Evaluating technology options to mitigate greenhouse gas emissions

IEAGHG Technical Report

2017-02

February 2017

Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS

IEA GREENHOUSE GAS R&D PROGRAMME

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ACKNOWLEDGEMENTS AND CITATIONS

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The report should be cited in literature as follows:

'IEAGHG, "Techno-Economic Evaluation of SMR Based Standalone (Merchant) Plant with CCS", 2017/02, February, 2017.'

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Techno-Economics of Deploying CCS in a SMR Based Hydrogen Production using NG as Feedstock/Fuel

Key Messages

- IEAGHG have systematically evaluated the performance and cost of integrating CCS in various energy intensive industries. To date, the programme looked at deploying CCS in the cement, iron and steel, pulp and paper industry, whilst studies in the oil refining, methanol and ammonia/urea production from NG underway.

- Hydrogen is a key raw material to other energy intensive industries. Globally, nearly 90% of the hydrogen produced is consumed by the ammonia, methanol and oil refining industries. In the future, hydrogen could also play an important role in the decarbonisation of space heating (i.e. industrial, commercial, building and residential heating) and transport fuel (i.e. use of fuel cell vehicles).

- Currently, the steam methane reformer (SMR) is the leading technology for H_2 production from natural gas or light hydrocarbons. Modern SMR based hydrogen production facilities have achieved efficiencies that could reduce CO_2 emissions down to nearly 10% above its theoretical minimum. Further reduction of CO_2 emissions from hydrogen production would only be possible by the integration of CCS.

- This study provides an up-to-date assessment of the performance and costs of a modern SMR based H_2 plant without and with CCS producing 100,000 Nm^3/h H_2 and operating as a merchant plant (i.e. standalone plant - without any integration to an industrial complex).

- Unlike other studies in the series, the capture of CO_2 from an SMR plant is a commercial operation. This is one of the main sources of industrial and food grade CO_2 in the market globally. However, only 3 sites around the world have demonstrated the integration of CO_2 capture with CO_2 transport and storage. These include (a.) Port Arthur Project in the USA, (b.) Quest Project in Canada, and (c.) Tomakomai Project in Japan.

- This study presents the economics of deploying CCS in an SMR based hydrogen plant capturing CO_2 from the (a.) shifted syngas, (b.) PSA's tail gas or (c.) SMR's flue gas. Each capture option was evaluated using IEAHG's standard assessment criteria against a Base Case (i.e. H_2 plant without CCS).

- The Base Case consists of: (a.) feedstock pre-treatment, (b.) pre-reformer, (c.) primary reformer, (d.) high temperature shift reactor and (e.) pressure swing absorption or PSA in single train arrangement producing 100,000 Nm^3/h of H_2 (purity >99.9%). It consumes about 14.21 MJ of NG and emits about 0.81 kg of CO_2 per Nm^3 H_2 produced. It has a surplus of ~9.9MWe electricity which is exported to the grid.

- The current industry standard for capturing CO_2 from an SMR Based H_2 plant is the capture of CO_2 from the shifted syngas using MDEA solvent. Four other CO_2 capture options were then evaluated as part of this study. These include: the use of H_2 rich burner in conjunction with capture of CO_2 from shifted syngas using MDEA; the capture of CO_2 from PSA's tail gas using MDEA, or the use of Cryogenic and Membrane Separation; and the capture of CO_2 from flue gas using MEA. These options involve the CO_2 capture rate in the range of 56% to 90%.

- For all the CCS cases, the addition of the CO_2 capture increases the total plant cost by 18% to 79% compared to the Base Case. This corresponds to an additional total capital requirement) of around €40 to €176 million (Q4 2014 estimates).

- For all bar one of the capture options considered, the incorporation of CO_2 capture increases the natural gas consumption by 0.46 to 1.41 MJ/Nm^3 H_2. Similarly, all options with CO_2 capture resulted in a reduction of the surplus electricity that could be exported to the grid. These changes resulted to an increase in the operating cost of hydrogen production by 18% to 33% compared to the Base Case.

- Adding CCS to an SMR based H_2 plant results to an increase in the Levelised Cost of Hydrogen between € 0.021 and € 0.051 per Nm^3 H_2 (from € 0.114 per Nm^3 for the Base Case). This corresponds to a CO_2 avoidance cost (CAC) of between €47 and €70 per tonne of CO_2.

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEAGHG) has undertaken a series of studies evaluating the performance and cost of capturing CO_2 from the different energy intensive industries. The most recent of these studies is the hydrogen production from steam methane reforming (SMR) using natural gas as feedstock and fuel.

Hydrogen is a key raw material to other industries. Globally, nearly 90% of the hydrogen or HyCO gas produced is used by the ammonia, methanol and oil refining industries. In the future, hydrogen could play an important role in the decarbonisation of space heating (i.e. industrial, commercial, building and residential heating) and transport fuel (i.e. use of fuel cell vehicles).

The economics of hydrogen production are determined by several factors such as the cost and quality of the feedstock, and utilities. Around 90% of the feedstock used in the production of hydrogen are from fossil fuels i.e. natural gas, fuel oil and coal[1]. Other feedstocks could include other hydrocarbons such as refinery off-gases, LPG, naphtha, petcoke, asphalts, vacuum tars, and others.

The conversion of fossil fuels to hydrogen also produces a significant amount of CO_2 as a by-product. Environmental concerns regarding the reduction of CO_2 emissions from energy intensive industries (including hydrogen production) should be expected in the future following the Paris Agreement.

Currently, the steam methane reforming (SMR) is the leading technology for H_2 production from natural gas or light hydrocarbons. Most of the modern SMR based hydrogen production facilities can now achieve energy efficiency levels that reduce CO_2 emissions down to nearly 10% above its theoretical minimum. Further reduction of CO_2 emissions from hydrogen production could only be achieved by the integration of CO_2 capture and storage (CCS) in the process scheme.

[1] Coal is mainly used as feedstock to produce hydrogen or HYCO in China and India.

To understand the cost of deploying CCS in the hydrogen production plant, IEAGHG commissioned Amec Foster Wheeler to undertake the "Techno-Economic Evaluation of Hydrogen Production with CO_2 Capture and Storage".

This study aimed to provide baseline information presenting the performance and costs of incorporating the CO_2 capture technologies to a SMR based hydrogen plant operating as merchant plant (as a standalone plant).

The basis of the design of the hydrogen production process are presented in the main report. These are briefly described in this overview. The selection of technology options for CO_2 capture is based on the available information and performance data that could be provided by equipment manufacturers and suppliers.

It should be noted that the study does not aim to provide a definitive comparison of different technologies or technology suppliers because such comparisons are strongly influenced by specific local constraints and market factors, which can be subject to rapid changes.

Scope of Work

Study Cases

This study evaluated the design, performance, and cost of a "greenfield" state-of-the-art SMR plant producing 100,000 Nm^3/h of hydrogen using natural gas as feedstock and fuel; and operating in merchant plant mode (i.e. it is a standalone facility without any integration to other processes within an industrial complex).

Specifically, this study is aimed to assess the following cases without and with CCS:

- Base Case: SMR Plant equipped with Feedstock Pre-treatment, Pre-reforming, High Temperature shift and PSA
- Case 1A: SMR with capture of CO_2 from the shifted syngas using MDEA[2]
- Case 1B: SMR with burners firing H_2 rich fuel and capture of CO_2 from the shifted syngas using MDEA
- Case 2A: SMR with capture of CO_2 from the PSA tail gas using MDEA
- Case 2B: SMR with capture of CO_2 from the PSA tail gas using cryogenic and membrane separation
- Case 03: SMR with capture of CO_2 from the flue gas using MEA[3]

All of these cases covers the different options where CO_2 could be captured within the H_2 plant (i.e. capture of CO_2 from the shifted syngas, PSA tail gas or SMR flue gas), demonstrating an overall CO_2 capture rate ranging between 50 and 90%.

[2] Chemical absorption using activated MDEA is currently the state of the art technology for capturing CO_2 from shifted syngas due to the high partial pressure of CO_2 in the gas stream. (i.e. 16%$_v$ CO_2 at 2.5 MPa for the shifted syngas and 51%$_v$ at 0.2 MPa for the PSA's tail gas).

[3] Chemical absorption using MEA is considered as a standard technology normally used in capturing CO_2 from flue gas (i.e. 21%$_v$ and 0.1 MPa) as this could serve as a good basis for comparison in future studies.

Basis of Design

SMR Based H_2 Plant

The natural gas is initially pre-treated to remove any sulphur and chlorine present in the feedstock. This prevents any poisoning of the catalysts downstream. This is mixed with process steam and pre-reformed in an adiabatic reactor to convert any light hydrocarbons (mainly converting any C2+ and olefins) before being fed into the primary reformer.

The primary reformer of the H_2 plant (without capture) is based on tubular reformer with terraced wall firing. The syngas produced should consists of CO_2, CO, H_2 and residual CH_4.

The syngas produced from the reformer is then fed into the high temperature shift (HTS) reactor to convert the CO to H_2 thus producing a syngas with residual CO of around 2.5-3%v. This is then fed into the PSA where around 85-90% of H_2 with a purity of 99.9+% are recovered. The PSA tail gas is collected and fed into the burners of the SMR as its primary fuel.

HP Steam is generated by recovering heat from both the convective section of the flue gas and the cooling of the syngas (before and after the shift reactor). The plant is optimized to minimise the amount of excess steam generated by the plant. Any excess steam is delivered to the power island, which consists of a condensing steam turbine, to generate electricity that is exported to the grid.

In this type of SMR plant, all of the CO_2 is emitted from the flue gas of the steam reformer. However, it should be noted that the CO_2 is produced from the following processes:

- CO_2 produced during the reforming and water-gas shift reaction;
- CO_2 produced during the combustion of the residual CO in the PSA tail gas and the natural gas (as supplementary fuel) in the SMR furnace.

Based on these processes, it could be gathered that the CO_2 could be captured from three possible locations:

- the shifted syngas (Option 1),
- the PSA tail gas (Option 2), and
- the SMR flue gas (Option 3).

The capture of CO_2 from an SMR plant is not a new technology. This has been done in various plants worldwide. The capture of CO_2 from the syngas of the SMR is commercially deployed. The current state-of-the-art is based on chemical absorption technology. However, what's new is the integration of capture technologies with CO_2 transport and storage. Additionally, new and novel CO_2 capture technologies are also being developed and demonstrated.

The Part 2 of the Technical Review (Task 1) briefly reviewed the different technology options that is available in the market to capture CO_2 from the different gas streams of the H_2 plant.

Technical Design Basis

The key assumptions used in the evaluation of the performance of the plant are as follows:

- Plant Location:

  The site is a "greenfield" location situated in the North East coast of The Netherlands, with no major site preparation required. No restrictions on plant area and no special civil works or constraints on the delivery of equipment are assumed. Rail lines, roads, fresh water supply and high voltage electricity transmission lines, high pressure natural gas pipeline are considered available at plant battery limits.

- Plant Capacity

  The plant is designed to produce 100,000 Nm^3/h of high purity H_2. Any excess HP steam produced and not used by the plant are converted to electricity. This is exported to the grid.

- Capacity Factor

  The study assumes a capacity factor of 70% for its first year of operation and 95% for the rest of the life of the plant. This translates to annual operating hours of 8322 h/y.

- Ambient Conditions:

  Main climatic and meteorological data are listed below.

⇒ Atmospheric pressure	101.3	kPa
⇒ Average ambient temperature	9	^oC
⇒ Average relative humidity	80	%

- Natural Gas (NG) specification

  The natural gas (used as feedstock and fuel) is delivered to the battery limit from a high pressure pipeline. The main specifications of the natural gas is summarized in the main report.

- Cooling Water

  The primary cooling water system used by the plant is based on once through seawater cooling system. The average supply temperature is set at 12^oC. The average return temperature is set at 19^oC.

- Product Specifications

  The H_2 produced by the plant has a purity of at least 99.5% (min). The CO and CO_2 content should be limited to 10 ppm max. It should be free of other impurities such as H_2S, HCl, COS, HCN and NH_3. The H_2 is sold and delivered to industrial consumers. The pressure and temperature at the battery limit is at 2.5MPa and 40^oC respectively.

The CO_2 produced by the CO_2 capture plant has a purity of at least 99% (min). The moisture content is less than 10 ppmv. The CO_2 product is delivered to a pipeline for use in EOR. The pressure and temperature at the battery limit is at 11.0 MPa and 30°C (max).

General Criteria for Economic Evaluation

Where applicable, the criteria for economic evaluation used in this study is based on the information retrieved from IEAGHG document "Criteria for Technical and Economic Assessment of Plants with Low CO_2 Emissions" Version C-6, March 2014. Other key criteria and assumptions relevant to the operation of the hydrogen plant are based on the information provided by Amec Foster Wheeler.

The criteria used in the evaluation of the cost of hydrogen production and CO_2 avoided cost are summarized below:

- Plant Life

  The plant is design for an economic life of 25 years.

- Financial leverage (debt / invested capital)

  All capital requirements are treated as debt, i.e. financial leverage equal to 100%.

- Discount Rate

  Discounted cash flow analysis is used to evaluate the levelised cost of H_2 production (LCOH) and CO_2 avoidance cost (CAC). The discount rate of 8% is assumed.

- Inflation Rate

  Not considered in the discounted cash flow analysis.

- Depreciation

  Not considered in the discounted cash flow analysis. The results presented in this study is reported on Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) basis.

- Design and Construction Period

  The design and construction period and the curve of capital expenditure assumed in this study is presented below:
  - ⇒ Construction period: 3 years
  - ⇒ Curve of capital expenditure

Year	Investment cost %
1	20
2	45
3	35

- Decommissioning Cost

  This is not included in the discounted cash flow analysis. The salvage value of equipment and materials is normally assumed to be equal to the costs of dismantling and site restoration, resulting to a zero net cost for decommissioning.

- Estimate accuracy

  The estimate is based on AACE Class 4 estimate (with accuracy in the range of +35%/-15%), using 4Q-2014 price level, in euro (€).

Definition of Cost

Capital Cost

The capital cost is presented as the Total Plant Cost (TPC) and the Total Capital Requirement (TCR).

TPC is defined as the installed cost of the plant, including project contingency. This is broken down into:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency

TCR is defined as the sum of:

- Total plant cost (TPC)
- Interest during construction
- Owner's costs
- Spare parts cost
- Working capital
- Start-up costs

For each of the cases the TPC has been determined through a combination of licensor/vendor quotes, the use of Amec Foster Wheeler's in-house database and the development of conceptual estimating models, based on the specific characteristics, materials and design conditions of each item of equipment in the plant. The other components of the TCR have been estimated mainly as percentages of the TPC of the plant. These are summarized in Section 3.5.

Fixed Operating Cost

The fixed operating cost includes the following:

- direct labor cost
- administrative and general overhead cost
- annual operating and maintenance cost
- insurance
- local taxes and fees

Variable Operating Cost

The variable operating cost include the consumptions of the following key items:

- Feedstock (natural gas)
- Raw water make-up
- Catalysts
- Chemicals

Levelised Cost of Hydrogen

The Levelised Cost of Hydrogen (LCOH) is used to calculate the unit cost of producing hydrogen over their economic lifetime. This is defined as the price of hydrogen which enables the present value from all sales of hydrogen (including the additional revenue from the sale of electricity) over the economic lifetime of the plant to equal the present value of all costs of building, maintaining and operating the plant over its lifetime.

The method of calculation is based on a discounted cash flow analysis. This is similar to how the Levelised Cost of Electricity (LCOE) are calculated in other IEAGHG studies, except that it is necessary to take into account the revenues from the sale of electricity as co-product.

The LCOH in this study is calculated assuming constant (in real terms) prices for fuel and other costs and constant operating capacity factors throughout the plant lifetime, apart from lower capacity factors in the first year of operation.

Cost of CO_2 Avoidance

The CO_2 avoidance cost (CAC) were calculated by comparing the CO_2 emissions per Nm^3 H_2 and the LCOH of plants with capture and a reference plant without capture.

$$CO_2 \text{ Avoidance Cost (CAC)} = \frac{LCOH_{CCS} - LCOH_{Reference}}{CO_2Emissions_{\ Reference} - CO_2Emissions_{\ CCS}}$$

where:

- CAC is expressed in € per tonne of CO_2
- LCOH is expressed in € per Nm^3/h H_2
- CO_2 emission is expressed in tonnes of CO_2 per Nm^3 of H_2

Key Assumptions

The assumptions used to calculate of the total capital requirements include:

- Spare parts cost

  0.5% of the TPC is assumed to cover spare part costs. It is also assumed that spare parts have no value at the end of the plant life due to obsolescence.

