -298.0 | -138.1 | 21.7 | 181.5 | 341.4 | 501.2 | 661.0 | 820.8 | 980.7 | 991.9 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | | **Cost Evaluation - Retrofit year - 5 year CASE 1** | | Date | : July 2004 |
| 30 jul 2004 11:04 | | | | | |

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 5 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 5 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 132.9 | 132.9 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 69.0 | 69.0 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 69.016 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 53.12% | |
| Capital | 35.25% | |
| Other costs | 11.63% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 83% | 68% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7227 | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | 0% | 40% | 60% | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 170.0 | 110.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 78.2 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -109.6 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -6.5 | -10.4 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.4 | -1.6 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | -158.0 | -237.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | -109.0 | -192.8 | 71.6 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -391.5 | -584.3 | -512.7 | -411.8 | -310.8 | -209.9 | -108.9 | -8.0 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | |
| CO2 revenues(based on power output retrofit case) | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | 104.3 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | |
| Maintenance | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| Labour | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | |
| Chemicals & consumables | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | |
| Waste disposal | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | |
| Insurance and local taxes | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 100.9 | 0.4 |
| Total Cash Flow (cumulated) | 93.0 | 193.9 | 294.9 | 395.8 | 496.7 | 597.7 | 698.6 | 799.6 | 900.5 | 1001.5 | 1102.4 | 1203.4 | 1304.3 | 1405.3 | 1405.6 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Retrofit year - 5 year CASE 2.1**

Version 4.5
Date : July 2004

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| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1672.4 | MW |
| Net power output | 784.8 | 693.7 | MW |
| CO2 output | 293.0 | 50.1 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 72 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 5 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 486.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 48.6 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 34.0 |
| Retrofit escalation basis year | | 5 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **569.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 158.2 |
| Maintenance | 7.9 | 18.7 |
| Chemicals + consumables | 1.7 | 11.1 |
| Insurance and local taxes | 7.1 | 16.8 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 2.3 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 89.5 | 89.5 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 20 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

**Results summary**

| | | |
|---|---|---|
| Emission avoidance cost | 89.531 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |

**Breakdown of c/kWh cost**

| | |
|---|---|
| Fuel | 51.16% |
| Capital | 35.49% |
| Other costs | 13.35% |

### CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 83% | 68% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7227 | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | 0% | 40% | 60% | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 170.0 | 122.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 110.6 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -109.6 | -106.8 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -6.5 | -12.6 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.4 | -7.5 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | -227.6 | -341.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | -178.6 | -297.2 | 86.4 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -461.1 | -758.3 | -671.9 | -549.0 | -426.0 | -303.0 | -180.1 | -57.1 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | |
| CO2 revenues(based on power output retrofit case) | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | 147.4 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | |
| Maintenance | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| Labour | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Chemicals & consumables | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 1.2 |
| Total Cash Flow (cumulated) | 65.8 | 188.8 | 311.8 | 434.7 | 557.7 | 680.6 | 803.6 | 926.6 | 1049.5 | 1172.5 | 1295.5 | 1418.4 | 1541.4 | 1664.3 | 1665.5 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Retrofit year - 5 year CASE 2.2**

30 jul 2004 11:04

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1671.0 | MW |
| Net power output | 784.8 | 667.4 | MW |
| CO2 output | 293.0 | 49.9 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 75 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 5 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 641.2 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 64.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 44.9 |
| Retrofit escalation basis year | | 5 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **750.3** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 158.1 |
| Maintenance | 7.9 | 22.1 |
| Chemicals + consumables | 1.7 | 10.7 |
| Insurance and local taxes | 7.1 | 19.9 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 116.8 | 116.8 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| Results summary | | |
|---|---|---|
| Emission avoidance cost | 116.761 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 47.88% | |
| Capital | 38.09% | |
| Other costs | 14.03% | |

**CASH FLOW ANALYSIS**

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 83% | 68% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7227 | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | 0% | 40% | 60% | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 170.0 | 118.3 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 137.6 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -109.6 | -106.7 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -6.5 | -14.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.4 | -7.2 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | -300.1 | -450.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | -251.1 | -405.9 | 102.5 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -533.6 | -939.5 | -837.0 | -691.2 | -545.4 | -399.5 | -253.7 | -107.9 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | |
| CO2 revenues(based on power output retrofit case) | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | 183.4 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | |
| Maintenance | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 145.8 | 1.1 |
| Total Cash Flow (cumulated) | 37.9 | 183.7 | 329.5 | 475.3 | 621.1 | 767.0 | 912.8 | 1058.6 | 1204.4 | 1350.2 | 1496.0 | 1641.8 | 1787.6 | 1933.5 | 1934.6 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Retrofit year - 5 year CASE 3.1**

30 jul 2004 11:04

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2121.2 | MW |
| Net power output | 784.8 | 751.2 | MW |
| CO2 output | 293.0 | 97.6 | t/h |
| Solid waste output | 0.00 | 1.70 | t/h |
| CO2 emissions | 373 | 130 | g/kWh |

| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
|---|---|---|---|
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |

| | | | |
|---|---|---|---|
| Retrofit year (n) | | 5 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | **REFEREN** **Million $** | **RETROFIT** **Million $** |
|---|---|---|
| Installed costs | 354.7 | 822.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 82.2 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 57.6 |
| Retrofit escalation basis year | | 4 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **962.2** |

| **Working Capital** | | |
|---|---|---|
| Chemicals storage | 0.2 | 0.4 |
| Fuel storage | 0.0 | 9.7 |
| **Total working capital** | **0.2** | **10.1** |

| **Operating Costs** **at 100% load factor** | **REFEREN** **MM $/year** | **RETROFIT** **MM $/year** |
|---|---|---|
| Fuel | 132.9 | 100.3 |
| Maintenance | 7.9 | 31.8 |
| Chemicals + consumables | 1.7 | 4.6 |
| Insurance and local taxes | 7.1 | 23.5 |
| Waste disposal | 0.0 | 2.7 |
| Operating labour | 1.2 | 3.5 |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 118.9 | 118.9 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 118.922 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |

| **Breakdown of c/kWh cost** | |
|---|---|
| Fuel | 36.78% |
| Capital | 47.10% |
| Other costs | 16.12% |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 83% | 45% | 85% | 85% | 85% | 85% | 85% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7227 | 3942 | 7446 | 7446 | 7446 | 7446 | 7446 |
| **Expenditure Factor** | 0% | 40% | 60% | | | 20% | 45% | 35% | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 170.0 | 88.8 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 85.7 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -109.6 | -45.2 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -6.5 | -14.3 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.4 | -2.1 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.2 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | -192.4 | -433.0 | -336.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | -10.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | -143.4 | -384.0 | -292.5 | 74.5 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -474.9 | -858.9 | -1151.4 | -1076.9 | -893.0 | -709.1 | -525.2 | -341.2 | -157.3 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | |
| CO2 revenues(based on power output retrofit case) | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | 161.9 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | |
| Maintenance | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | |
| Waste disposal | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Insurance and local taxes | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.3 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 183.9 | 10.3 |
| Total Cash Flow (cumulated) | 26.6 | 210.6 | 394.5 | 578.4 | 762.4 | 946.3 | 1130.2 | 1314.2 | 1498.1 | 1682.0 | 1866.0 | 2049.9 | 2233.8 | 2417.7 | 2428.0 |