- Start-up cost

  The start-up costs consist of the following items:

  ⇒ 2% of TPC to cover any modifications to the plant that would bring the different units to full capacity.

⇒ 25% of the monthly feedstock and fuel cost to cover any inefficient operation during the start-up period.

⇒ 3 months of the operating labour and maintenance labour cost to cover manpower and personnel training cost.

⇒ 1 month of chemicals, catalyst and waste disposal cost and maintenance materials cost.

- Owner's cost

  Owner's costs cover the costs of feasibility studies, surveys, land purchase, construction or improvement to the infrastructure beyond the site boundary (i.e. road, port, railway, water supply, etc..), owner's engineering staff costs, permitting and legal fees, arranging financing and other miscellaneous costs.

  Owner's costs are assumed to be all incurred in the first year of construction, allowing for the fact that some of the costs would be incurred before the start of construction.

  7% of the TPC is assumed to cover the Owner's cost and fees.

- Interest during construction

  Interest during construction is calculated from the plant construction schedule and the interest rate is assumed to be the same as the discount rate. Expenditure is assumed to take place at the end of each year and interest during construction payable in a year is calculated based on money owed at the end of the previous year.

- Working capital

  The working capital includes inventories of fuel and chemicals (materials held in storage outside of the process plants). Storage for 30 days at full load is considered for chemicals and consumables. It is assumed that the cost of these materials are recovered at the end of the plant life.

The assumptions used to calculate of the fixed operating cost are as follows:

- Direct labour cost

  The yearly cost of the direct labour is calculated assuming an average salary of 60,000 €/y. The number of personnel engaged in the plant's operation is estimated for each plant type where 5 shift working pattern is considered.

  This study assumes 38 personnel needed for the Base Case and 5 more additional personnel for all cases with CO_2 capture.

- Admin and general overhead cost (indirect labour cost)

  Generally, the overhead cost is dependent on the company's organization structure and complexity of its operation. This normally covers functions which are not directly involved in the daily operation of the plant.

These functions could include:
⇒ Management;
⇒ Administration;
⇒ Personnel services;
⇒ Clerical staff
⇒ Technical services;
⇒ R&D staff

This study assumes that the indirect labour cost is equal to 30% of the direct labour and maintenance labour cost.

- Annual operating and maintenance cost

  A precise evaluation of the cost of maintenance would require a breakdown of the costs amongst the numerous components and packages of the plant. Since these costs are all strongly dependent on the type of equipment selected and their statistical maintenance data provided by the selected vendors. This kind of evaluation of the maintenance cost is premature for this type of study.

  For this reason the annual maintenance cost of the plant is estimated as a percentage of the TPC. 1.5% is assumed for all cases. This generally applies to all of the major processes, utilities and off-sites.

  Additionally, estimates can be separately expressed as maintenance labour and maintenance materials. A maintenance labour to materials ratio of 40:60 can be statistically considered for this study.

- Insurance cost

  0.5% of the TPC is assumed to cover the insurance cost.

- Local taxes and fees

  0.5% of the TPC is also assumed to cover the local taxes and fees.

The key assumptions used in estimating the variable operating cost are as follows:

- The assumed prices of the consumables and miscellaneous items are presented in Table 1.

Table 1: Assumed prices for consumables and other miscellaneous items

Item	Unit	Cost	Sensitivity Range
Natural gas	€/GJ (LHV)	6	2 to 18
Raw process water	€/m^3	0.2	-
Electricity	€/MWh	80	20 to 100
CO_2 transport and storage	€/t CO_2 stored	10	-20 to 40
CO_2 emission cost	€/t CO_2 emitted	0	0 to 100

The Transport and storage cost is specified in accordance to the range of costs reported by the European Zero Emissions platform's report [ZEP 2011][4]. The sensitivity to the transport and storage costs are assessed to cover the lower or negative cost for EOR application (due to revenues for sale of CO_2) or higher cost – in case of off-shore CO_2 storage or with long distance CO_2 transport requirements.

- Chemical and Catalyst Cost

  The cost of chemicals is assumed fixed at an annual cost of €100,000 for all cases. This generally accounts for the cost of chemicals used in the treatment of demi-water, process water, boiler feed water, cooling water, and others.

  The catalyst cost which covers the catalyst used in the feedstock pre-treatment, pre-reformer, reformer and shift reactor is also fixed at €320,000 per year (except for Case 2B which is set at €405,000 per year).

Findings of the Study

Plant Performance

Figures 1 to 6 present the simplified block flow diagram of the different cases evaluated in this study. A summary of the performance of the SMR based H_2 plants with and without capture is given in Table 2.

For Cases 1A, 2A and 3, the capture of CO_2 are based on chemical absorption technology; demonstrating an overall CO_2 capture rate from 55% to 90%. This results to an increase in the natural gas consumption from 0.45 to 1.40 MJ/Nm^3 H_2 to generate the steam required for the solvent regeneration. The steam is obtained from a back-pressure steam turbine. Additional electricity required by the CO_2 capture system results in a significant reduction of electricity that could be exported to the grid (with Case 2A requiring additional import of ~1.1MWe of electricity).

For Case 1B, the overall CO_2 capture rate is increased to about 64% (as compared to Case 1A at 54%). This is achieved by burning H_2 rich fuel instead of natural gas as a supplementary fuel for the SMR burners. The H_2 rich fuel is obtained from the sweet syngas coming from the MDEA CO_2 capture plant. For this case, the raw syngas production capacity of the SMR and its associated equipment is enlarged by around 27% to maintain a fixed production capacity of 100,000 Nm^3/h H_2.

For Case 2B, the CO_2 is captured from the PSA tail gas using low temperature CO_2 separation and membrane technology. In this case, the natural gas consumption has been reduced by 0.03 MJ/Nm^3 H_2 as compared to the Base Case. The electricity required by the CO_2 capture plant also reduced the net amount of electricity that could be exported.

It should be noted that the technology used in Case 2B could be re-configured to increase the hydrogen production by around 5%. However, for this study, the production rate was fixed at 100,000 Nm^3/h and to maximise the CO_2 capture rate, this option was not considered.

[4] Zero Emission Platform (2011). "The Cost of CO_2 Transport" and "The Cost of CO_2 Storage"

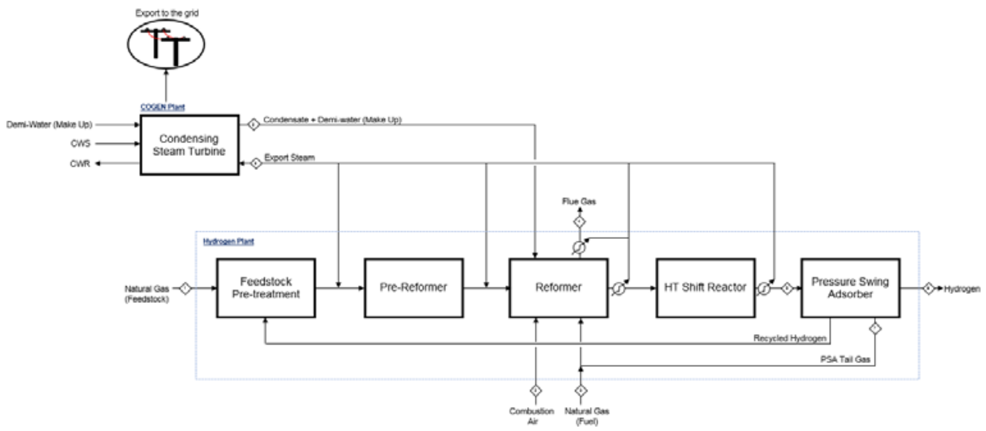

Figure 1: Base Case - SMR plant without CO_2 capture producing 100,000 Nm^3/h H_2.

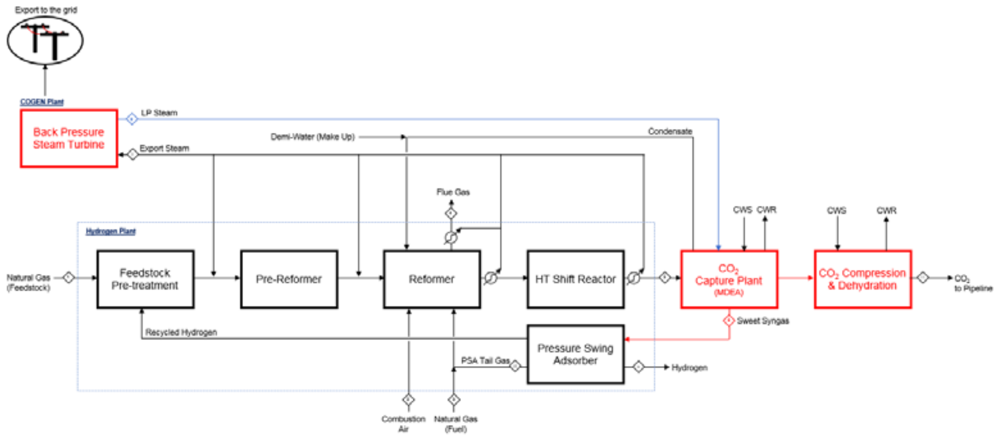

Figure 2: Case 1A - SMR Plant with capture of CO_2 from shifted syngas using MDEA

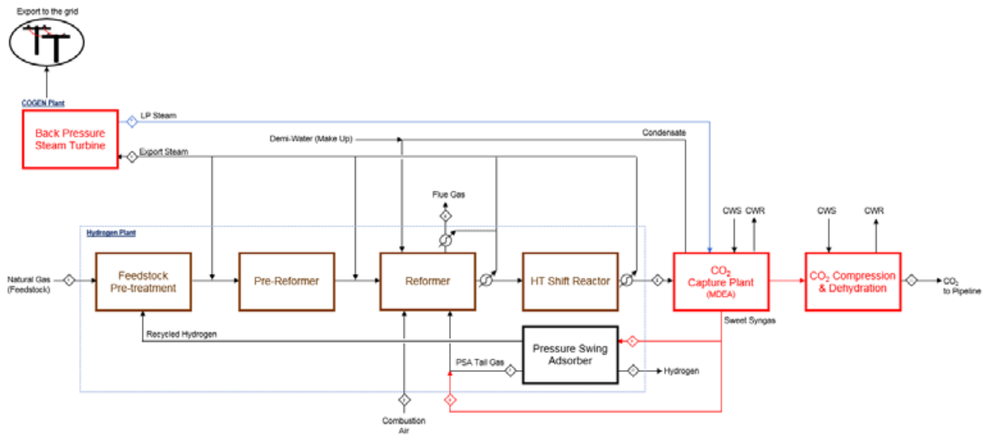

Figure 3: Case 1B - SMR Plant with H_2 rich burners and capture of CO_2 from shifted syngas using MDEA

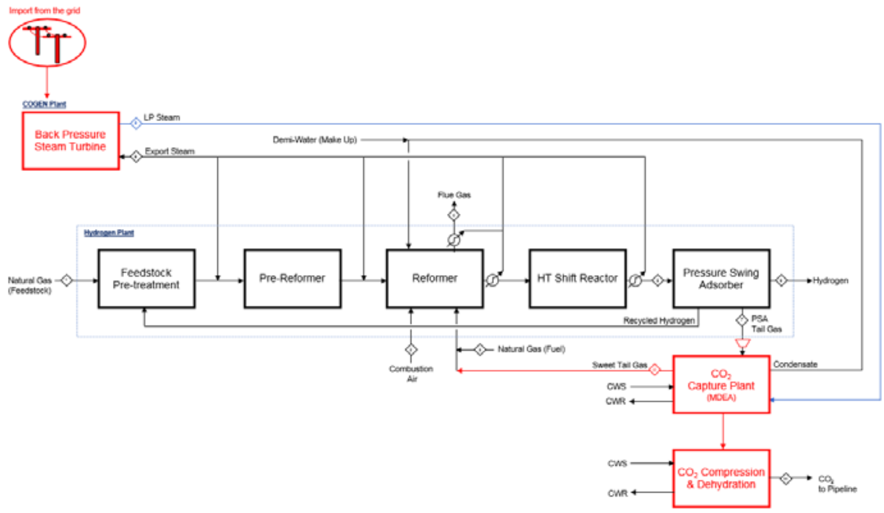

Figure 4: Case 2A - SMR plant with capture of CO_2 from PSA tail gas using MDEA

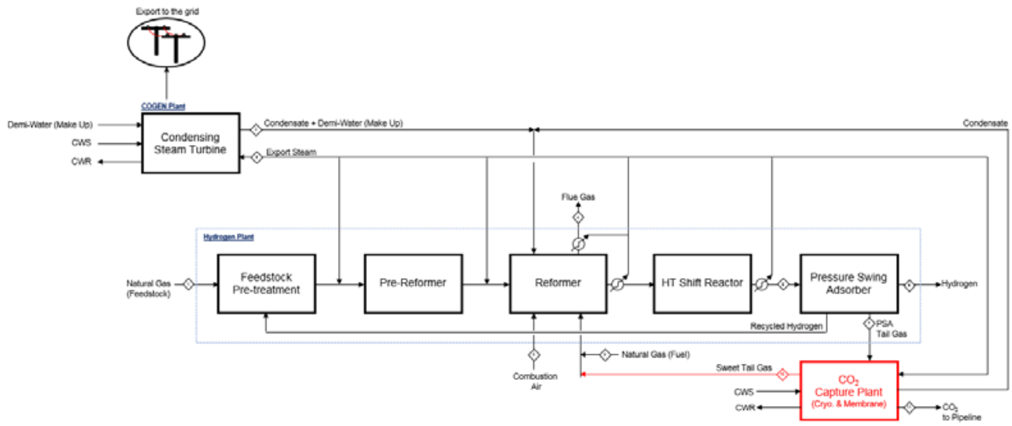

Figure 5: Case 2B - SMR Plant with capture of CO_2 from PSA tail gas using low temperature and membrane separation

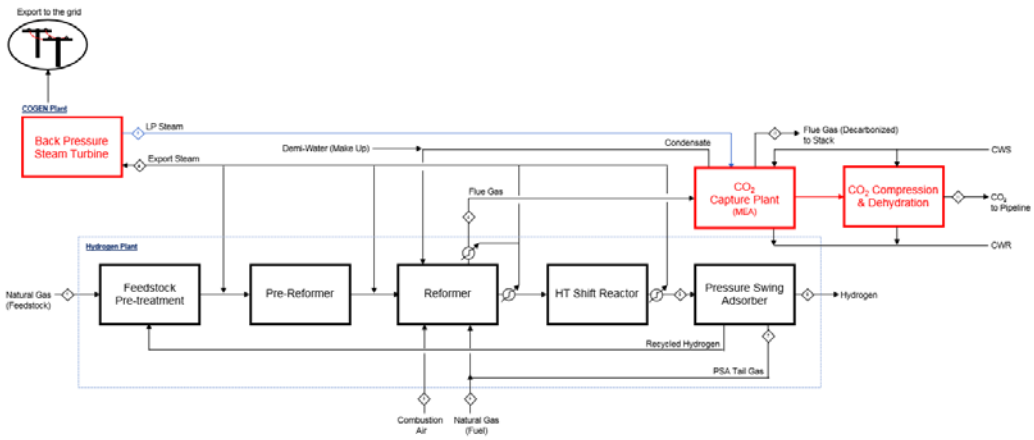

Figure 6: Case 3 - SMR Plant with capture of CO_2 from SMR flue gas using MEA

Table 2: Plant Performance Summary

		Base Case	Case 1A	Case 1B	Case 2A	Case 2B	Case 3
Inlet Stream							
NG to Feedstock	t/h	26.231	26.262	33.333	26.231	26.231	26.231
NG to Fuel	t/h	4.332	5.300	0.000	5.597	4.264	7.347
LHV	MJ/kg	46.50	46.50	46.50	46.50	46.50	46.50
Total Energy Input (A)	MW	394.77	407.68	430.55	411.11	393.89	433.72
Outlet Stream							
H2 to B.L.	t/h	8.994	8.994	8.994	8.994	8.994	8.994
	Nm^3/h	100,000	100,000	100,000	100,000	100,000	100,000
LHV	MJ/kg	119.96	119.96	119.96	119.96	119.96	119.96
Total Energy in Product (B)	MW	299.70	299.70	299.70	299.70	299.70	299.70
Power Balance							
Gross Power Output from COGEN Plant	MWe	11.500	6.700	8.000	6.900	11.000	11.700
H2 Plant	MWe	-1.216	-1.257	-1.582	-1.264	-1.216	-1.314
COGEN Plant Auxiliaries, Utilities, BOP	MWe	-0.366	-0.377	-0.440	-0.397	-0.511	-1.677
CO2 Capture Plant	MWe	NA	-0.569	-0.717	-3.435	-8.989	-2.001
CO2 Compression and Drying	MWe	NA	-3.005	-3.719	-2.874	(See note below)	-6.282
Export Power to the Grid (C)	MWe	9.918	1.492	1.542	-1.070	0.284	0.426
Specific Consumption							
NG to Feedstock	MJ/Nm^3 H2	12.197	12.212	15.500	12.197	12.197	12.197
NG to Fuel	MJ/Nm^3 H2	2.014	2.465	-	2.603	1.983	3.416
Total (Feedstock + Fuel)	MJ/Nm^3 H2	14.212	14.676	15.500	14.800	14.180	15.614
Plant Performance							
Specific CO2 Emissions	kg/Nm^3 H2	0.8091	0.3704	0.2918	0.3870	0.3772	0.0888
Specific CO2 Captured	kg/Nm^3 H2	NA	0.4660	0.5899	0.4556	0.4289	0.8004
Overall CO2 Capture Rate (Case Specific)		NA	55.7%	66.9%	54.1%	53.2%	90.0%
Overall CO2 Avoided (as compared to Base Case)		NA	54.2%	63.9%	52.2%	53.4%	89.0%

Note: CO_2 compression and drying included in the CO_2 capture plant

Economic Evaluation

Capital Cost

The capital costs of the plants are summarised in Table 3 and the breakdown of the total plant cost are given in Figure 7.

To include the partial capture of CO_2 from an SMR plant (i.e. CO_2 capture rate of 53-65%), the increase in the specific total plant cost per Nm^3/h of H_2 are in the range of 18-42% as compared to the Base Case. On the other hand, to capture about 90% of CO_2 from an SMR plant, the increase in the specific capital cost is about 79% as compared to the Base Case.

Table 3: Capital Cost of SMR Based H_2 Plant

	Total Plant Cost (TPC) (million €)	Total Capital Requirement (TCR) (million €)	% Increase to the TPC as compared to Base Case
Base Case	170.95	222.89	
CO_2 Capture from Shifted Syngas			
Case 1A	201.80	263.91	18.0%
Case 1B	228.48	298.68	33.7%
CO_2 Capture from PSA Tail Gas			
Case 2A	226.07	295.21	32.2%
Case 2B	241.44	313.87	41.2%
CO_2 Capture from Flue Gas			
Case 3	305.33	398.48	78.6%

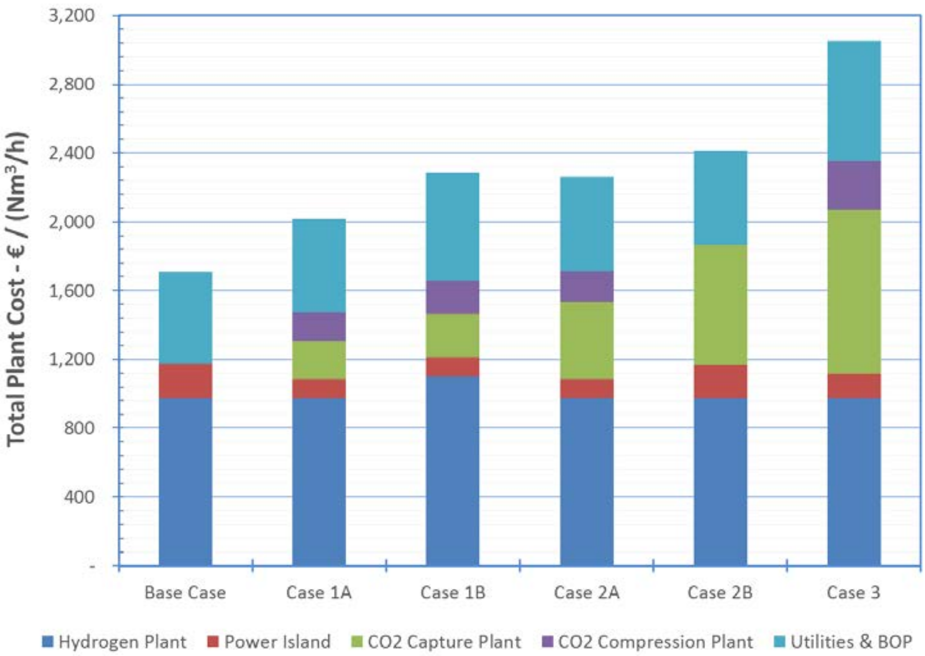

Figure 7: Specific Total Plant Cost - SMR Based H_2 Plant

Operating Cost

The operating cost (OPEX) of the plant includes the costs for: labour, O&M, feedstock, fuel, catalyst, and chemicals. Table 4 summarises the annual OPEX for all the different cases considered.

From these results, it could be noted that the biggest factors that could increase the OPEX of the plant with CO_2 capture are the cost of feedstock/fuel, maintenance, and the loss of revenue from the sale of electricity.

Table 4: Operating Cost of SMR Based H_2 Plant

ANNUAL O&M COST						
	Base Case €/year	Case 1A €/year	Case 1B €/year	Case 2A €/year	Case 2B €/year	Case 3 €/year
Fixed Costs						
Direct labour	2,280,000	2,580,000	2,580,000	2,580,000	2,580,000	2,580,000
Adm./gen. overheads	991,714	1,137,247	1,185,264	1,180,922	1,208,592	1,323,590
Insurance & local taxes	1,709,520	2,018,040	2,284,800	2,260,680	2,414,400	3,053,280
Maintenance	2,564,280	3,027,060	3,427,200	3,391,020	3,621,600	4,579,920
Sub-total	7,545,514	8,762,347	9,477,264	9,412,622	9,824,592	11,536,790
Variable Costs (Availability - 95%)						
Feedstock & fuel	70,965,387	73,281,851	77,393,826	73,899,460	70,804,450	77,962,676
Raw water (make-up)	99,365	101,861	128,658	101,362	99,365	70,071
Chemicals & catalysts	420,000	420,000	505,000	420,000	420,000	420,000
Sub-total	71,484,752	73,803,712	78,027,484	74,420,822	71,323,814	78,452,748
Total Fixed & Variable Cost	79,030,265	82,566,059	87,504,748	83,833,444	81,148,406	89,989,538
Other Revenues						
Electricity Export / Import	-6,603,008	-993,314	-1,026,602	712,363	-189,076	-283,614
Other Cost						
CO2 Transport & Storage	-	3,877,737	4,908,973	3,791,720	3,569,042	6,661,077
Annual O&M Cost	**72,427,258**	**85,450,483**	**91,387,119**	**88,337,527**	**84,528,373**	**96,367,002**

Levelised Cost of Hydrogen and CO_2 Avoidance Cost

The levelised costs of hydrogen (LCOH) and CO_2 avoidance cost (CAC) are shown in Table 5 and its breakdown are shown in Figure 8.

Table 5. Summary of results: LCOH and CAC

Case	**LCOH Euro Cent/Nm^3**	**CO_2 Avoidance Cost €/t**
Base	11.4	-
Case 1A	13.5	47.1
Case 1B	14.6	62.0
Case 2A	14.2	66.3
Case 2B	14.0	59.5
Case 3	16.5	69.8

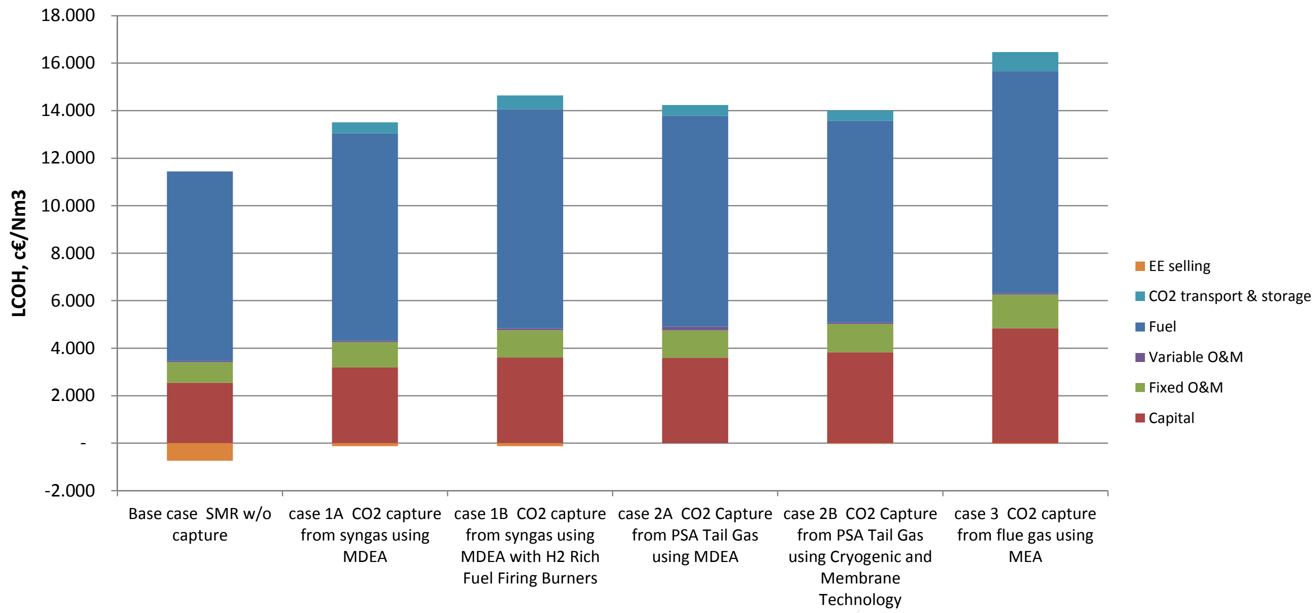

Figure 8: Levelised Cost of Hydrogen

Sensitivity Analysis

Figure 9 presents the sensitivity of the CO_2 avoidance cost to the price of natural gas. It could be demonstrated that with a lower natural gas price, Case 1A has the lowest CAC. Whilst, a higher natural price could favour Case 2B.

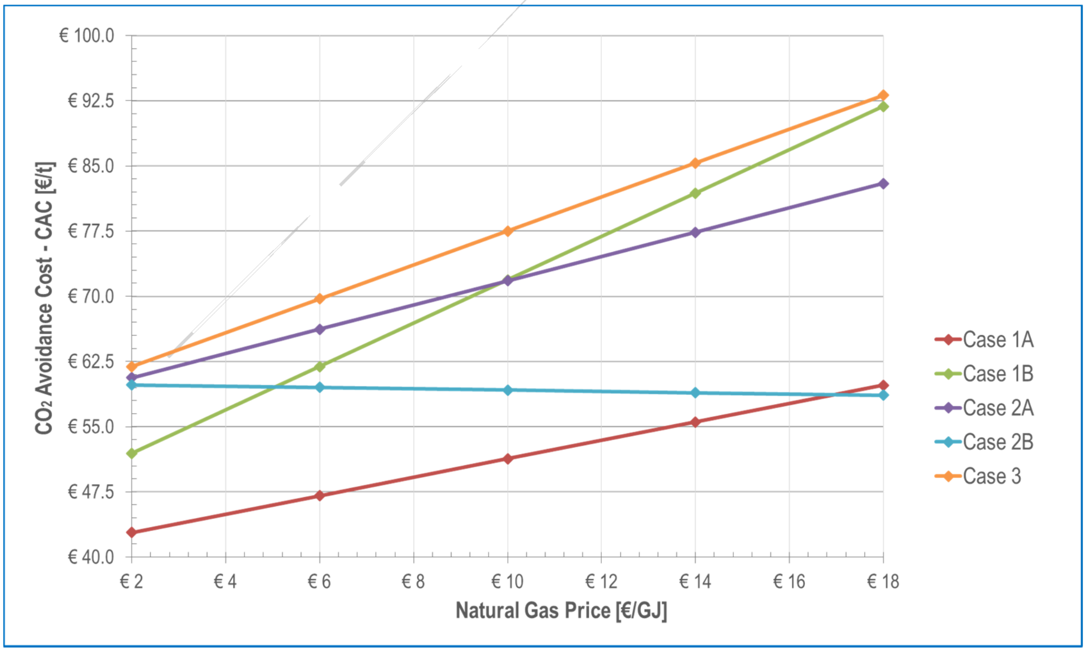

Figure 9: Sensitivity of CAC to the price of natural gas

Figure 10 presents the sensitivity of the CO_2 avoidance cost to the selling/buying price of the electricity. It could be illustrated that the increasing electricity price has a larger impact to Case 2A than in any other cases (i.e. violet line with steeper slope). This is mainly due to the requirements of the H_2 plant to import electricity from the grid to cover the additional demand of the CO_2 capture facilities.

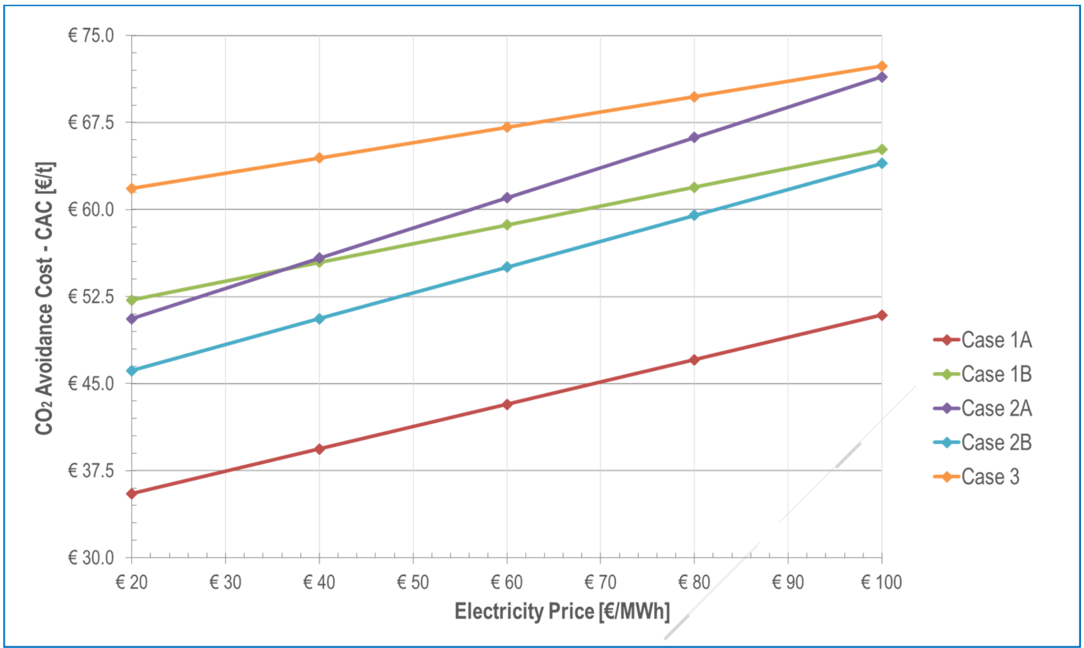

Figure 10: Sensitivity of CAC to the selling/buying price of electricity

Figure 11 presents the sensitivity of the cost of CO_2 emissions (i.e. CO_2 tax) to the LCOH. It can be seen that it would need a cost of € 75-100/t on CO_2 emissions to make the higher capture rate option (Case 3) more attractive than the partial CO_2 capture rate (as compared to Case 1A to Case 2B).