Version 4.5
Date : July 2004

**IEA GREENHOUSE GAS R&D PROGRAMME**

**Cost Evaluation - Retrofit year - 5 year CASE 3.2**

30 jul 2004 11:04

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2306.4 | MW |
| Net power output | 784.8 | 774.6 | MW |
| CO2 output | 293.0 | 108.5 | t/h |
| Solid waste output | 0.00 | 1.84 | t/h |
| CO2 emissions | 373 | 140 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 5 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 1020.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 102.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 71.4 |
| Retrofit escalation basis year | | 4 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1194.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 10.5 |
| **Total working capital** | **0.2** | **11.1** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 132.9 | 109.1 |
| Maintenance | 7.9 | 36.2 |
| Chemicals + consumables | 1.7 | 5.2 |
| Insurance and local taxes | 7.1 | 27.5 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 4.7 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 152.6 | 152.6 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 40 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 152.577 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 34.74% | |
| Capital | 48.76% | |
| Other costs | 16.51% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 83% | 45% | 85% | 85% | 85% | 85% | 85% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7227 | 3942 | 7446 | 7446 | 7446 | 7446 | 7446 |
| **Expenditure Factor** | 0% | 40% | 60% | | | 20% | 45% | 35% | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 170.0 | 91.5 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 108.6 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -109.6 | -49.1 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -6.5 | -16.3 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.4 | -2.3 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.3 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | -238.8 | -537.4 | -418.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | -11.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | -189.8 | -488.4 | -373.7 | 87.9 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -521.3 | -1009.7 | -1383.4 | -1295.6 | -1080.1 | -864.6 | -649.1 | -433.6 | -218.2 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | |
| CO2 revenues(based on power output retrofit case) | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | 205.2 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | |
| Maintenance | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | |
| Labour | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | |
| Chemicals & consumables | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | |
| Waste disposal | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | |
| Insurance and local taxes | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 215.5 | 11.2 |
| Total Cash Flow (cumulated) | -2.7 | 212.8 | 428.3 | 643.7 | 859.2 | 1074.7 | 1290.2 | 1505.6 | 1721.1 | 1936.6 | 2152.1 | 2367.5 | 2583.0 | 2798.5 | 2809.7 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Retrofit year + 5 year CASE 1**

30 jul 2004 11:04

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1404.6 | MW |
| Net power output | 784.8 | 625.9 | MW |
| CO2 output | 293.0 | 41.9 | t/h |
| Solid waste output | 0.00 | 0.04 | t/h |
| CO2 emissions | 373 | 67 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 15 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 337.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 33.8 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 23.6 |
| Retrofit escalation basis year | | 15 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **395.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 132.9 | 132.9 |
| Maintenance | 7.9 | 15.4 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 13.8 |
| Waste disposal | 0.0 | 0.1 |
| Operating labour | 1.2 | 1.8 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 82.8 | 82.8 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 82.770 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 59.92% | |
| Capital | 30.27% | |
| Other costs | 9.81% | |

### CASH FLOW ANALYSIS

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 | 158.5 |

| **Million $** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 83% | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7227 | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | 185.5 | 185.5 | 170.0 | 110.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | 147.9 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 93.8 | 125.1 | 125.1 | 125.1 | 125.1 | 125.1 | 125.1 | 125.1 | 125.1 | 125.1 | |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -109.6 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | |
| Maintenance | -7.1 | -7.1 | -6.5 | -10.4 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| Labour | -1.2 | -1.2 | -1.2 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | |
| Chemicals & consumables | -1.5 | -1.5 | -1.4 | -1.6 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | -13.8 | |
| **Fixed Capital Expenditures** | 0.0 | -158.0 | -237.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 49.0 | -109.0 | -192.8 | 87.2 | 121.7 | 121.7 | 121.7 | 121.7 | 121.7 | 121.7 | 121.7 | 121.7 | 121.7 | 0.4 |
| Total Cash Flow (cumulated) | 207.5 | 98.5 | -94.3 | -7.2 | 114.6 | 236.3 | 358.0 | 479.8 | 601.5 | 723.3 | 845.0 | 966.7 | 1088.5 | 1088.8 |

Version 4.5
Date : July 2004

# IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Retrofit year + 5 year CASE 2.1**

30 jul 2004 11:04

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1672.4 | MW |
| Net power output | 784.8 | 693.7 | MW |
| CO2 output | 293.0 | 50.1 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 72 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 15 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 486.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 48.6 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 34.0 |
| Retrofit escalation basis year | | 15 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **569.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 158.2 |
| Maintenance | 7.9 | 18.7 |
| Chemicals + consumables | 1.7 | 11.1 |
| Insurance and local taxes | 7.1 | 16.8 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 2.3 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 107.5 | 107.5 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 20 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| Results summary | | |
|---|---|---|
| Emission avoidance cost | 107.494 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 58.55% | |
| Capital | 31.04% | |
| Other costs | 10.41% | |

**CASH FLOW ANALYSIS**

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 | 158.5 |

| Million $ | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 83% | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7227 | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | 185.5 | 185.5 | 170.0 | 122.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | 163.9 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 132.7 | 177.0 | 177.0 | 177.0 | 177.0 | 177.0 | 177.0 | 177.0 | 177.0 | 177.0 | |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -109.6 | -106.8 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | -142.4 | |
| Maintenance | -7.1 | -7.1 | -6.5 | -12.6 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| Labour | -1.2 | -1.2 | -1.2 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Chemicals & consumables | -1.5 | -1.5 | -1.4 | -7.5 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | -16.8 | |
| **Fixed Capital Expenditures** | 0.0 | -227.6 | -341.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -1.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 49.0 | -178.6 | -297.2 | 108.6 | 152.5 | 152.5 | 152.5 | 152.5 | 152.5 | 152.5 | 152.5 | 152.5 | 152.5 | 1.2 |
| Total Cash Flow (cumulated) | 207.5 | 28.8 | -268.4 | -159.8 | -7.3 | 145.3 | 297.8 | 450.4 | 602.9 | 755.4 | 908.0 | 1060.5 | 1213.0 | 1214.2 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

**IEA GREENHOUSE GAS R&D PROGRAMME**

**Cost Evaluation - Retrofit year + 5 year CASE 2.2**

30 jul 2004 11:04

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1671.0 | MW |
| Net power output | 784.8 | 667.4 | MW |
| CO2 output | 293.0 | 49.9 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 75 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 15 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 641.2 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 64.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 44.9 |
| Retrofit escalation basis year | | 15 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **750.3** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 132.9 | 158.1 |
| Maintenance | 7.9 | 22.1 |
| Chemicals + consumables | 1.7 | 10.7 |
| Insurance and local taxes | 7.1 | 19.9 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 141.4 | 141.4 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 141.415 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 56.85% | |
| Capital | 32.51% | |
| Other costs | 10.64% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 83% | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7227 | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 185.5 | 185.5 | 185.5 | 170.0 | 118.3 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | 157.7 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 0.0 | 166.6 | 222.1 | 222.1 | 222.1 | 222.1 | 222.1 | 222.1 | 222.1 | 222.1 | 222.1 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -119.6 | -109.6 | -106.7 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | -142.3 | |
| Maintenance | -7.1 | -7.1 | -7.1 | -6.5 | -14.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| Labour | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -1.5 | -1.5 | -1.5 | -1.4 | -7.2 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -7.1 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | -19.9 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | -300.1 | -450.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 49.0 | 49.0 | -251.1 | -405.9 | 131.6 | 184.5 | 184.5 | 184.5 | 184.5 | 184.5 | 184.5 | 184.5 | 184.5 | 184.5 | 1.1 |
| Total Cash Flow (cumulated) | 158.5 | 207.5 | -43.6 | -449.5 | -318.0 | -133.4 | 51.1 | 235.6 | 420.2 | 604.7 | 789.2 | 973.8 | 1158.3 | 1342.9 | 1344.0 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - Retrofit year + 5 year CASE 3.1**

30 jul 2004 11:04

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2121.2 | MW |
| Net power output | 784.8 | 751.2 | MW |
| $CO_2$ output | 293.0 | 97.6 | t/h |
| Solid waste output | 0.00 | 1.70 | t/h |
| $CO_2$ emissions | 373 | 130 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| $CO_2$ emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 15 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 822.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 82.2 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 57.6 |
| Retrofit escalation basis year | | 14 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **962.2** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.4 |
| Fuel storage | 0.0 | 9.7 |
| **Total working capital** | **0.2** | **10.1** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 100.3 |
| Maintenance | 7.9 | 31.8 |
| Chemicals + consumables | 1.7 | 4.6 |
| Insurance and local taxes | 7.1 | 23.5 |
| Waste disposal | 0.0 | 2.7 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| $CO_2$ price | 159.7 | 159.7 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| Results summary | | |
|---|---|---|
| Emission avoidance cost | 159.710 | $/t $CO_2$ |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the $CO_2$ emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 52.69% | |
| Capital | 36.13% | |
| Other costs | 11.18% | |

### CASH FLOW ANALYSIS

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 |
| $CO_2$ revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 | 158.5 |

| Million $ | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 83% | 45% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7227 | 3942 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | 20% | 45% | 35% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | 185.5 | 185.5 | 170.0 | 88.8 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | 167.7 | |
| $CO_2$ revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 115.1 | 217.4 | 217.4 | 217.4 | 217.4 | 217.4 | 217.4 | 217.4 | 217.4 | 217.4 | |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -109.6 | -45.2 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | -85.3 | |
| Maintenance | -7.1 | -7.1 | -6.5 | -14.3 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | -27.1 | |
| Labour | -1.2 | -1.2 | -1.2 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -1.5 | -1.5 | -1.4 | -2.1 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | -1.2 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | -23.5 | |
| **Fixed Capital Expenditures** | -192.4 | -433.0 | -336.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -10.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.3 |
| **Decommissioning Cost** | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | -143.4 | -384.0 | -292.5 | 103.9 | 239.5 | 239.5 | 239.5 | 239.5 | 239.5 | 239.5 | 239.5 | 239.5 | 239.5 | 10.3 |
| Total Cash Flow (cumulated) | 15.0 | -368.9 | -661.5 | -557.6 | -318.1 | -78.7 | 160.8 | 400.3 | 639.7 | 879.2 | 1118.7 | 1358.1 | 1597.6 | 1607.9 |

| | | | |
|---|---|---|---|
| | | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - Retrofit year + 5 year CASE 3.2** | Date | : July 2004 |
| 30 jul 2004 11:04 | | | |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 2306.4 | MW |
| Net power output | 784.8 | 774.6 | MW |
| CO2 output | 293.0 | 108.5 | t/h |
| Solid waste output | 0.00 | 1.84 | t/h |
| CO2 emissions | 373 | 140 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| Retrofit year (n) | | 15 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 1020.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 102.1 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 71.4 |
| Retrofit escalation basis year | | 14 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1194.2** |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 10.5 |
| **Total working capital** | **0.2** | **11.1** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 132.9 | 109.1 |
| Maintenance | 7.9 | 36.2 |
| Chemicals + consumables | 1.7 | 5.2 |
| Insurance and local taxes | 7.1 | 27.5 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 4.7 |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 203.6 | 203.6 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 40 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 203.562 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 50.96% | |
| Capital | 37.65% | |
| Other costs | 11.39% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | 11.5 | 60.5 | 109.5 | 158.5 |

| **Million $** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 83% | 45% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7227 | 3942 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | 20% | 45% | 35% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | 185.5 | 185.5 | 170.0 | 91.5 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | 172.9 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 144.9 | 273.8 | 273.8 | 273.8 | 273.8 | 273.8 | 273.8 | 273.8 | 273.8 | 273.8 | |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | -119.6 | -119.6 | -109.6 | -49.1 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | -92.7 | |
| Maintenance | -7.1 | -7.1 | -6.5 | -16.3 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | -30.7 | |
| Labour | -1.2 | -1.2 | -1.2 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | |
| Chemicals & consumables | -1.5 | -1.5 | -1.4 | -2.3 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | -1.3 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | |
| Insurance and local taxes | -7.1 | -7.1 | -7.1 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | -27.5 | |
| **Fixed Capital Expenditures** | -238.8 | -537.4 | -418.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -11.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | -189.8 | -488.4 | -373.7 | 124.2 | 284.0 | 284.0 | 284.0 | 284.0 | 284.0 | 284.0 | 284.0 | 284.0 | 284.0 | 11.2 |
| Total Cash Flow (cumulated) | -31.4 | -519.7 | -893.5 | -769.3 | -485.2 | -201.2 | 82.9 | 366.9 | 651.0 | 935.0 | 1219.1 | 1503.1 | 1787.1 | 1798.4 |

# Appendix 8

Task 1 – Same Output Retrofit

## Task 1 – Same Output Retrofit

### Introduction

The common basis for the study is the capture of 85% of carbon in the feedstock. This results in a reduced and widely variable net output of electricity across the cases, as compared to the reference plant, from less than 2% to more than 25%.

Some operators might be interested in an option to capture 85% of the carbon and at the same time retain the original plant output. This may be required to maintain installed nameplate capacity at specific parts of the network for regulatory compliance, or it could be to comply with an existing off-take agreement.

In order to achieve this it is necessary in most cases to install supplementary combined cycle power plants. These would operate, in the same mode as the refuelled CCPP with 85% of the carbon in the fuel captured as $CO_2$. The closest fit gas turbine is chosen for each case to generate a total plant output as close as possible to the reference plant.