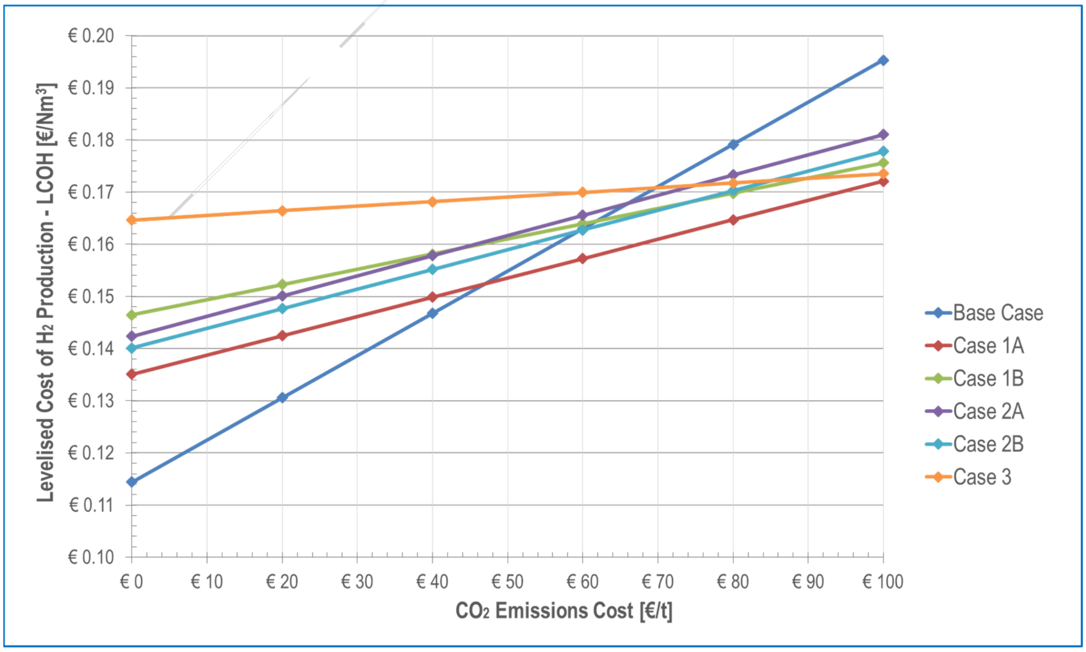

Figure 11: Sensitivity of LCOH to the CO_2 Emissions Cost (i.e. CO_2 Tax)

Conclusions

- In a SMR based H_2 plant, CO_2 could be captured from three areas of the plant: (1.) shifted syngas, (2.) PSA tail gas, or (3.) SMR flue gas.

- The study has presented a detailed baseline information on the performance and cost of deploying CO_2 capture and storage in a SMR based H_2 plant using natural gas as a feedstock / fuel and operating as a merchant plant (i.e. a standalone facility without any integration to other industrial processes on an industrial complex).

- Case 1A presents the current state-of-the-art technology for a SMR based H_2 plant with CCS. In this case, capturing CO_2 from the shifted syngas using MDEA could increase the natural gas consumption by 0.46 MJ/Nm^3 H_2 compared to the Base Case. This results in an avoided CO_2 of 54%. This increases the LCOH by 2.1 c€/Nm^3 (at 13.5 c€/Nm^3) as compared to the Base Case.

- Case 1B presents a scenario whereby H_2 rich fuel could be used as supplementary fuel (instead of natural gas). Compared to Case 1A, the CO_2 avoided has been increased from 54% to 64%. This case would require the scaling up of the capacity of the SMR and associated equipment by 27% to produce enough syngas to maintain the fix production rate of 100,000 Nm^3/h H_2 (as part of the sweet syngas is used as supplementary fuel to the burners of the SMR). This results in an increase of the natural gas consumption by 1.3 MJ/Nm^3 H_2 as compared to the Base Case. Consequently, this increases the LCOH by 3.2 c€/Nm^3 (at 14.6 c€/Nm^3).

- Case 2A presents the second conventional way of capturing CO_2 from an SMR based H_2 plant. This involves the capture of CO_2 from the PSA tail gas using chemical absorption (using MDEA). This case can achieve a CO_2 avoidance of 52%. The plant's natural gas consumption increases to 14.8 MJ/Nm^3 (this is an increase of 0.59 MJ/Nm^3 as compared to Base Case). The additional electricity consumption also include the re-compression of the tail gas to 10 bar; thus requiring to buy electricity from the grid of around 1.1MWe to cover the deficit. Consequently, this increases the LCOH by 2.8 c€/Nm^3 (at 14.2 c€/Nm^3) as compared to the Base Case.

- Case 2B presents a technology that could be classified as high CAPEX / low OPEX plant – which could be suitable for regions of the world where the natural gas price is very high. In this case, the CO_2 is captured from the PSA tail using low temperature and membrane separation technology. It could be seen that the natural gas consumptions could be slightly reduced by 0.03 MJ/Nm^3 as compared to the Base Case, slightly off-setting the high CAPEX required. This case results in an increase in an increase to the LCOH of 2.6 c€/Nm^3 (at 14.0 c€/Nm^3) as compared to the Base Case.

- Case 3 presents one of the options to capture around 90% CO_2 emitted by the SMR (high capture rate scenario). In this case, CO_2 is captured from the SMR flue gas. In this case, the natural gas consumption of the SMR based H_2 plant increases by 1.6 MJ/Nm^3 H_2 as compared to the Base Case which results in an increase of the LCOH by 5.2 c€/Nm^3 (at 16.5 c€/Nm^3)

Recommendations

Among the different energy intensive industries evaluated, the SMR based H_2 production is considered as a low hanging fruit for early deployment of CCS. This could be demonstrated by the number of large scale demonstration and pilot projects that are operational or under construction. This is also relevant in other energy intensive industries such as production of ammonia/urea, methanol, DRI and many others. IEAGHG should continue to monitor the development of deploying CCS in this industrial sector.

Additionally, it is also recommended to summarise IEAGHG's studies on costs and emissions of coal and natural gas-based hydrogen production plants with CCS to provide a good overview that could bring together information gathered in this area to feed into new projects such as future decarbonisation strategy for space heating or transport fuel.

Furthermore, this study only covers case scenarios where data of the performance and cost are available to the contractor. This has not covered other technologies that would allow further improvement in efficiency or reduction of cost of capturing CO_2 from the hydrogen plant. It is highly recommended to pursue the evaluation of other cases – which could include but not limited to:

- The evaluation of other reforming configuration – especially very large scale H2 production will be considered. This could include (a.) SMR in parallel or series with gas heated reformer or (b.) use of autothermal reformer in standalone configuration or in tandem with the SMR.

- The importance of evaluating the use of low temperature or medium temperature shift to achieve deeper reduction of CO_2 emission for the Base Case should be also considered in the scope of future studies. This study should cover the optimisation of the natural gas consumption with respect to its CO_2 reduction potential and the amount of export electricity to the grid.

- The use of advance solvent (i.e. second and third generation chemical absorption technologies) to evaluate the potential improvement in efficiency and cost.

- The use of other novel adsorption technology (i.e. PSA or VPSA, membrane, etc…) to capture CO_2 from the shifted syngas or PSA's tail gas.

- Specifically, future study could also evaluate the use of split flow configuration with MDEA solvent for Cases 1A, 1B and 2A. It is essential to identify the trade-off between improving efficiency and expected higher capital expenditure when these configuration are employed.

- It is also important to establish the baseline information for capturing CO_2 from shifted syngas using physical solvent. This should be relevant to any H_2 plants where higher delivery pressure of the H_2 product is necessary.

CLIENT	:	IEA Greenhouse Gas R&D Programme (IEAGHG)
PROJECT NAME	:	Techno-Economic Evaluation of H_2 Production with CO_2 Capture
DOCUMENT NAME	:	Techno-Economic Evaluation of Standalone (Merchant) H_2 Plant
FWI CONTRACT	:	1BD0840A

ISSUED BY	:	G. AZZARO / N. FERRARI
CHECKED BY	:	G. COLLODI
APPROVED BY	:	G. COLLODI

DATE	REVISED PAGES	ISSUED BY	CHECKED BY	APPROVED BY

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List of Abbreviations

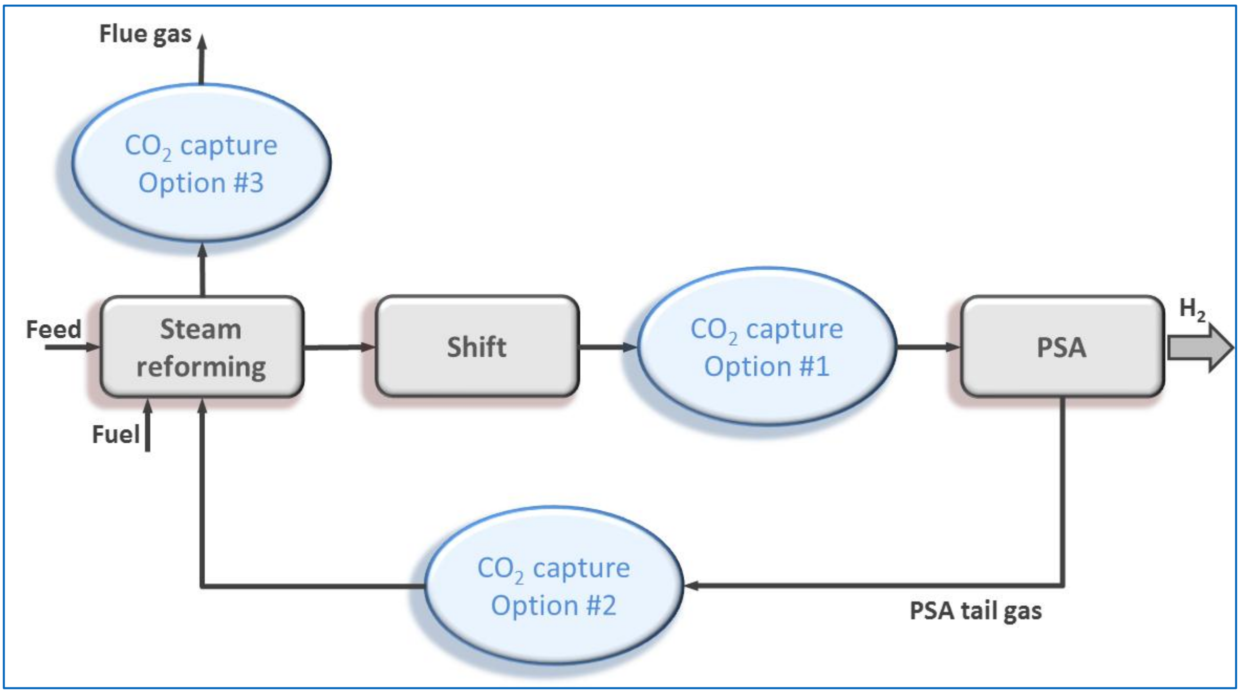
AACE	Association for Advancement of Cost Engineering
ACTL	Alberta Carbon Trunk Line
ASTM	American Society for Testing and Materials
ASU	air separation unit
ATR	autothermal reformer
B.L.	battery limit
BFD	block flow diagram
BFW	boiler feed water
BHP	boiler horsepower
BoP	balance of plant
CAC	CO_2 avoidance cost
CCS	CO_2 capture and storage
CCU	CO_2 capture and utilisation
CWR	cooling water return
CWS	cooling water system
DRI	direct iron reduction
EBITDA	earnings before interest, taxes, depreciation and amortisation
H&MB	heat and mass balance
HC	hydrocarbon
HRU	hydrogen recovery unit
HTS	high temperature shift
HYCO	hydrogen and carbon monoxide (gas mixture)
LCOE	levelised cost of electricity
LCOH	levelised cost of hydrogen
LCOMeOH	levelised cost of methanol
LCOU	levelised cost of urea
LHV	low heating value
LTS	low temperature shift
MAC	main air compressor
MDEA	mono-diethanol amine
MEA	mono-ethanol amine
MTS	medium temperature shift
MUG	make-up gas
NG	natural gas
NGCC	natural gas combined cycle
POX	partial oxidation
PSA	pressure swing adsorption
SMR	steam methane reformer
TCR	total capital requirement
TIC	total installed cost
TPC	total plant cost
USC-PC	ultra-supercritical pulverised coal fired boiler
VSA	vacuum swing adsorption
WHB	waste heat boiler
WWT	waste water treatment plant

1. Introduction

The objective of this document is to define and evaluate the techno-economics of deploying CO_2 capture in a standalone (merchant) SMR based Hydrogen Plant using Natural Gas as feedstock/fuel.

In order to evaluate performance and cost of the Hydrogen Plant with and without CO_2 capture, a base case is defined and used as reference plant for comparing the different CO_2 removal options. The reference plant does not include any CO_2 capture system and its characteristics are defined according to the information provided in the Annex I - Reference Document (Task 2) of this study.

The figure below illustrates the different possibilities where the CO_2 capture systems could be installed within the SMR based Hydrogen Plant.



The different CO_2 capture options investigated in this document comprise the following technologies:

- Case 1A: CO_2 Capture from Shifted Syngas using MDEA
- Case 1B: CO_2 Capture from Shifted Syngas using MDEA with H_2-Rich Fuel Firing Burners
- Case 2A: CO_2 Capture from PSA Tail Gas using MDEA
- Case 2B: CO_2 Capture from PSA Tail Gas using Low Temperature (Cryogenic) and Membrane Separation Technologies
- Case 3: CO_2 Capture from Flue Gas using MEA

The CO_2 capture technologies evaluated in this document are selected in line with the most of the relevant technologies that could be deployed in an SMR based Hydrogen Plants today.

The data relevant to the performance and cost of the Base Case and the CO_2 Capture Cases are used in evaluating the levelised cost of H_2 production or LCOH (taking into consideration the co-production of electricity) and the CO_2 avoidance cost.

2. Base Case

2.1. Basis of Design

This section should be referred to Annex I - Reference Document (Task 2) - for the general plant design criteria and assumptions used in the development of the Base Case.

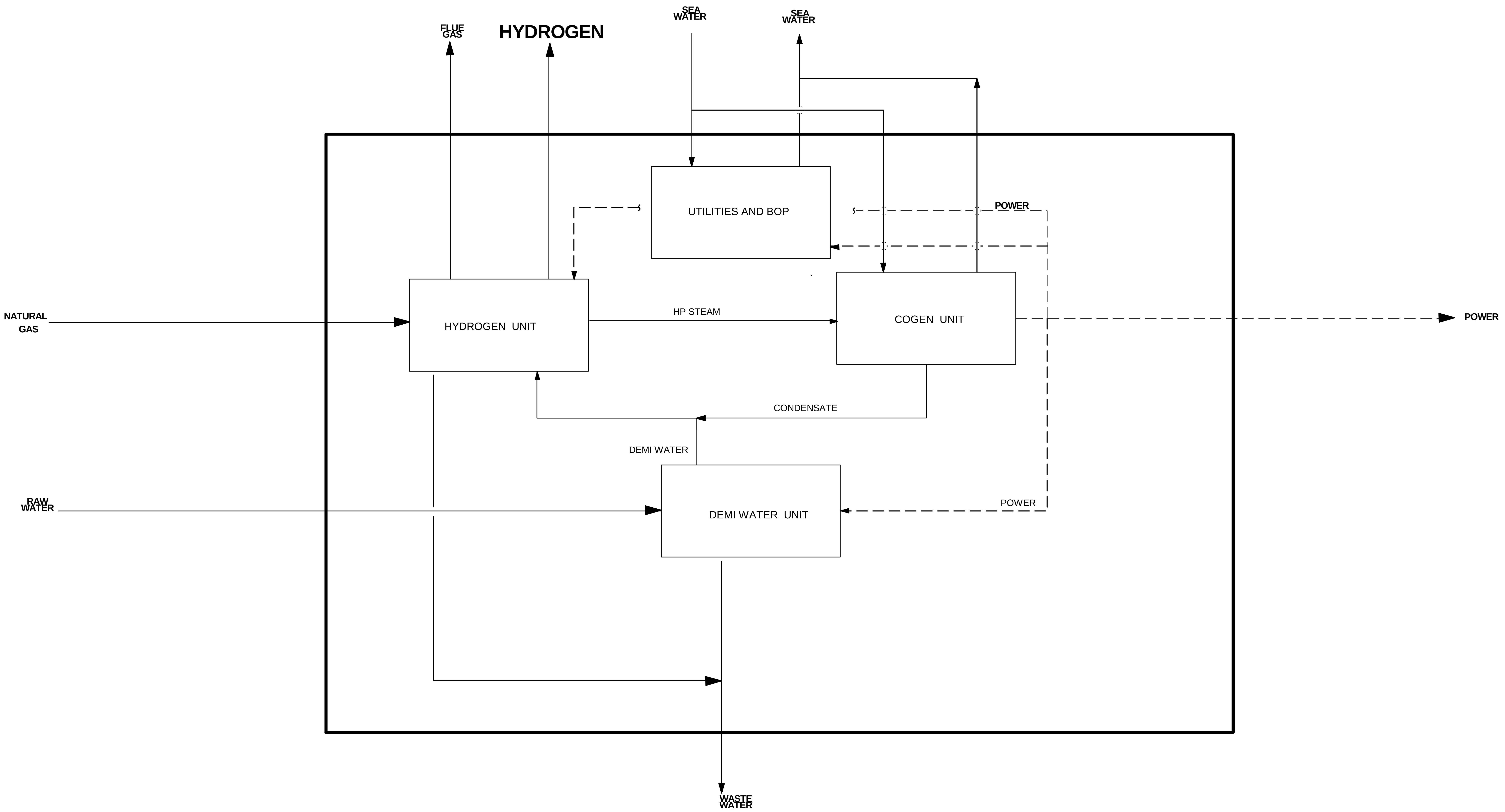
2.2. Units Arrangement

The units included in Base Case (Hydrogen Plant without CCS) are as follows:

- Hydrogen Plant
- Cogen Plant (Power Island)
- Demi-Water Plant
- Utilities and Balance of Plant (BoP), consisting of:
  - Cooling Water System
  - Instrument/Plant Air System
  - Nitrogen Generation Package
  - Flare System
  - Interconnecting (pipelines, electrical distributions, etc…)
  - Drain System
  - Buildings (Control Room, Laboratories, Electrical Sub-Station).