### Process Description and Performances

A breakdown of the additional power generation required to bring each of the capture cases back to the reference case output is given in table 1 below. A summary of the revised plant performances and costs are given in tables 2, 3 and 4 below with further details at the end of this appendix.

Table 1 Additional Power Requirements

| **Additional Power Requirements** | Ref. | 1 | 2-1 | 2-2 | 3-1 | 3-2 | |
|---|---|---|---|---|---|---|---|
| Combined Cycle Power Plant Net Electrical Output | 784.8 | 664.3 | 809.6 | 764.3 | 806.0 | 774.3 | MWe |
| $CO_2$ Capture Plant Auxiliary Power Consumption | 0.0 | -38.5 | -158.9 | -168.0 | -244.9 | -269.1 | MWe |
| $CO_2$ Capture Plant Power Production | 0.0 | 0.0 | 43.0 | 71.1 | 190.1 | 269.4 | MWe |
| Total Overall Plant Net Power Output | 784.8 | 625.9 | 693.7 | 667.4 | 751.2 | 774.6 | MWe |
| Additional Power Required | 0 | 158.9 | 91.1 | 117.4 | 33.6 | 10.2 | MWe |

<u>Case 1</u>

For Case 1 an additional 159 MWe is required to bring the total output up to that of the Reference Case. The best fit for this additional output is to add a GE 9EA in combined cycle. This operates on natural gas in parallel to the original CCPP. The flue gases are routed to additional Acid Gas Removal trains and the CO2 is combined with that from the original CCPP and sent to an increased capacity CO2 Compression and Drying section. The throughput increase required in the Acid Gas Removal and $CO_2$ Compression and Drying units is 27%.

<u>Case 2-1</u>

In Case 2-1 an additional 91 MWe is required to bring the output to that of the reference plant. $CO_2$ free fuel gas feeds a supplementary GE 6FA, operating in combined cycle to generate this extra power. The GE 6 FA is well proven operating in syngas. The entire fuel generation part of the flowsheet (encompassing everything apart from the CCPP) is increased to generate the extra 16% fuel gas.

Case 2-2

Case 2-2 requires extra output of 117 MWe. The best fit turbine is a GE 9EA operating again in combined cycle. The GE 9 EA is well proven operating in syngas. Similar areas of the flowsheet to Case 2-1 increase in throughput to generate the $CO_2$ free fuel gas required. The required increased output of $CO_2$ free fuel gas is 27%.

Case 3-1

Case 3-1 has a shortfall of 34 MWe against the reference case. In this case the extra power is generated by an additional GE 6B gas turbine in combined cycle. This is added to the existing GE 6B gas turbines used in the Power Block for this case. The additional gas turbine also superheats the additional steam, generated by the increased fuel flow in the enlarged capture plant.
The fuel throughput increase required in this case is 10% over the original flowscheme. The entire flowscheme is increased to create this higher fuel requirement, with the exception of the original Power Block, which has an additional gas turbine added, and the CCPP, which remains the same as it, does in all the cases.

Case 3-2

The additional power required for Case 3-2 is only 10 MW. This is generated by 'stretching' the original flowscheme by increased supplementary firing in the HRSG of the Power Block. This extra duct burning actually reduces the surface required in the Power Block HRSG by improving the temperature driving force in the coils.
The fuel generation part of the plant is increased in throughput by 1%.

Table 2 – Plant Power Output (Reference Case Output)

| **Plant Power Output** | Ref. | 1 | 2-1 | 2-2 | 3-1 | 3-2 | |
|---|---|---|---|---|---|---|---|
| Combined Cycle Power Plant Net Electrical Output | 784.8 | 664.3 | 809.6 | 764.3 | 806.0 | 774.3 | MWe |
| Revised Capture Plant Auxiliary Power Consumption | 0.0 | -48.8 | -177.5 | -194.2 | -268.4 | -272.0 | MWe |
| Revised Capture Plant Power Production | 0.0 | 164.7 | 154.8 | 235.3 | 256.3 | 281.7 | MWe |
| Revised Overall Plant Net Power Output | 784.8 | 780.2 | 786.9 | 805.4 | 793.9 | 784.0 | MWe |
| Difference from Reference Plant | 0 | -0.6 | 0.3 | 2.6 | 1.2 | -0.1 | % |

Table 3 - Plant Performance (Reference Case Output)

| **Plant Performance** | Ref. | 1 | 2-1 | 2-2 | 3-1 | 3-2 | |
|---|---|---|---|---|---|---|---|
| Revised Overall Plant Fuel Consumption (LHV) | 1404.6 | 1780.1 | 1940.7 | 2123.1 | 2324.6 | 2331.6 | MWth |
| Fuel Gas to Combined Cycle Power Plant | 1404.6 | 1404.6 | 1672.4 | 1671.0 | 2121.2 | 2306.4 | MWth |
| Revised Overall Plant $CO_2$ emissions | 2.31 | 0.42 | 0.46 | 0.5 | 0.8 | 0.82 | Mt/y |
| Revised Overall Plant Net Electrical Efficiency | 55.9 | 43.8 | 40.6 | 37.9 | 34.2 | 33.6 | % |

## Economic Analysis

Table 4 – Additional Capital Expenditures (Reference Case Output)

| **Additional Capital Expenditures** | Ref. | 1 | 2-1 | 2-2 | 3-1 | 3-2 | |
|---|---|---|---|---|---|---|---|
| Additional Capital Costs[1] | - | 584 | 712 | 978 | 1045 | 1210 | Million US $ |
| Specific Total Investment | 529 | 1280 | 1432 | 1729 | 1839 | 2073 | US $/MWe |
| $CO_2$ Emission | 0.373 | 0.068 | 0.074 | 0.078 | 0.135 | 0.140 | t/MWh |
| Avoided $CO_2$ Emission (% of ref.) | - | 81.8 | 80.2 | 78.9 | 63.9 | 62.5 | % |
| Costs of Avoided $CO_2$ | - | 74.3 | 98.2 | 128.9 | 136.9 | 167.5 | US $/ton |

Notes
1. On top of capital expenditure for reference plant of 415 million US $
2. Calculated with electricity at 30.0 US $/MWh

## Conclusions

The study demonstrates that the reference case output can be generated with $CO_2$ capture using additional gas turbines all of which are commercially proven on syngas.
In all cases the overall efficiency is reduced. This is because the additional gas turbines are all less efficient than the GE 9FA used in the CCPP. In case 3-2, the reduction in efficiency is very small, because the additional power generation is achieved by a small, 1%, increase in capture plant capacity. No additional gas turbines are added and the plant configuration is not changed.

The reduced efficiency means that in all cases the $CO_2$ emitted per MWh increases and the increased throughput means that the avoided $CO_2$ when compared with the reference plant is also reduced.

The specific investment costs differ marginally (within 1%) for all cases compared to the original calculations.

| | | |
|---|---|---|
| Version | 4.5 | |
| Date | : July 2004 | |

# IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 1**

29 jul 2004 12:40

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 1780.1 | MW |
| Net power output | 784.8 | 780.2 | MW |
| CO2 output | 293.0 | 53.2 | t/h |
| Solid waste output | 0.00 | 0.06 | t/h |
| CO2 emissions | 373 | 68 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| Capital Cost | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 499.2 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 49.9 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 34.9 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **584.0** |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.2 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **0.2** |

| Operating Costs at 100% load factor | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 168.4 |
| Maintenance | 7.9 | 19.0 |
| Chemicals + consumables | 1.7 | 2.4 |
| Insurance and local taxes | 7.1 | 17.1 |
| Waste disposal | 0.0 | 0.2 |
| Operating labour | 1.2 | 1.8 |
| **Decommissioning cost** | 0 | 0 |

| Economic parameters | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 74.3 | 74.3 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 15 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

**Results summary**

| | | |
|---|---|---|
| Emission avoidance cost | 74.307 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |

**Breakdown of c/kWh cost**

| | |
|---|---|
| Fuel | 56.40% |
| Capital | 33.09% |
| Other costs | 10.51% |

**CASH FLOW ANALYSIS**

**Million $**

| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 000 | 00 | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 138.3 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 104.6 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -113.7 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -12.8 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.8 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -1.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.1 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -17.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -233.6 | -350.4 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -0.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -184.6 | -306.2 | 95.6 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -222.1 | -528.3 | -432.7 |

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | 184.4 | |
| CO2 revenues(based on power output retrofit case) | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | 139.5 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | -151.6 | |
| Maintenance | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | |
| Labour | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | -1.8 | |
| Chemicals & consumables | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | -2.1 | |
| Waste disposal | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | |
| Insurance and local taxes | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | -17.1 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 134.1 | 0.4 |
| Total Cash Flow (cumulated) | -298.6 | -164.5 | -30.5 | 103.6 | 237.7 | 371.7 | 505.8 | 639.9 | 773.9 | 908.0 | 1042.0 | 1176.1 | 1310.2 | 1444.2 | 1444.6 |

Version 4.5
Date : July 2004

# IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 2.1**

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| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 1404.6 | 1940.7 | MW |
| Net power output | 784.8 | 786.9 | MW |
| CO2 output | 293.0 | 58.1 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 74 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 608.6 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 60.9 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 42.6 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **712.1** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 132.9 | 183.6 |
| Maintenance | 7.9 | 21.4 |
| Chemicals + consumables | 1.7 | 11.1 |
| Insurance and local taxes | 7.1 | 19.3 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 2.3 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREN | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 98.2 | 98.2 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 20 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 98.189 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 54.87% | |
| Capital | 33.54% | |
| Other costs | 11.59% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 139.5 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 136.8 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -123.9 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -14.4 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -2.3 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -7.5 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -19.3 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -284.8 | -427.2 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -235.8 | -383.0 | 107.8 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -273.3 | -656.3 | -548.5 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | 186.0 | |
| CO2 revenues(based on power output retrofit case) | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | 182.4 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | -165.2 | |
| Maintenance | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | |
| Labour | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | |
| Chemicals & consumables | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | -10.0 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | -19.3 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 152.3 | 1.2 |
| Total Cash Flow (cumulated) | -396.3 | -244.0 | -91.7 | 60.5 | 212.8 | 365.1 | 517.4 | 669.6 | 821.9 | 974.2 | 1126.5 | 1278.7 | 1431.0 | 1583.3 | 1584.4 |

| | | | |
|---|---|---|---|
| | | Version | 4.5 |
| **IEA GREENHOUSE GAS R&D PROGRAMME** | **Cost Evaluation - CASE 2.2** | Date | : July 2004 |

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| **Production** | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2123.1 | MW |
| Net power output | 784.8 | 805.4 | MW |
| CO2 output | 293.0 | 63.4 | t/h |
| Solid waste output | 0.00 | 0.01 | t/h |
| CO2 emissions | 373 | 79 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 0% | - |
| Retrofit Expenditure year (n-1) | | 40% | - |
| Retrofit Expenditure year (n) | | 60% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 354.7 | 835.7 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 83.6 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 58.5 |
| Retrofit escalation basis year | | 10 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **977.8** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 1.0 |
| Fuel storage | 0.0 | 0.0 |
| **Total working capital** | **0.2** | **1.0** |

| | REFEREN | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 132.9 | 200.9 |
| Maintenance | 7.9 | 26.5 |
| Chemicals + consumables | 1.7 | 10.7 |
| Insurance and local taxes | 7.1 | 23.8 |
| Waste disposal | 0.0 | 0.0 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 90.0 | % |
| Fuel price | 3.00 | 3.00 | $/GJ |
| CO2 price | 128.9 | 128.9 | $/t |
| Waste disposal cost | 0.0 | 307.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 0 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 90 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 128.935 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 52.53% | |
| Capital | 35.54% | |
| Other costs | 11.93% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 68% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 5913 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 0% | 40% | 60% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 142.7 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 180.9 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -135.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -17.9 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -7.2 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -23.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -391.1 | -586.7 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -342.1 | -542.4 | 134.6 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -37.5 | -379.6 | -922.0 | -787.4 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | |
| **Equivalent yearly hours** | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | 190.3 | |
| CO2 revenues(based on power output retrofit case) | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | 241.2 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | -180.8 | |
| Maintenance | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | -9.7 | |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Insurance and local taxes | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | -23.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 189.9 | 1.1 |
| Total Cash Flow (cumulated) | -597.5 | -407.6 | -217.7 | -27.9 | 162.0 | 351.9 | 541.8 | 731.7 | 921.6 | 1111.5 | 1301.4 | 1491.3 | 1681.2 | 1871.1 | 1872.2 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 3.1**

29 jul 2004 12:40

| Production | REFEREN | RETROFIT | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2324.6 | MW |
| Net power output | 784.8 | 793.9 | MW |
| CO2 output | 293.0 | 106.7 | t/h |
| Solid waste output | 0.00 | 1.86 | t/h |
| CO2 emissions | 373 | 134 | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | REFEREN Million $ | RETROFIT Million $ |
|---|---|---|
| Installed costs | 354.7 | 893.4 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 89.3 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 62.5 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1045.3** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.4 |
| Fuel storage | 0.0 | 10.6 |
| **Total working capital** | **0.2** | **11.1** |

| **Operating Costs at 100% load factor** | REFEREN MM $/year | RETROFIT MM $/year |
|---|---|---|
| Fuel | 132.9 | 110.0 |
| Maintenance | 7.9 | 33.4 |
| Chemicals + consumables | 1.7 | 4.6 |
| Insurance and local taxes | 7.1 | 25.0 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 3.5 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | REFEREN | RETROFIT | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 136.9 | 136.9 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 136.861 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |

| **Breakdown of c/kWh cost** | |
|---|---|
| Fuel | 45.48% |
| Capital | 41.23% |
| Other costs | 13.29% |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% |
| **Revenues** | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -209.1 | -470.4 | -365.9 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -160.1 | -421.4 | -321.6 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -246.6 | -667.9 | -989.6 |

| **Million $** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 45% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 3942 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | | |
| Electricity | 93.8 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | 177.2 | |
| CO2 revenues(based on power output retrofit case) | 102.3 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | 193.2 | |
| **Operating Costs** | | | | | | | | | | | | | | | | |
| Fuel | -49.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | -93.5 | |
| Maintenance | -15.0 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | -28.4 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -2.1 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | -3.9 | |
| Waste disposal | -1.4 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | |
| Insurance and local taxes | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | -25.0 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | -11.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 88.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 213.6 | 11.2 |
| Total Cash Flow (cumulated) | -901.0 | -687.3 | -473.7 | -260.1 | -46.4 | 167.2 | 380.8 | 594.5 | 808.1 | 1021.7 | 1235.4 | 1449.0 | 1662.6 | 1876.3 | 2089.9 | 2101.1 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

## IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation - CASE 3.2**

29 jul 2004 12:40

| **Production** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Fuel feedrate | 1404.6 | 2331.6 | MW |
| Net power output | 784.8 | 784.0 | MW |
| CO2 output | 293.0 | 109.9 | t/h |
| Solid waste output | 0.00 | 1.86 | t/h |
| CO2 emissions | 373 | 140 | g/kWh |
| **Reference plant data** | *For calculation of cost of emission avoidanc* | | |
| CO2 emissions | 373 | | g/kWh |
| Electricity cost | 2.997 | | c/kWh |
| | | | |
| Retrofit year (n) | | 10 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| **Capital Cost** | **REFEREN Million $** | **RETROFIT Million $** |
|---|---|---|
| Installed costs | 354.7 | 1034.1 |
| Contingencies | 10.0% | 10.0% |
| | 35.5 | 103.4 |
| Owners costs | 7.0% | 7.0% |
| | 24.8 | 72.4 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **415.0** | **1209.8** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.2 | 0.5 |
| Fuel storage | 0.0 | 10.7 |
| **Total working capital** | **0.2** | **11.2** |

| **Operating Costs at 100% load factor** | **REFEREN MM $/year** | **RETROFIT MM $/year** |
|---|---|---|
| Fuel | 132.9 | 110.3 |
| Maintenance | 7.9 | 36.5 |
| Chemicals + consumables | 1.7 | 5.2 |
| Insurance and local taxes | 7.1 | 27.8 |
| Waste disposal | 0.0 | 3.0 |
| Operating labour | 1.2 | 4.7 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| **Economic parameters** | **REFEREN** | **RETROFIT** | |
|---|---|---|---|
| Discount rate | 10.0 | | % |
| Load factor | 90.0 | 85.0 | % |
| Fuel price | 3.00 | 1.50 | $/GJ |
| CO2 price | 167.5 | 167.5 | $/t |
| Waste disposal cost | 0.0 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 10 | 40 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 0 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year 1 | 90 | 60 | % |

| **Results summary** | | |
|---|---|---|
| Emission avoidance cost | 167.527 | $/t CO2 |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 43.65% | |
| Capital | 42.68% | |
| Other costs | 13.67% | |

### CASH FLOW ANALYSIS

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 68% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 90% | 83% | 45% |
| **Equivalent yearly hours** | | | | 5913 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7884 | 7227 | 3942 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | 20% | 45% | 35% | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 139.1 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 185.5 | 170.0 | 92.6 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 120.7 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -89.7 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -119.6 | -109.6 | -49.6 |
| Maintenance | 0.0 | 0.0 | 0.0 | -5.3 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -6.5 | -16.4 |
| Labour | 0.0 | 0.0 | 0.0 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -1.2 | -4.7 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.1 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.5 | -1.4 | -2.3 |
| Waste disposal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -1.4 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -7.1 | -27.8 |
| **Fixed Capital Expenditures** | 0.0 | -166.0 | -249.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -242.0 | -544.4 | -423.4 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -11.2 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -166.0 | -249.0 | 34.5 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | 49.0 | -193.0 | -495.4 | -379.2 | 100.0 |
| Total Cash Flow (cumulated) | 0.0 | -166.0 | -415.0 | -380.5 | -331.5 | -282.5 | -233.5 | -184.5 | -135.5 | -86.5 | -279.5 | -774.9 | -1154.1 | -1054.1 |

| **Million $** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | |
| CO2 revenues(based on power output retrofit case) | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | -93.8 | |
| Maintenance | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | -31.0 | |
| Labour | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | -4.7 | |
| Chemicals & consumables | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | -4.4 | |
| Waste disposal | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | -2.6 | |
| Insurance and local taxes | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | -27.8 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.3 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 238.8 | 11.3 |
| Total Cash Flow (cumulated) | -815.3 | -576.5 | -337.7 | -99.0 | 139.8 | 378.6 | 617.4 | 856.2 | 1095.0 | 1333.8 | 1572.6 | 1811.4 | 2050.2 | 2289.0 | 2300.3 |

# Appendix 9

Task 3 – Pre-Implementation Retrofit

**Task 3 - Pre-Implementation Retrofit**

**Introduction**

A major problem facing an intended new power plant investor is the choice between a plant design that cannot capture $CO_2$ and one that can only operate with $CO_2$ capture. With the former, he will face penalties under any carbon tax levy for which his only recourse is to pay. The latter choice will give him an uncompetitive plant for today that produces by-product $CO_2$ to no benefit.

The ideal option would be a plant designed to be capable of operating efficiently with or without $CO_2$ capture, dependant on the prevailing commercial conditions. However, it is generally perceived that a plant capable of capturing $CO_2$ cannot be operated efficiently when operating without $CO_2$ capture and existing IGCC plant design require major and costly changes to allow them to capture $CO_2$. Previous work by Jacobs demonstrates that a plant with pre-investment for future $CO_2$ capture could be commercially competitive if full advantage is taken of the non-captured $CO_2$ in increasing capture plant internal power output and reducing the parasitic power load by removing the requirement to inject nitrogen.

This option can be made available using the designs for Cases 3-1 and 3-2, renamed Cases 3-3 and 3-4 respectively. These designs could be operated to advantage without $CO_2$ capture. The fuel gas diluent of nitrogen and water vapour, both of which are energy intensive to use, could be replaced simply by leaving the $CO_2$ in the fuel gas. Here it acts as the diluent and is eventually discharged up the stacks of the CCPP and Power Block.

**Process Description and Performances**

<u>Case 3-3</u>

The flowscheme of the fuel production plant (rather than a capture plant) is very similar to the flowscheme for the capture plant. The three differences are that the Acid Gas Removal unit does not remove $CO_2$ from the fuel gas, the $CO_2$ Compression and Drying section is omitted as are the large nitrogen compressors from the Fuel Gas Conditioning section.

The equipment to remove $CO_2$ from the fuel gas can easily be added to the Acid Gas Removal unit as can the equipment for $CO_2$ Compression and Drying and the nitrogen compressors required for the Fuel Gas Conditioning section.

The gas leaving the Acid Gas Removal section is therefore sulphur free, but rich in $CO_2$. The Gas Conditioning section simply heats the gas using heat recovered from the Cooling section. There is no need for any nitrogen addition as this gas is in fact ideal for feeding to the CCPP, having a flame temperature coincident with 25ppm $NO_x$.