2.3. Overall Block Flow Diagram

The BFD presented in the next page shows the different unit processes and the relevant inlet/outlet streams included in the Hydrogen Plant for the Base Case.



Battery Limits Summary							
	Inlet Streams			Outlet Streams			
	Natural Gas From B.L.	Raw Water	Sea Water	Hydrogen	Flue gas to ATM	Power	Waste Water
	Kg/h	Kg/h	m3/h	Kg/h	Kg/h	kW	kg/h
Flow rate	30563	59700	3435	8994	257698	9918	15500

Rev	Date	Comment	By	App.	
1	15/06/2015		GA	GC	UNIT: Overall Block Flow Diagram
					Case: Base case — Sheet 01of 01

2.4. Process Description

This section includes the description of the key processes included in the Hydrogen Plant without CCS (Base Case).

2.4.1. Hydrogen Plant

The processes described in this section makes reference to the Process Flow Diagram of the SMR based hydrogen plant presented in Section 2.5.

Natural gas from B.L. is initially pre-heated to 135°C in the Feed Pre-heater (heated by the cooled shifted syngas leaving the BFW pre-heater in the syngas cooling section) and then laminated to 3.70 MPa. Part of the natural gas (as feedstock) is mixed with a slipstream of hydrogen (recycled) produced from the PSA unit and sent to the feedstock pre-treatment section, and the rest of the natural gas (as supplementary fuel) is sent to the steam reformer burners.

The pre-heated feedstock is further heated up to 370°C in the Feed Pre-Heater Coil situated in the convective section of the steam reformer.

The pre-heated feedstock is then sent to the desulphurisation unit (sulphur adsorber bed) to remove any H_2S present in the feed. It should be noted that the removal of any sulphur components is required to protect the downstream catalysts which could be poisoned by these impurities.

The treated (purified) feed gas is then mixed with a high pressure superheated steam in order to maintain a fixed overall steam to carbon ratio of around 2.7-2.8 (molar basis). The amount of steam added to the feed gas is regulated by a flow-ratio control. The superheated steam is produced from the cooling of the flue gas and syngas as described in the later part of this section.

The mixture of steam and feed gas is further heated in the Pre-Reformer Feed Pre-heater Coil located in the convective section of the steam reformer before being fed into the Pre-Reformer. The inlet temperature of feed gas going into the Pre-reformer is regulated by injecting BFW into the superheated steam in the Pre-reformer Steam De-superheater (generally situated up-stream of the Pre-Reformer Feed Pre-heater Coil).

The Pre-Reformer (an adiabatic reactor) is mainly responsible for converting any heavy hydrocarbons in the feed to CH_4 and other co-products (i.e. CO_2, CO and H_2). Primarily, it takes over part of the overall reforming duty of the steam methane reformer (SMR) – i.e. by transferring some of the reformer duty from the SMR to the Pre-Reformer, the efficiency of the process is increased. The residual C_2+ in the product gas of the Pre-Reformer is regulated not to exceed 500 ppmv (max).

The product gas of the Pre-Reformer is then mixed with a smaller second stream of high pressure superheated steam to adjust (fine tune) the steam to carbon ratio. The amount of steam added is also regulated by the flow ratio control.

The product gas from the Pre-Reformer is then further heated to it required operating temperature in the Reformer Pre-heater Coil which is also located in the convective section of the steam reformer before being fed into the main reformer tubes situated in the radiant section of the steam reformer furnace. The inlet temperature of the Reformer's feed gas is also controlled by injecting BFW in the Reformer Process Steam De-superheater (generally situated up-stream of the Reformer Pre-heat Coil).

In the radiant section of the Steam Reformer, the pre-heated mixture of feed gas and steam that is fed into the top of the catalyst filled tubes where steam reforming reaction occurs to produce an equilibrium mixture of H_2, CO, CO_2, CH_4 and H_2O. Generally, the residual CH4 in the product gas (un-shifted syngas) is in the range of 3.3 to 4% - dry molar basis. Also, it should be noted that the total amount of process steam added into the feed gas is always in excess of the stoichiometric requirement, in order to prevent any carbon formation on the catalyst.

In this study, the process design of the steam methane reformer is based on the Foster Wheeler Terrace Wall ™ reformer.

This features a radiant section consisting of a firebox(es) containing a single row of catalyst filled tubes. The tubes are heated by several burners in a terrace arrangement (i.e. 2 rows of burners in 2 levels firing upward parallel to the terraced wall). The hot flue gas leaving the furnace is exhausted into the convective section situated on top of the furnace.

The convective section has several coils which recovers the heat from the flue gas leaving the radiant section. This is responsible for heating various process gas and steam production. This consists of the following heat exchanger coils:

- Reformer Pre-heater Coil
- Pre-Reformer Feed Pre-heater Coil
- Steam Superheater Coil
- Feed Pre-heater Coil
- Steam Generation Coil

The furnace exit gas temperature is generally around 800 to 900oC. The steam methane reformer is typically designed to recover as much heat from the flue gas in the convective section whilst avoiding any dew point problems.

The overall heat balance of the steam reforming reactions is strongly endothermic, so heat has to be supplied to achieve the required conversion. This is mainly supplied by the combustion of the tail gas (coming from the PSA unit) and natural gas (as supplementary fuel – coming from the B.L.).

The combustion air is normally pre-heated by flue gas (leaving the convective section) in the gas-gas heat exchanger.

The syngas (un-shifted) or the product gas leaving the steam reformer tubes (normally at around 900-950°C) is fed into the Reformer Waste Heat Boiler (based on natural circulation steam generator) where it is cooled to 320°C. The recovered heat is used to generate high pressure saturated steam and this is sent to the superheater coil situated in the convective section of the steam reformer.

The cooled product gas leaving the steam reformer effluent is then fed into the Shift Converter, where the excess steam converts most of the CO to CO_2 and H_2 over a bed of catalyst.

In this study, the High Temperature Shift Reactor has been selected due to its robust performances and simple start-up and shutdown requirements. Residual CO from a HT-Shift Reactor is typically within the range of 2.5 to 3.5% (dry molar basis).

The shifted syngas from the Shift Reactor is cooled in a train of heat exchangers which includes:

- Shift Converter Waste Heat Boiler
- BFW Pre-heater
- Feed Pre-heater
- Condensate Pre-heater

The cooled shifted syngas (or Raw H_2) is then further cooled in the Raw H_2 air cooler and Demi-water Pre-heater before being fed into a Process Condensate Separator where the condensed water are separated out from the shifted syngas or Raw H_2.

The Raw H_2 is fed into the PSA where the impurities are removed. This involves a cyclic adsorption process comprising of multiple adsorption beds (typically around 6 to 7 beds per train). In this beds, larger molecules (i.e. CH_4, CO_2, CO, etc…) or impurities are adsorbed to produce the pure H_2 product (with purity of >99.9+%). Typically, 85 to 90% of the H_2 in the PSA feed gas are recovered. This is sent to the B.L. and sold to the market; whilst a slipstream of this pure H_2 is re-compressed in the Hydrogen Recycle Compressor and sent back to front end of the Hydrogen Plant (i.e. mixed with the natural gas feedstock after the Feed Pre-heater).

The regeneration of the PSA adsorbent bed involves the desorption of the impurities and some residual H_2 to produce the PSA tail gas by depressurisation. This is sent to the SMR burners as the main fuel.

The Hydrogen Plant produces High Pressure Saturated Steam at 4.23 MPa by recovering heat from the syngas or flue gas via the (a.) Reformer Waste Heat Boiler, (b.) Shift Converter Waste Heat Recovery and (c.) Convective Section Steam Generator. Around 75% of the saturated steam are generated from the Reformer Waste Heat Boiler.

The saturated steam is sent to the Steam Superheater Coil to produced high pressure superheated steam at 4.23 MPa and 395^oC. Part of this steam is used by the pre-reformer and the main reformer; whilst the excess steam produced are exported to the COGEN Plant. A small portion of the export steam (< 1%) is delaminated and sent to the deaerator as supplementary LP steam for stripping.

The BFW required to generate the steam are derived from the (a.) process condensate collected from the Process Condensate Separator, (b.) condensate collected from the condenser of the steam turbine at the COGEN plant, and (c.) make-up BFW.

The make-up BFW are obtained from the demi-water plant. The required amount of demineralised water (as make-up BFW) are combined with the condensate collected from steam turbine. These are pre-heated in the Demi-Water Pre-Heater before being sent to the deaerator for the required chemical dosing and treatment. Similarly, the process condensate (condensed water collected from Process Condensate Separator) are pre-heated in the Condensate Pre-heater before being sent to the dearetor.

All the water collected contain some amount of impurities (i.e. dissolved CO_2, O_2, and other trace elements) which could be detrimental to the operation of the boiler and steam generators. These impurities are removed from the de-aerator. Impurities such as CO_2 and other trace elements are stripped using LP steam in the Deaerator.

LP steam produced in the Blowdown Drum is used as stripping medium in the Deaerator. This is supplemented with the LP steam delaminated from the HP steam (taken from the export steam to the Cogen Plant). The Deaerator vent, consisting mainly of steam, is discharged to the atmosphere.

Additionally, chemicals for pH control and oxygen scavenger are injected into the deaerated BFW before being pumped (via BFW pumps – one working and one spare) to the BFW Pre-heater and then sent to the Steam Drum.

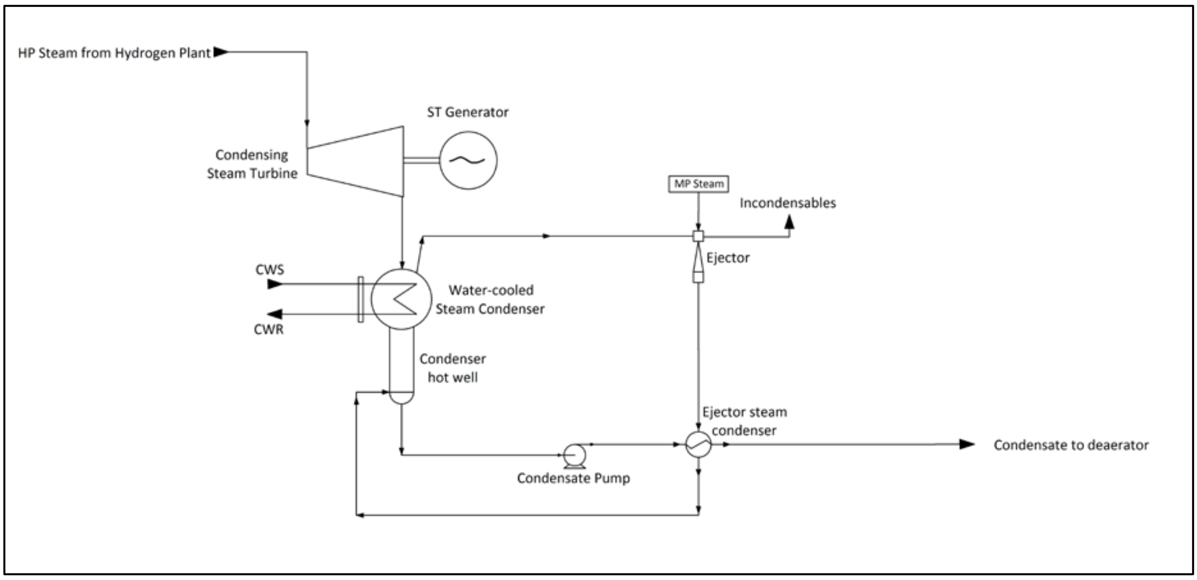
From the Steam Drum, the BFW is sent to the Reformer Waste Heat Boiler and to the Shift Converter Waste Heat Boiler by gravity, and sent to the convective section Steam Generator Coil via the BFW Circulating Pumps (one working and one spare). In the steam drum, it is expected that the BFW will be treated with phosphate chemicals to minimise any corrosion and fouling.

Also, as part of normal operation, the continuous and intermittent blowdown from the Steam Drum is expected. The blowdown steam is flashed into the Blowdown Drum where the LP steam is generated. This is sent to Deaerator for stripping out impurities in the BFW and condensates.

Hot condensate coming from the Blowdown Drum is cooled in Blowdown Cooler and is sent to sewer. This is regulated by the level control in the Blowdown Drum.

2.4.2. Cogen Plant (Power Island)

The Cogen Plant consists of one condensing type steam turbine driven by the superheated steam exported by the Hydrogen Plant. The electricity generated by the Cogen plant supplies the electricity required by the Hydrogen Plant and other utilities. Typically, surplus electricity could be generated and this is exported to the local grid. Condensate collected from the steam turbine are sent back to the Hydrogen Plant's BFW system. The schematic block flow diagram is shown in the figure below.



2.4.3. *Demi-Water Plant and Cooling Water System*

The Demi-Water required for the steam production is derived from the raw water treated in a Reverse-Osmosis system and electro-deionization system. The plant includes one raw water tank and one Demi-Water tank and relevant pumps, plus a potable water package and storage.

The treated Demi-Water is also used as cooling water in the closed circuit system (secondary system) used in process and machinery cooling. This cooling water is indirectly cooled by sea water using plate heat exchangers.

Sea water in once through system (primary system) is used directly by the steam turbine condenser.

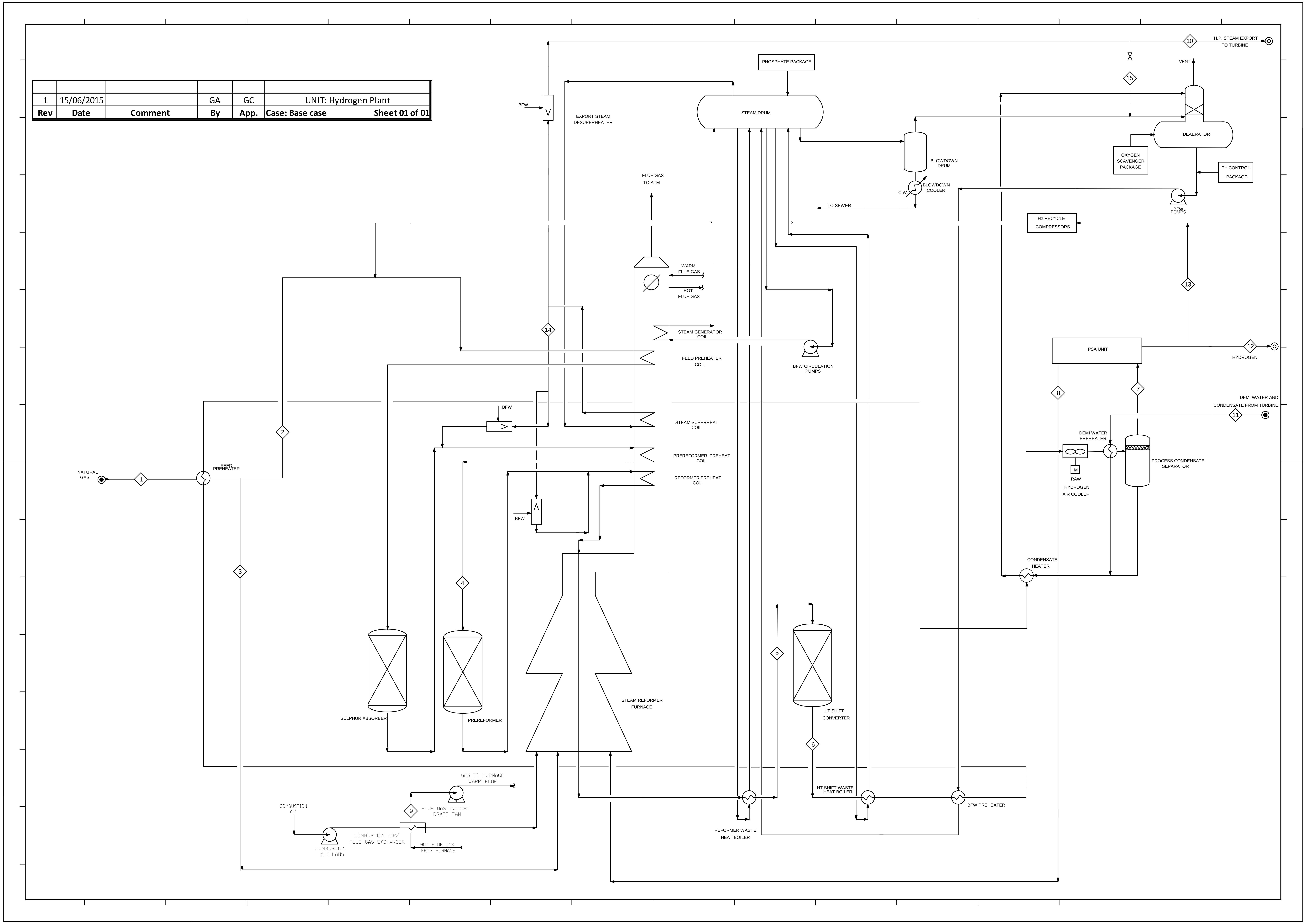
2.4.4. *Balance of Plant (BoP)*

The operation of the whole unit is supported by additional utilities and facilities such as:

- Instrument/Plant Air System
- Nitrogen System
- Flare System
- Drain System
- Interconnecting
- Buildings (Control Room, Electrical Sub-station, Laboratories).