The hot syngas passes to the Power Block and the CCPP as in the $CO_2$ removal case.

One difference to the $CO_2$ removal case is that the Power Block in this case requires two GE 6B gas turbines to make best use of the stream generated from waste heat recovered in the Cooling section. The power generation in this case is therefore significantly larger than the $CO_2$ removal case reported, due to the existence of the additional gas turbine together with the additional fuel gas mass flow achieved using $CO_2$ as a diluent rather than nitrogen. Therefore the output from the gas turbines in both the Power Block and the CCPP are increased. There is also lower internal power consumption as there is no need to compress $CO_2$ or large quantities of nitrogen.

A summary of the plant performance and costs is given in tables 1 and 2 below and at the end of this appendix.

Case 3-4

This case is essentially the same as case 3-3 although with the remote turbine there is no preheating of the fuel to the CCPP. Instead this is achieved using steam from the HRSG of the CCPP. The steam is condensed and returned to the HRSG as there is no need for additional diluent for the gas turbine as there was in the $CO_2$ removal case.

The Gas Conditioning block in this case only preheats the Power Block fuel as these are local to the fuel gas generation plant.

The Power Block in this case has the same number of gas turbines as the $CO_2$ removal case, so there is no increased output due to this although all the other factors mentioned above for case 3-3 also apply to this case as well.
A summary of the plant performance and costs is given in tables 1 and 2 below and at the end of this appendix.

Table 1 – Plant Performance Output (No $CO_2$ Capture)

| **Plant Performance Output** | Ref. | 3-3 | 3-4 | |
|---|---|---|---|---|
| Combined Cycle Power Plant Net Electrical Output | 784.8 | 846.6 | 820.8 | MWe |
| Fuel Plant Auxiliary Power Consumption | - | -154.3 | -158.9 | MWe |
| Fuel Plant Power Production | - | 281.3 | 270.7 | MWe |
| Overall Plant Net Power Output | 784.8 | 973.6 | 932.6 | MWe |
| | | | | |
| Total Plant Fuel Consumption (LHV) | 1404.6 | 2388.7 | 2390.7 | MWth |
| Fuel Gas to Combined Cycle Power Plant | 1404.6 | 1478.8 | 1406.3 | MWth |
| Overall Plant Net Electrical Efficiency | 55.9 | 40.8 | 39.1 | % |

The heat rate of the gas turbine when operating on fuel gas diluted primarily with $CO_2$ is higher than operating on syngas diluted primarily with nitrogen. This is because the higher mass flow of fuel gas requires a reduced firing temperature to avoid overloading the gas turbine shaft.

## Economic Analysis

Table 2 – Additional Capital Expenditure (No $CO_2$ Capture)

| **Additional Capital Expenditure** | Ref. | 3-3 | 3-4 | |
|---|---|---|---|---|
| Additional Capital Costs[1] | - | 949 | 1102 | Million US $ |
| Specific Total Investment | 529 | 1401 | 1627 | US $/MWe |
| Costs of Electricity | 30.3 | 44.4 | 49.8 | US $/MWh |

Notes
1. On top of capital expenditure for reference plant of 415 million USD

**Conclusions**

A fuel plant can be built which is $CO_2$ capture ready and used to refuel an existing gas turbine at similar efficiencies and costs to a traditional IGCC without the ability to capture $CO_2$. The prices for natural gas and coal as used in the study means that the cost of electricity produced by such a plant is not competitive with electricity produced from natural gas in a combined cycle. However, there are some parts of the world, most notably North America where the price differential between coal (or petroleum coke) and natural gas would mean that refuelling a natural gas combined cycle with syngas are now commercially attractive.

Despite the lower heat rate of the gas turbine when operating on $CO_2$ contain syngas, the power output of the CCPP is increased and overall efficiency is in line with commercial IGCC's operating on solid feedstock.

Just as in the $CO_2$ capture cases 3-1 and 3-2, the remote fuel plant, case 3-4 is less efficient than the local fuel plant. This is because power cannot be recovered from the expander, as the fuel gas is piped at high pressure and also heat from the fuel plant cannot be used to preheat the fuel gas to the CCPP. This function is carried out by using steam taken from the HRSG of the CCPP, which reduces the overall output of the CCPP when compared with the local case.

| | | |
|---|---|---|
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| **IEA GREENHOUSE GAS R&D PROGRAMME** | Date | : July 2004 |

**Cost Evaluation Case 3.3**

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| | REFERENCE | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 2388.7 | 0.0 | MW |
| Net power output | 973.6 | 0.0 | MW |
| CO2 output | 0.0 | 0.0 | t/h |
| Solid waste output | 1.70 | 1.70 | t/h |
| $CO_2$ emissions | - | - | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidan* | | |
| $CO_2$ emissions | - | | g/kWh |
| Electricity cost | 4.442 | | c/kWh |
| | | | |
| Retrofit year (n) | | 100 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 1165.5 | 0.0 |
| Contingencies | 10.0% | 10.0% |
| | 116.6 | 0.0 |
| Owners costs | 7.0% | 7.0% |
| | 81.6 | 0.0 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **1363.6** | **0.0** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.4 | 0.0 |
| Fuel storage | 10.9 | 0.0 |
| **Total working capital** | **11.3** | **0.0** |

| | REFERENCE | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **MM $/year** |
| **at 100% load factor** | | |
| Fuel | 113.0 | 0.0 |
| Maintenance | 31.6 | 0.0 |
| Chemicals + consumables | 4.2 | 0.0 |
| Insurance and local taxes | 23.3 | 0.0 |
| Waste disposal | 2.7 | 0.0 |
| Operating labour | 3.5 | 0.0 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFEREI | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 85.0 | 0.1 | % |
| Fuel price | 1.50 | 1.50 | $/GJ |
| CO2 price | 167.5 | 167.5 | $/t |
| Waste disposal cost | 184.5 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 30 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 30 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year | 60 | 60 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 167.527 | $/t $CO_2$ |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV)* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 29.82% | |
| Capital | 51.25% | |
| Other costs | 18.92% | |

**CASH FLOW ANALYSIS**

| **Million $** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** |
| **Load Factor** | | | | 45% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% |
| **Equivalent yearly hours** | | | | 3942 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | | | | 170.5 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -50.8 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 |
| Maintenance | 0.0 | 0.0 | 0.0 | -14.2 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 |
| Labour | 0.0 | 0.0 | 0.0 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.9 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | -1.2 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 |
| **Fixed Capital Expenditures** | 0.0 | -545.5 | -818.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -11.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -545.5 | -818.2 | 64.1 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 |
| Total Cash Flow (cumulated) | 0.0 | -545.5 | -1363.6 | -1299.5 | -1133.1 | -966.8 | -800.4 | -634.0 | -467.6 | -301.3 | -134.9 | 31.5 | 197.9 | 364.2 | 530.6 |

| **Million $** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** | |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | 322.0 | | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | -96.0 | | -624.1 |
| Maintenance | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | -26.9 | | -174.8 |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | | -23.9 |
| Chemicals & consumables | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | | -23.1 |
| Waste disposal | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | -2.3 | | -15.2 |
| Insurance and local taxes | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | -23.3 | | -159.0 |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 | -1065.5 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.3 | -7.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | 0.0 | 0 |
| Total Cash Flow (yearly) | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 166.4 | 11.3 | |
| Total Cash Flow (cumulated) | 697.0 | 863.4 | 1029.7 | 1196.1 | 1362.5 | 1528.8 | 1695.2 | 1861.6 | 2028.0 | 2194.3 | 2360.7 | 2527.1 | 2693.5 | 2704.8 | -2092.7 |

| | |
|---|---|
| Version | 4.5 |
| Date | : July 2004 |

# IEA GREENHOUSE GAS R&D PROGRAMME

**Cost Evaluation Case 3.4**

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| | REFERENCE | RETROFIT | |
|---|---|---|---|
| **Production** | | | |
| Fuel feedrate | 2390.7 | 0.0 | MW |
| Net power output | 932.6 | 0.0 | MW |
| CO2 output | 0.0 | 0.0 | t/h |
| Solid waste output | 1.84 | 1.70 | t/h |
| $CO_2$ emissions | - | - | g/kWh |
| | | | |
| **Reference plant data** | *For calculation of cost of emission avoidan* | | |
| $CO_2$ emissions | - | | g/kWh |
| Electricity cost | 4.984 | | c/kWh |
| | | | |
| Retrofit year (n) | | 100 | - |
| Retrofit Expenditure year (n-2) | | 20% | - |
| Retrofit Expenditure year (n-1) | | 45% | - |
| Retrofit Expenditure year (n) | | 35% | - |

| | REFEREN | RETROFIT |
|---|---|---|
| **Capital Cost** | **Million $** | **Million $** |
| Installed costs | 1296.8 | 0.0 |
| Contingencies | 10.0% | 10.0% |
| | 129.7 | 0.0 |
| Owners costs | 7.0% | 7.0% |
| | 90.8 | 0.0 |
| Retrofit escalation basis year | | 9 |
| Retrofit Expenditure escalation yearly | | 0% |
| Retrofit Expenditure escalation | | 0.0% |
| **Total capital cost** | **1517.2** | **0.0** |
| | | |
| **Working Capital** | | |
| Chemicals storage | 0.4 | 0.0 |
| Fuel storage | 10.9 | 0.0 |
| **Total working capital** | **11.3** | **0.0** |

| | REFERENCE | RETROFIT |
|---|---|---|
| **Operating Costs** | **MM $/year** | **/M $/year** |
| **at 100% load factor** | | |
| Fuel | 113.1 | 0.0 |
| Maintenance | 34.6 | 0.0 |
| Chemicals + consumables | 4.3 | 0.0 |
| Insurance and local taxes | 25.9 | 0.0 |
| Waste disposal | 3.0 | 0.0 |
| Operating labour | 3.5 | 0.0 |
| | | |
| **Decommissioning cost** | 0 | 0 |

| | REFERE | RETROFIT | |
|---|---|---|---|
| **Economic parameters** | | | |
| Discount rate | 10.0 | | % |
| Load factor | 85.0 | 0.1 | % |
| Fuel price | 1.50 | 1.50 | $/GJ |
| CO2 price | 167.5 | 167.5 | $/t |
| Waste disposal cost | 184.5 | 184.5 | $/t |
| Insurance and local taxes | 2% | 2% | of installed cost/y |
| Number of operators | 30 | 30 | |
| Cost per operator | 75.0 | 75.0 | $k/y |
| Administration | 56% | 56% | of operators cost |
| Fuel storage | 30 | 30 | days |
| Chemicals storage | 30 | 30 | days |
| Start up time | 3 | 3 | months |
| Retrofit down time | | 1 | months |
| Load factor, remainder year | 60 | 60 | % |

| | | |
|---|---|---|
| **Results summary** | | |
| Emission avoidance cost | 167.527 | $/t $CO_2$ |
| *(Note: Type 'Tools' Solver' 'Solve' to calculate* | | |
| *the CO2 emission avoidance cost that gives a zero NPV* | | |
| NPV | 0.00 | M$ |
| IRR | 10.00% | |
| | | |
| **Breakdown of c/kWh cost** | | |
| Fuel | 27.78% | |
| Capital | 53.03% | |
| Other costs | 19.20% | |

**CASH FLOW ANALYSIS**

| Million $ | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **000** | **00** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| **Load Factor** | | | | 45% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% |
| **Equivalent yearly hours** | | | | 3942 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 |
| **Expenditure Factor** | 0% | 40% | 60% | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | |
| Electricity | | | | 183.2 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 |
| CO2 revenues(based on power output retrofit case) | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Operating Costs** | | | | | | | | | | | | | | |
| Fuel | 0.0 | 0.0 | 0.0 | -50.9 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 |
| Maintenance | 0.0 | 0.0 | 0.0 | -15.6 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 |
| Labour | 0.0 | 0.0 | 0.0 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 |
| Chemicals & consumables | 0.0 | 0.0 | 0.0 | -1.9 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 |
| Waste disposal | 0.0 | 0.0 | 0.0 | -1.3 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 |
| Insurance and local taxes | 0.0 | 0.0 | 0.0 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 |
| **Fixed Capital Expenditures** | 0.0 | -606.9 | -910.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | -11.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Decommissioning Cost** | | | | | | | | | | | | | | |
| Total Cash Flow (yearly) | 0.0 | -606.9 | -910.3 | 72.7 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 |
| Total Cash Flow (cumulated) | 0.0 | -606.9 | -1517.2 | -1444.5 | -1259.5 | -1074.6 | -889.6 | -704.6 | -519.6 | -334.7 | -149.7 | 35.3 | 220.3 | 405.2 |

| Million $ | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** | **26** |
| **Load Factor** | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | 85% | |
| **Equivalent yearly hours** | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | 7446 | |
| **Expenditure Factor** | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | |
| Electricity | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | 346.1 | |
| CO2 revenues(based on power output retrofit case) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| **Operating Costs** | | | | | | | | | | | | | | | |
| Fuel | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | -96.1 | |
| Maintenance | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | -29.4 | |
| Labour | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | -3.5 | |
| Chemicals & consumables | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | -3.6 | |
| Waste disposal | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | -2.5 | |
| Insurance and local taxes | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | -25.9 | |
| **Fixed Capital Expenditures** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.00 |
| **Working Capital** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.3 |
| **Decommissioning Cost** | | | | | | | | | | | | | | | 0.0 |
| Total Cash Flow (yearly) | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 185.0 | 11.3 |
| Total Cash Flow (cumulated) | 590.2 | 775.2 | 960.2 | 1145.1 | 1330.1 | 1515.1 | 1700.1 | 1885.0 | 2070.0 | 2255.0 | 2440.0 | 2624.9 | 2809.9 | 2994.9 | 3006.2 |