2.5. Process Flow Diagram (Hydrogen Plant)

The PFD enclosed shows the different sections included in the Hydrogen Plant. These processes are described in Section 2.4.


1
15/06/2015
GA
GC
UNIT: Hydrogen Plant
Rev
Date
Comment
By
App.
Case: Base case
Sheet 01 of 01
H.P. STEAM EXPORT
TO TURBINE
PHOSPHATE PACKAGE
VENT
BFW
EXPORT STEAM
DESUPERHEATER
STEAM DRUM
DEAERATOR
OXYGEN
SCAVENGER
PACKAGE
PH CONTROL
PACKAGE
BLOWDOWN
DRUM
BLOWDOWN
COOLER
C.W.
BFW
PUMPS
TO SEWER
FLUE GAS
TO ATM
H2 RECYCLE
COMPRESSORS
WARM
FLUE GAS
HOT
FLUE GAS
STEAM GENERATOR
COIL
FEED PREHEATER
COIL
BFW CIRCULATION
PUMPS
PSA UNIT
HYDROGEN
DEMI WATER AND
CONDENSATE FROM TURBINE
STEAM SUPERHEAT
COIL
PREREFORMER PREHEAT
COIL
REFORMER PREHEAT
COIL
DEMI WATER
PREHEATER
RAW
HYDROGEN
AIR COOLER
M
PROCESS CONDENSATE
SEPARATOR
NATURAL
GAS
FEED
PREHEATER
CONDENSATE
HEATER
SULPHUR ABSORBER
PREREFORMER
STEAM REFORMER
FURNACE
HT SHIFT
CONVERTER
HT SHIFT WASTE
HEAT BOILER
BFW PREHEATER
REFORMER WASTE
HEAT BOILER
GAS TO FURNACE
WARM FLUE
FLUE GAS INDUCED
DRAFT FAN
COMBUSTION
AIR
COMBUSTION AIR/
FLUE GAS EXCHANGER
COMBUSTION
AIR FANS
HOT FLUE GAS
FROM FURNACE
1
2
3
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11
12
13
14
15

2.6. Heat and Mass Balance

The Heat and Mass Balances reported in this section makes reference to the Process Flow Diagram presented in Section 2.5.

FOSTER WHEELER		HEAT AND MATERIAL BALANCE Base case			
CLIENT:	IEA GHG	**REV**	**DATE**	**BY**	**CHKD**	**APP**
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		1	2	3	4	5	6	7	8	9	10	11	12
Description		Natural Gas From B.L.	Natural Gas feedstock to Hydrogen Plant	Natural Gas fuel to burners	Purified Feedstock to Pre-reformer	HTS Reactor Inlet	HTS Reactor Outlet	PSA inlet	PSA Tail gas	Flue gas to ATM	HP Steam export	Demi Water (make up) and steam turbine condensate	Hydrogen to B.L
Temperature	*°C*	9	128	121	500	320	412	35	28	136	395	15	40
Pressure	*MPa*	7.00	3.71	0.50	3.39	2.80	2.77	2.58	0.13	0.02	4.23	0.60	2.50
Molar Flow	*kmol/h*	1696.6	1455.8	240.4	5514.0	8370.3	8370.3	6596.9	2106.3	8659.4	2556.0	5095.7	4461.5
Mass Flow	*kg/h*	30563	26231	4332	98874	101667	101667	69711	60658	257698	46053	91800	8994
Composition													
CO_2	*mol/mol*	0.0200	0.0200	0.0200	0.0053	0.0492	0.1283	0.1627	0.5095	0.2123	0.0000	0.0000	0.0000
CO	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.1156	0.0366	0.0464	0.1454	(2)	0.0000	0.0000	0.0000
Hydrogen	*mol/mol*	0.0000	0.0000	0.0000	0.0053	0.5171	0.5961	0.7563	0.2369	0.0000	0.0000	0.0000	0.9999+
Nitrogen	*mol/mol*	0.0089	0.0089	0.0089	0.0023	0.0015	0.0015	0.0020	0.0062	0.6083	0.0000	0.0000	0.0000
Oxygen	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0102	0.0000	0.0000	0.0000
Methane	*mol/mol*	0.8900	0.8900	0.8900	0.2350	0.0238	0.0238	0.0302	0.0945	0.0000	0.0000	0.0000	0.0000
Ethane	*mol/mol*	0.0700	0.0700	0.0700	0.0185	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	*mol/mol*	0.0100	0.0100	0.0100	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	*mol/mol*	0.0010	0.0010	0.0010	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	*mol/mol*	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	*mol/mol*	0.0000	0.0000	0.0000	0.7307	0.2927	0.2137	0.0024	0.0076	0.1692	1.0000	1.0000	0.0000
Contaminants:													
H_2S	*ppm v*	(1)											
NOx	*mg/Nm3*									120 max			

Notes:

(1) For feedstock purification section design purposes 5 ppmv of H_2S have been assumed in NG to Hydrogen Plant

(2) 30 mg/Nm3 max

FOSTER WHEELER

HEAT AND MATERIAL BALANCE
Base case

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG					
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		13	14	15									
Description		H2 Recycle	HP Steam to process	LP Steam To Deareator									
Temperature	°C	40	400	177									
Pressure	MPa	2.51	4.29	0.44									
Molar Flow	kmol/h	29.1	5290.1	30.0									
Mass Flow	kg/h	59	95301	540									
Composition													
CO2	mol/mol	0.0000	0.0000	0.0000									
CO	mol/mol	0.0000	0.0000	0.0000									
Hydrogen	mol/mol	0.9999+	0.0000	0.0000									
Nitrogen	mol/mol	0.0000	0.0000	0.0000									
Oxygen	mol/mol	0.0000	0.0000	0.0000									
Methane	mol/mol	0.0000	0.0000	0.0000									
Ethane	mol/mol	0.0000	0.0000	0.0000									
Propane	mol/mol	0.0000	0.0000	0.0000									
n-Butane	mol/mol	0.0000	0.0000	0.0000									
n-Pentane	mol/mol	0.0000	0.0000	0.0000									
H2O	mol/mol	0.0000	1.0000	1.0000									
Contaminants:													
H2S	ppm v												
NOx	mg/Nm3												

Notes:

2.7. Plant Performance Data

The table below summarizes the energy performance and the CO_2 emissions relevant to the hydrogen production for the Base Case.

Plant Performance Data Base Case		
INLET STREAMS		
Natural Gas (as Feedstock)	t/h	26.231
Natural Gas (as Fuel)	t/h	4.332
Natural Gas (Total Consumption)	t/h	30.563
Natural Gas LHV	MJ/kg	46.50
Total Energy Input	MW	394.77
OUTLET STREAMS		
Hydrogen Product to BL	t/h	8.994
	Nm^3/h	100,000
Hydrogen LHV	MJ/kg	119.96
Total Energy in the Product	MW	299.70
POWER BALANCE		
Gross Power Output from the COGEN Plant	MWe	11.500
Hydrogen Plant Power Consumption	MWe	-1.216
COGEN Plant + Utilities + BoP Consumption	MWe	-0.366
CO2 Capture Plant	MWe	NA
CO2 Compression and Dehydration Unit	MWe	NA
Excess Power to the Grid	MWe	9.918
SPECIFIC CONSUMPTIONS		
Natural Gas (as Feedstock)	GJ/1000 Nm^3 H_2	12.197
Natural Gas (as Fuel)	GJ/1000 Nm^3 H_2	2.014
Feed + Fuel	GJ/1000 Nm^3 H_2	14.212
SPECIFIC EMISSIONS		
Specific CO2 Emission	t/1000 Nm^3 H_2	0.8091
Specific CO2 Captured	t/1000 Nm^3 H_2	NA
Overall CO2 Capture Rate (Case Specific)		NA
Overall CO2 Capture Rate (as Compared to Base Case)		NA

2.8. Preliminary Utilities Consumption

This section presents the different utilities consumption (usage) of the Hydrogen Plant, Power Island, and others.

ESTIMATED UTILITY CONSUMPTIONS

CUSTOMER NAME: IEAGHG	**Base case**	REV.	REV. 0						SHEET
PROJECT NAME: TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE		BY	GA						1
FWI CONTRACT: 1BD0840 A		CHKD	CG						OF
LOCATION: THE NETHERLAND		DATE	April 2015						1

	ELECTRIC POWER		STEAM t / h			EFFLUENT	LOSSES	DMW	RAW WATER	COOLING WATER		SEA WATER		FUEL	INSTR. AIR	Nitrogen
	LOAD BHP	kW	LP	MP	HP	t/h	t/h	t/h	t/h	ΔT (°C)	m³/hr	ΔT (°C)	m³/hr	MMKcal/h	Nm^3/h	Nm^3/h
HYDROGEN PLANT		1216	0.00	0.00		-1.71	-44.2 (2)	91.8 (1)	0.00	11	9.70			48.2	100	(250)
					-45.9											
POWER ISLAND		19			45.9							7	3420			
		-11,500						-45.9								
UTILITIES / BoP		347				-13.8			59.7	11	-9.70	7	15	0.5	100	(250)
								-45.9							-200	(-500)
TOTAL		-9,918	0	0	0	-15.5	-44.2	0	59.7	-	0	-	3,435	48.7	0	0

NOTES:

(1) DMW is the sum of DMW plus condensate from turbine

(2) Losses includes water consumed in the reaction and deaerator vent

(3) Water effluent (to be sent to WWT) includes demi plant eluate and steam drum blowdown in the hydrogen plant

2.9. Preliminary Equipment List and Size of the Main Components/Packages

This section presents the preliminary list of equipment and main components/package relevant to the Base Case.

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	**CLIENT:**	IEA GHG	0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						8
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	SIZE ID (mm)	SIZE L / H (mm)	DESIGN PRESSURE (MPa)	DESIGN TEMPERATURE (°C)	MATERIAL	REMARKS		REV.
DRUMS										
	FUEL GAS K.O. DRUM	VERTICAL								
	STEAM DRUM	HORIZONTAL								
	PROCESS CONDENSATE SEPARATOR	VERTICAL								
	BLOWDOWN DRUM	VERTICAL								
	DEAERATOR	Stripping Section: Vertical Storage Section: Horizontal								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	**CLIENT:**	IEA GHG	**0**	April 2015	GA	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	SIZE ID mm	SIZE L / H mm	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
REACTORS										
	SULPHUR ABSORBERS	VERTICAL	2450	3650	4.075	400				
	PRE-REFORMER	VERTICAL	2100	3050	4.075	530				
	SHIFT CONVERTER	VERTICAL	3400	4400	3.080	430				

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS & COILS										
	FEED PRE-HEATER	SHELL & TUBE								
	HTS WASTE HEAT BOILER	SHELL & TUBE								
	BFW PRE-HEATER	SHELL & TUBE								
	CONDENSATE HEATER	SHELL & TUBE								
	DEMIWATER PRE-HEATER	SHELL & TUBE								
	BLOWDOWN COOLER	SHELL & TUBE								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	4
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS & COILS										
	COMBUSTION AIR / FLUE GAS EXCHANGER									
	STEAM GENERATOR COIL	COIL								
	STEAM SUPERHEATER COIL	COIL								
	FEED PREHATER COIL	COIL								
	PRE-REFORMER FEED PREHEATER COIL	COIL								
	REFORMER FEED PREHEATER COIL	COIL								
	REFORMER WASTE HEAT BOILER	SHELL & TUBE								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	**0**	April 2015	GA	GC	GC	5
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	DUTY	SIZE		DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			WIDTH	LENGTH						
		MM Kcal/h	mm	mm	MPa	°C	HEADER/TUBES			
AIR COOLERS										
	RAW HYDROGEN AIR COOLER									
FIRED EQUIPMENT										
	STEAM REFORMER FURNACE	82.63 (**)						(**) Radiant Duty		

FWI -110/45 BASE: EQLIST0_00.XLT PRINTED ON: 24/06/2015

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	6
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						8
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	HEAD	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			m^3/h	m	MPa	kW	CASING/IMPELLER			
PUMPS										
	BFW CIRCULATION PUMPS	Centrifugal								
	BFW FEED PUMPS	Centrifugal						Two pumps electrical motor driven		

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	7
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
COMPRESSORS & BLOWERS										
	RECYCLE HYDROGEN COMPRESSORS PACKAGE	Reciprocating	653	2.505 / 4.001	4.40	16				
	COMBUSTION AIR BLOWERS							Two Blowers: one operating, one spare		
	FLUE GAS BLOWERS									

FWI -110/45 BASE: EQLIST0_00.XLT PRINTED ON: 24/06/2015

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	8
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	BASE CASE						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW Nm³/h	PRESSURE INLET/OUTLET MPa	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
MISCELLANEA										
	STEAM VENT SILENCER									
	REFORMER STEAM DESUPERHEATER									
	PREREFORMER STEAM DESUPERHEATER									
	PHOSPHATE PACKAGE									
	EXPORT STEAM DESUPERHEATER									
	OXYGEN SCAVENGER PACKAGE									
	pH CONTROL PACKAGE									
	PSA UNIT		100661	2.58/2.51 (H2 side)	2.8	80				

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						1
	CASE	BASE CASE						
	UNIT	POWER ISLAND						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
POWER ISLAND										
	STEAM TURBINE AND GENERATOR PACKAGE									
	Including									
	STEAM TURBINE	Condensing type	12 MWe					Including: lube oil system; Cooling system; Hydraulic control system; Seal system Drainage system Gland condenser		
	STEAM TURBINE GENERATOR		15 MVA					Including relevant auxiliaries		
	STEAM TURBINE BYPASS SYSTEM									
	STEAM CONDENSER PACKAGE		24 x 10^6 kcal/h	Condensing pressure: 8 kPa				Including: Condenser hotwell Ejector Start-up Ejector		
	CONDENSATE PUMP	Centrifugal	60 m3/h x 80 m 22 kW					One operating one spare		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						3
	CASE	BASE CASE						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
COOLING WATER SYSTEM										
	SEA WATER PUMPS	Centrifugal	3500 m3/h x 25 m 335 kWe					One operating one spare		
	SEA WATER / CLOSED COOLING WATER EXCHANGER		125 kWth							
	CLOSED COOLING WATER PUMPS							One operating one spare		
	CLOSED COOLING WATER CIRCUIT EXPANSION DRUM									
	CORROSION INHIBITOR PACKAGE									
INSTRUMENT / PLANT AIR SYSTEM										
	AIR COMPRESSOR PACKAGE							including: - Air Compressor - Inter/after coolers - KO Drums (including final KO drum)		
	AIR DRYING PACKAGE	Adsorption bed	200 Nm3/h					including: - Adsorbent Bed (with automatic regenaration system) - Regeneration Electrical Heater - Pre Filters - After Filters		
	IA RECEIVER DRUM	vertical								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	**0**	April 2015	NF	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						3
	CASE	BASE CASE						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
RAW / DEMI WATER SYSTEM										
	RAW WATER TANK	Fixed roof						12 h storage		
	RAW WATER FILTRATION PACKAGE		65 m3/h							
	POTABLE WATER TANK	Fixed roof						12 h storage		
	POTABLE WATER PACKAGE									
	DEMI WATER PLANT FEED PUMPS		65 m3/h x 25 m 7.5 kW					One operating, one spare		
	DEMI WATER PACKAGE UNIT		50 m3/h DW production					Including: - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system		
	DEMIWATER PUMPS		50 m3/h x 50 m 15 kW					One operating, one spare		
	DEMIWATER TANK	Fixed roof						12 h storage		

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						3
	LOCATION	THE NETHERLAND						
	CASE	BASE CASE						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
NITROGEN GENERATION PACKAGE										
	NITROGEN PRODUCTION PACKAGE		500 Nm3/h					Including: - Intake Air Filter - Air Compressor - Air Receiver - Inter/after coolers - KO Drums - Molecular Sieve Water Absorber (Air Dryer) - Chiller Unit - One Expansion Turbine - One Cryogenic Distillation Column - One Main Heat Exchanger		
	LIQUID NITROGEN STORAGE AND VAPORISATION PACKAGE		500 Nm3/h					Including: - Liquid Nitrogen Storage tank - Nitrogen Vaporizer (Air Fin Type) - Nitrogen heater (electrical)		
	GASEOUS NITROGEN BUFFER VESSEL									
FLARE SYSTEM										
	FLARE KO DRUM	Horizontal								
	FLARE PACKAGE		Max relief flowrate 102,000 kg/h; MW:12					Including riser; tip, seal drum		
	FLARE KO DRUM PUMPS	Centrifugal						One operating one spare		
BoP										
	INTERCONNECTING									
	BUILDING (CONTROL ROOM, ELECTRICAL SUBSTATION, LAB)									
	DRAIN SYSTEM									
	FIRE FIGHTING									
	ELECTRICAL SYSTEM							Up to generator terminals		

3. Case 1A

3.1. Basis of Design

This section should be referred to Annex I - Reference Document (Task 2) - for the general plant design criteria and assumptions used in the development of Case 1A (Hydrogen Plant with CO_2 Capture from Syngas using MDEA).

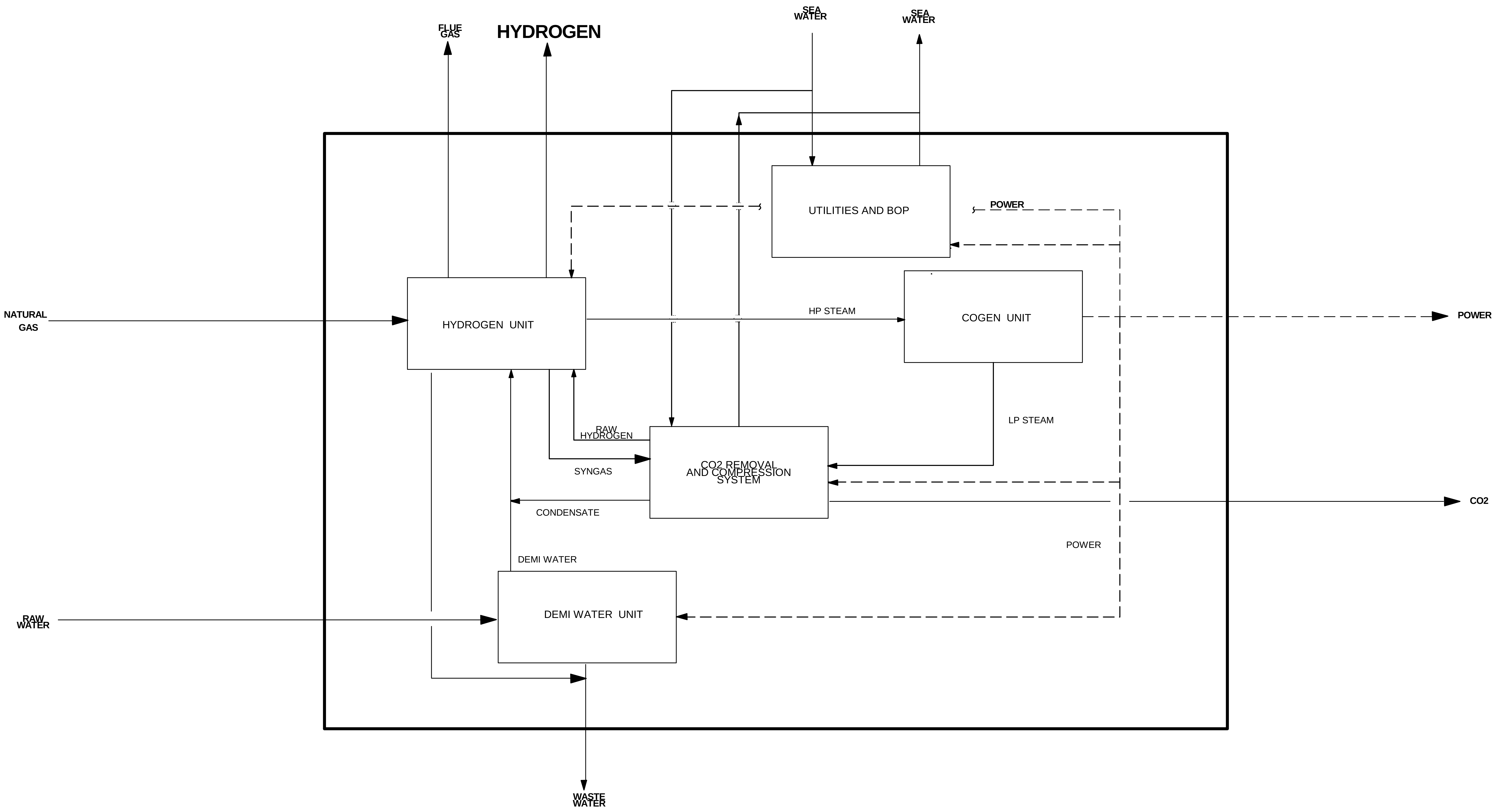
3.2. Units Arrangement

The units included in Case 1A (Hydrogen Plant with CO_2 Capture from Syngas using MDEA) are as follows:

- Hydrogen Plant
- Cogen Plant (Power Island)
- CO_2 Capture System (Capture from Shifted Syngas using MDEA)
- CO_2 Compression and Dehydration Unit
- Demi-Water Plant
- Utilities and Balance of Plant (BoP), consisting of:
  - Cooling Water System
  - Instrument/Plant Air System
  - Nitrogen Generation Package
  - Flare System
  - Interconnecting
  - Drain System
  - Buildings (Control Room, Laboratories, Electrical Sub-Station).

3.3. Overall Block Flow Diagram

The BFD presented in the next page shows the different unit processes and the relevant inlet/outlet streams included in the Hydrogen Plant for Case 1A (with CO_2 Capture from Syngas using MDEA).



Battery Limits Summary								
	Inlet Streams			Outlet Streams				
	Natural Gas From B.L.	Raw Water	Sea Water	Hydrogen	Flue gas to ATM	Power	Captured CO2	Waste Water
	Kg/h	Kg/h	m3/h	Kg/h	Kg/h	kW	kg/h	kg/h
Flow rate	31562	61200	2284	8994	229838	1492	46596	16100

					FOSTER WHEELER
1	15/06/2015		GA	GC	UNIT: Overall Block Flow Diagram
Rev	Date	Comment	By	App.	Case 1A: H2 plant with CO2 Capture from Syngas using MDEA — Sheet 01of 01

3.4. Process Description

This section includes the description of the key processes included in the Hydrogen Plant with CO_2 capture from Syngas using MDEA (Case 1A)

3.4.1. Hydrogen Plant

The processes described in this section makes reference to the Process Flow Diagram of the SMR based hydrogen plant with CO_2 capture from the shifted syngas presented in Sheet 1 of Section 3.5.

The main processes involving the hydrogen production are described in Section 2.4.1.

The Hydrogen Plant of Case 1A (as compared to the Base Case) has a couple of differences and these include:

- Higher Natural Gas consumption (an increase of ~4%$_{wt.}$ as compared to the Base Case) due to the additional supplementary fuel needed to produce the steam required by the CO_2 capture plant.
- The cooled Raw H_2 (or shifted syngas) leaving the Process Condensate Separator is sent to the CO_2 capture plant (instead of being fed into the PSA unit for the Base Case).
- The volume of the gas handled by the PSA unit is smaller (as compared to the Base Case). This is due to the removal of the CO_2 in the capture plant.
- The convective section of the steam reformer which recovers the heat from the flue gas leaving the radiant section includes a steam generation coil and a steam superheater coil with larger duty as compared to the Base Case and an additional BFW pre-heating coil. This is to provide the additional steam generation capacity required to meet the additional steam demand used in the solvent regeneration of the CO_2 capture plant.
- The burners of the SMR will be handling fuel gas with higher LHV (or Wobbe Index) due to the reduced amount CO_2 in the PSA tail gas and higher Natural Gas consumed as supplementary fuel.

3.4.2. CO_2 Capture Plant (MDEA based Chemical Absorption Technology)

The processes described in this section makes reference to the Process Flow Diagram of the CO_2 capture plant presented in Sheet 2 of Section 3.5.

The Raw H_2 (or shifted syngas) leaving the Process Condensate Separator is fed into the Absorber Column where CO_2 is washed out from the syngas by a counter-current flow of lean solvent. The treated Raw H_2 (or washed syngas), now containing around 0.26% CO_2, exits at the top of the absorber column. The rich solvent is collected at the bottom of the column and fed into a Flash Drum (to allow the release and recovery of the co-absorbed hydrocarbons in the rich solvent).

The vapour (flashed gas) released from the Flash Drum is sent to the burners as additional fuel to the steam reformer. Whilst, the rich solvent leaving the bottom of the Flash Drum is sent to the Lean/Rich Heat Exchanger to be heated by the incoming stream of hot lean solvent coming from the Stripper's Reboiler. The hot rich solvent leaving the Lean/Rich Heat Exchanger is then fed into the top of the Stripper Column.

In the Stripper Column, the rich solvent flowing down from the top of the column is stripped of its CO_2 by the vapour generated from the Stripper's Reboiler.

The Stripper's Reboiler generates vapour (mainly steam) by re-boiling the lean solvent coming from the Stripper bottom. The vapour is then sent back to the bottom of the Stripper Column and travels upward to strip the CO_2 from the solvent flowing downward.

The Stripper's Reboiler is heated by the LP steam coming from the Back Pressure Steam Turbine of the Cogen Plant. The condensate recovered from the reboiler is sent back to the Hydrogen Plant's BFW system.

The overhead gas from the Stripper Column is then sent to the Stripper's Condenser where the steam in the overhead gas are condensed, collected and returned as a reflux to the Stripper Column.

The CO_2 rich gas from the Stripper's Condenser is then sent to the CO_2 compression and dehydration unit.

3.4.3. CO_2 Compression and Dehydration

The processes described in this section makes reference to the Process Flow Diagram of the CO_2 compression and dehydration unit presented in Sheet 3 of Section 3.5.

The CO_2 Compression and Dehydration unit includes the Compressor, Knock-out Drums, Inter-Stage Coolers, Dehydration Unit and Liquid CO_2 pump.

The overhead gas (mainly CO_2) leaving the Stripper's Condenser is compressed to a pressure of 8 MPa by a single train seven-stage centrifugal compressor. The CO_2 compressor is an integrally geared and electrically driven machine which is equipped with anti-surge control, vent, inter-stage coolers and knock-out drums in between stages and condensate draining facilities as required.

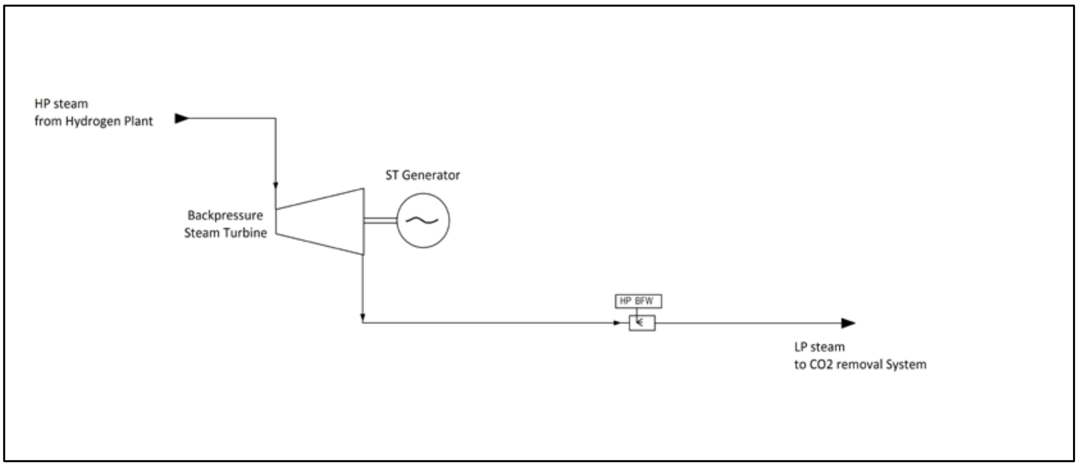
There is one Inter-stage Coolers installed after each compression stage. Seawater is used as cooling medium. The condensed water in the inter-cooler is separated from the gas in the knock-out drum (this is installed after each inter-coolers up to the fourth stage). The gas leaving the fifth inter-stage cooler is then fed into the dehydration unit.

The dehydration unit is based on a molecular sieve / activated alumina adsorbent dryer. The dryer is designed to operate and produce CO_2 product with a dew point temperature of -40°C. The dryer consists of two bed of adsorbents for every train of compressor. During normal operation, one bed is operational and the other bed (saturated with water) is regenerated. The bed are regenerated by the dry product gas (ca. 10% taken from the dried product gas after the dryer). The regeneration gas (now saturated with water) is recycled back after the third stage compression.

The final two compression stages downstream of the dehydration unit increases the CO_2 pressure to 8 MPa. This is design to operate slightly higher than the critical pressure of pure CO_2 (at 7.4 MPa) in order to prevent any risk of 2 phase flow due to the presence of non-condensable gases. After the being cooled, the dried compressed CO_2 (dense phase) is pumped and delivered to the battery limit at a pipeline pressure of 11 MPa.

3.4.4. Cogen Plant (Power Island)

The Cogen Plant consists of a Back Pressure Steam Turbine fed with the high pressure superheated steam exported by the Hydrogen Plant as shown in figure below.



The high pressure steam is expanded in the steam turbine to produce electricity and generates the low pressure steam (at 0.44 MPa and 177°C). The LP steam is then sent to the Stripper's Reboiler with a small part being fed to the deaerator (as supplementary steam for stripping).

The electricity produced by the Cogen Plant is used by the Hydrogen Plant, CO_2 capture plant, CO_2 compression and dehydration unit and other utilities. A small surplus is exported to the grid.

3.4.5. Demi-Water Plant and Cooling Water System

The Demi-Water and Cooling Water Systems of the plant are described in Section 2.4.3.

Once through seawater cooling (primary system) is used in the CO_2 Compression and Dehydration Unit. Whilst, the closed circuit cooling system (secondary system) is used by the CO_2 Capture Plant (i.e. trim coolers, condenser, et. al.).

3.4.6. Balance of Plant (BoP)

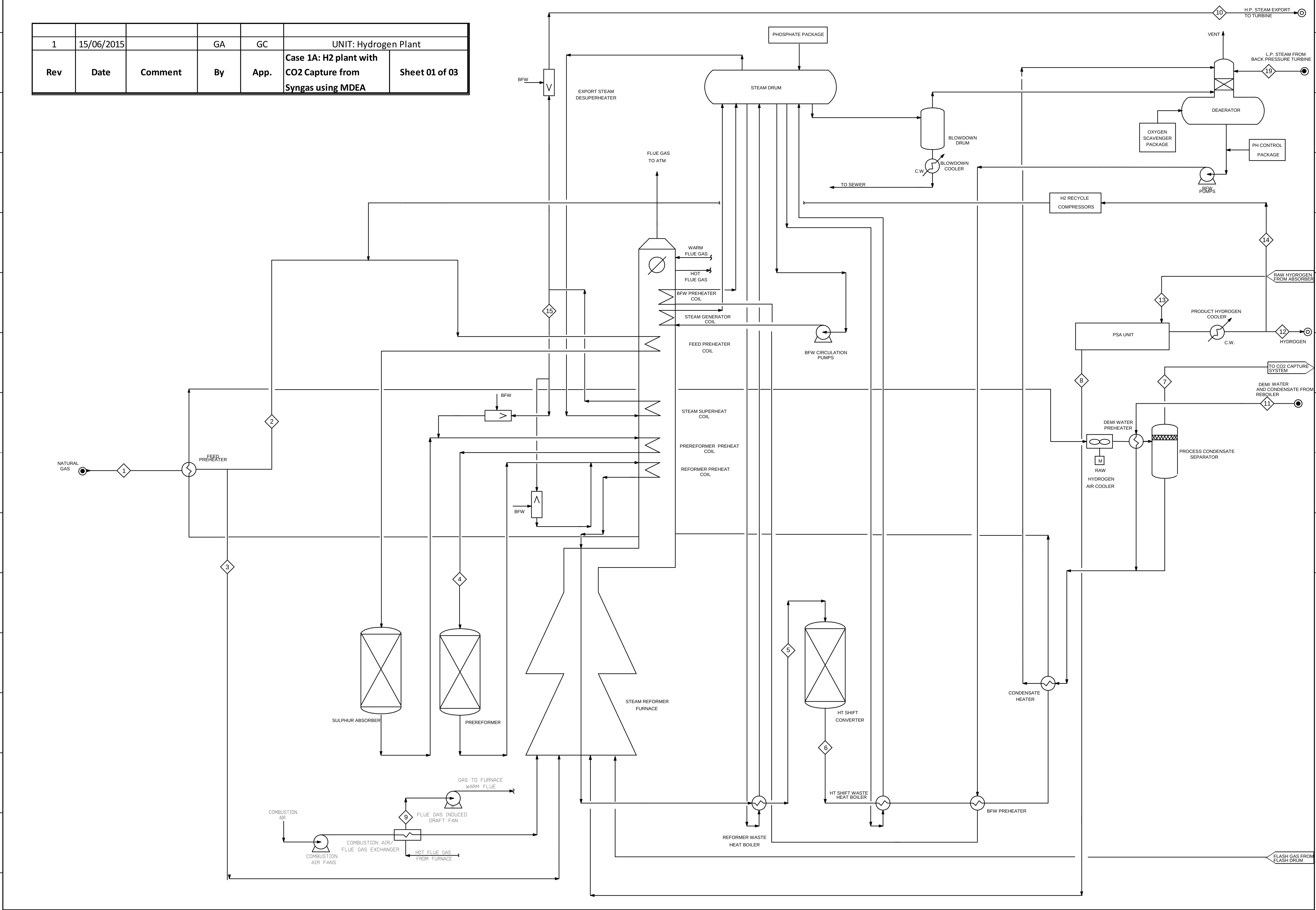
The operation of the whole plant is supported by additional utilities and facilities. These are presented in Section 2.4.4.

3.5. Process Flow Diagram (Hydrogen Plant and CO_2 Capture System)

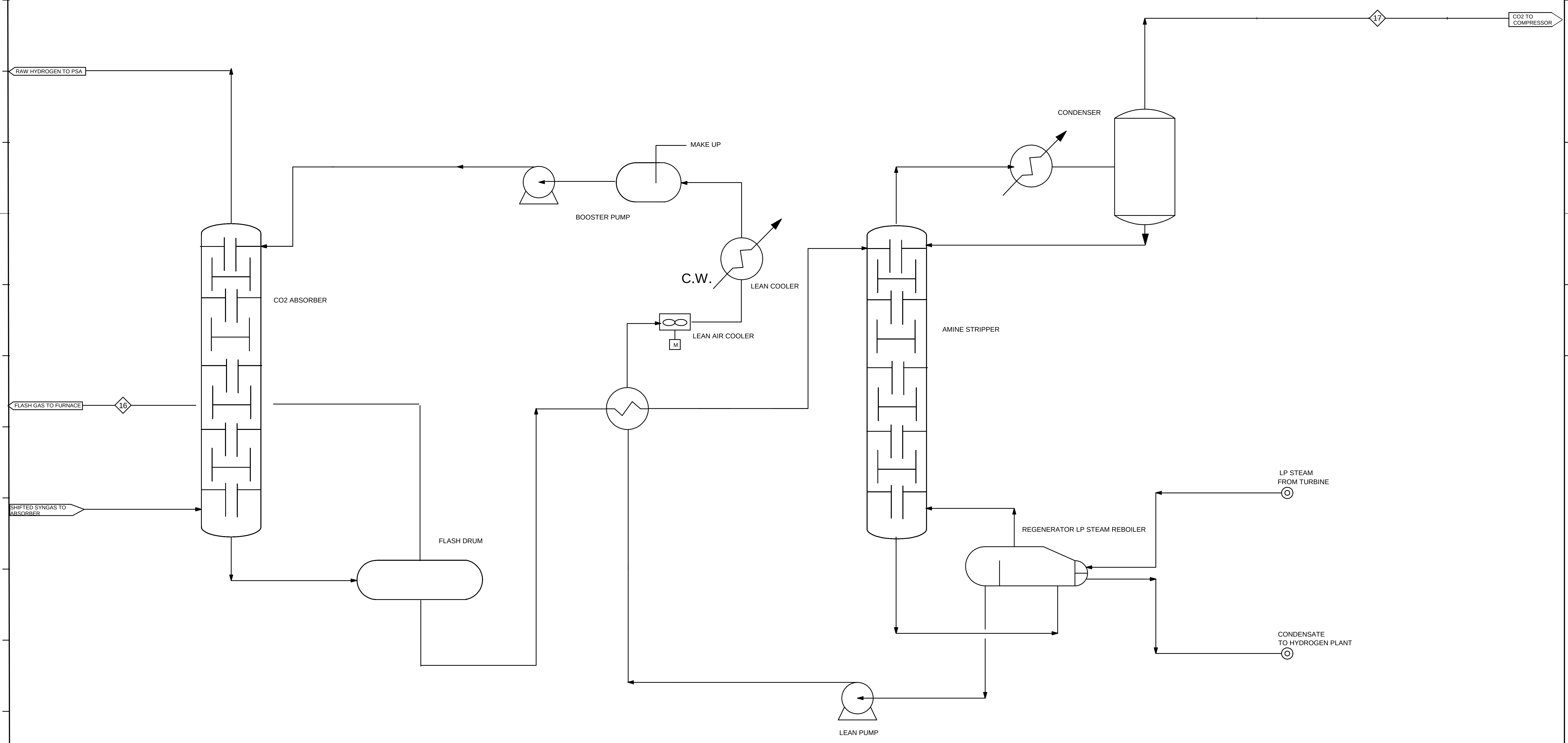
The PFDs enclosed shows the different processes included in the Hydrogen Plant, the CO_2 Capture Plant and the CO_2 Compression and Dehydration Unit.

The processes involving the Hydrogen Plant are described in Section 2.4. The changes made to the hydrogen plant (as compared to the Base Case) are described in Section 3.4. The processes involving the CO_2 capture plant and the CO2 Compression and Dehydration Unit are also described in Section 3.4.

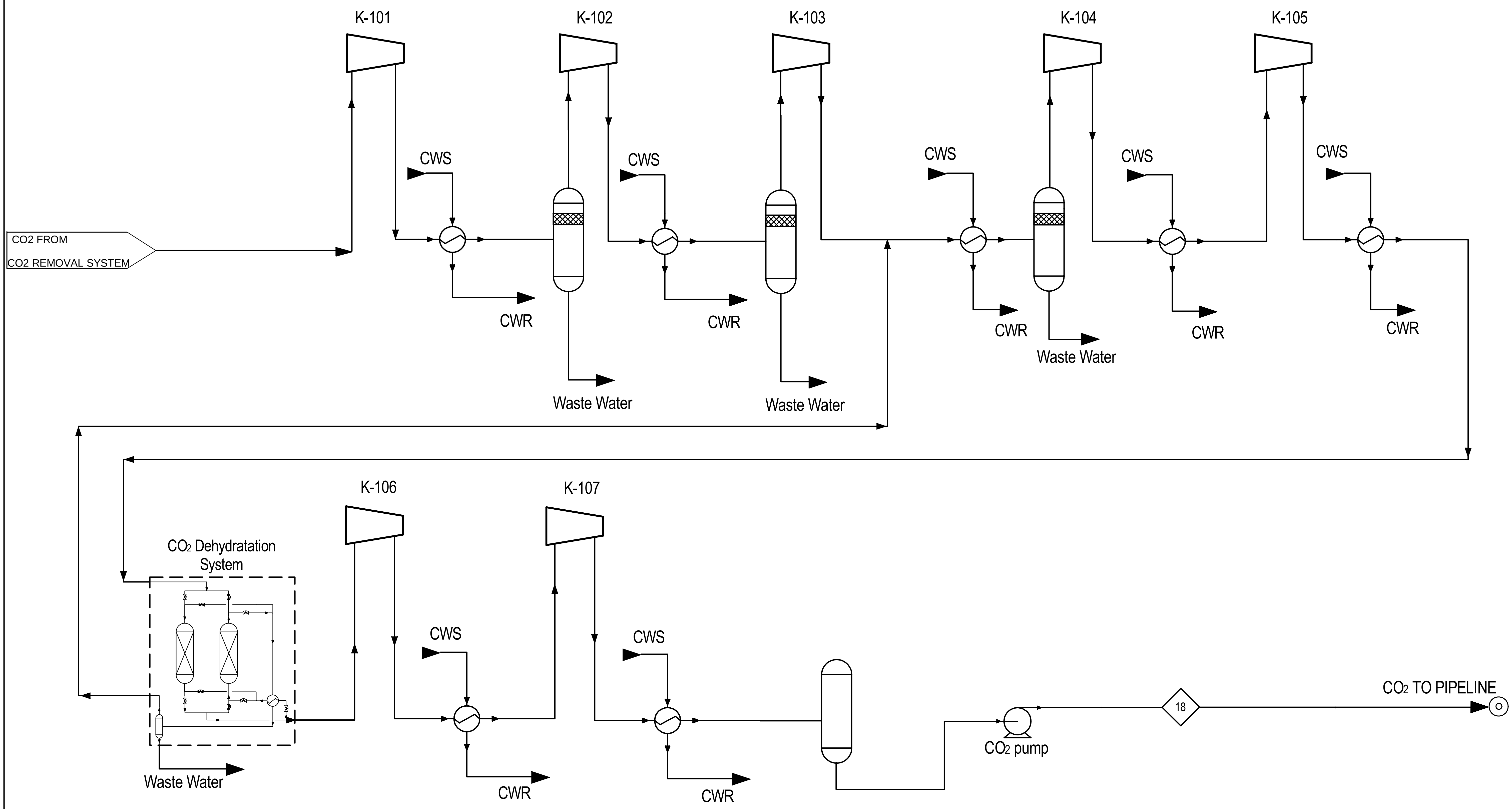
1	15/06/2015		GA	GC	UNIT: Hydrogen Plant	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 1A: H2 plant with CO2 Capture from Syngas using MDEA**	**Sheet 01 of 03**



1	15/06/2015		GA	GC	UNIT: CO2 Removal System	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 1A: H2 plant with CO2 Capture from Syngas using MDEA**	**Sheet 02 of 03**



1	15/06/2015		GA	GC	UNIT: CO2 Compressor	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 1A: H2 plant with CO2 Capture from Syngas using MDEA**	**Sheet 03 of 03**



3.6. Heat and Mass Balance

The heat and mass balances reported in this section makes reference to the Process Flow Diagram presented in Section 3.5.

FOSTER WHEELER		HEAT AND MATERIAL BALANCE Case 1A - Hydrogen Plant with CO2 capture from Syngas using MDEA				
CLIENT:	IEA GHG	**REV**	**DATE**	**BY**	**CHKD**	**APP**
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		1	2	3	4	5	6	7	8	9	10	11	12
Description		Natural Gas From B.L.	Natural Gas feedstock to Hydrogen Plant	Natural Gas fuel to burners	Purified Feedstock to Pre-reformer	HTS Reactor inllet	HTS Reactor Outlet	Raw Syngas to CO2 capture system	PSA Tail gas	Flue gas to ATM	HP Steam export	Demi Water (make up) and condensate from Stripper reboiler	Hydrogen to B.L
Temperature	*°C*	9	127	120	500	320	412	35	28	135	396	15	40
Pressure	*MPa*	7.00	3.73	0.50	3.41	2.82	2.79	2.60	0.13	0.02	4.23	0.60	2.50
Molar Flow	*kmol/h*	1751.6	1457.5	294.1	5520.5	8376.6	8376.6	6598.7	1047.6	8276.0	3617.7	6142.1	4461.5
Mass Flow	*kg/h*	31562	26262	5300	98991	101787	101787	69749	14055	229838	65172	110650	8994
Composition													
CO2	*mol/mol*	0.0200	0.0200	0.0200	0.0053	0.0493	0.1282	0.1627	0.0139	0.1017	0.0000	0.0000	0.0000
CO	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.1154	0.0365	0.0463	0.2915	(2)	0.0000	0.0000	0.0000
Hydrogen	*mol/mol*	0.0000	0.0000	0.0000	0.0053	0.5167	0.5957	0.7561	0.4763	0.0000	0.0000	0.0000	0.9999+
Nitrogen	*mol/mol*	0.0089	0.0089	0.0089	0.0023	0.0015	0.0015	0.0020	0.0124	0.6947	0.0000	0.0000	0.0000
Oxygen	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0119	0.0000	0.0000	0.0000
Methane	*mol/mol*	0.8900	0.8900	0.8900	0.2350	0.0240	0.0240	0.0305	0.1918	0.0000	0.0000	0.0000	0.0000
Ethane	*mol/mol*	0.0700	0.0700	0.0700	0.0185	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	*mol/mol*	0.0100	0.0100	0.0100	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	*mol/mol*	0.0010	0.0010	0.0010	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	*mol/mol*	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	*mol/mol*	0.0000	0.0000	0.0000	0.7307	0.2931	0.2141	0.0024	0.0140	0.1916	1.0000	1.0000	0.0000
Contaminants:													
H2S	*ppm v*	(1)											
NOx	*mg/Nm3*									120 max			

Notes:

(1) For feedstock purification section design purposes 5 ppmv of H2S have been assumed in NG to Hydrogen Plant

(2) 30 mg/Nm3 max

HEAT AND MATERIAL BALANCE
Case 1A - Hydrogen Plant with CO2 capture from Syngas using MDEA

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG	**REV**	**DATE**	**BY**	**CHKD**	**APP**
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		13	14	15	16	17	18	19					
Description		Raw Hydrogen to PSA	Recycle hydrogen	High pressure Steam to process	Flash gas to Steam Reformer Furnace	CO2 from capture plant to Compressor	CO2 to Pipeline	LP Steam from BP Turbine to Deareator					
Temperature	°C	41	40	400	71	49	24	177					
Pressure	MPa	2.58	2.51	4.29	0.60	0.29	11.00	0.44					
Molar Flow	kmol/h	5538.2	29.1	4162.1	4.4	1104.5	1059.4	35.6					
Mass Flow	kg/h	23108	59	74981	83	47411	46600	642					
Composition													
CO2	mol/mol	0.0026	0.0000	0.0000	0.3522	0.9586	0.9994	0.0000					
CO	mol/mol	0.0551	0.0000	0.0000	0.0295	0.0000	0.0000	0.0000					
Hydrogen	mol/mol	0.9009	0.9999+	0.0000	0.5353	0.0004	0.0004	0.0000					
Nitrogen	mol/mol	0.0023	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000					
Oxygen	mol/mol	0.0363	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000					
Methane	mol/mol	0.0000	0.0000	0.0000	0.0376	0.0001	0.0001	0.0000					
Ethane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000					
Propane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000					
n-Butane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000					
n-Pentane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000					
H2O	mol/mol	0.0026	0.0000	1.0000	0.0453	0.0409	0.0000	1.0000					
Contaminants:													
H2S	ppm v												
NOx	mg/Nm3												

Notes:

3.7. Plant Performance Data

The table below summarizes the energy performance and CO_2 emissions relevant to the Hydrogen Plant with CO_2 capture from Syngas using MDEA.

Plant Performance Data Case 1A		
INLET STREAMS		
Natural Gas (as Feedstock)	t/h	26.262
Natural Gas (as Fuel)	t/h	5.300
Natural Gas (Total Consumption)	t/h	31.562
Natural Gas LHV	MJ/kg	46.50
Total Energy Input	MW	407.68
OUTLET STREAMS		
Hydrogen Product to BL	t/h	8.994
	Nm^3/h	100,000
Hydrogen LHV	MJ/kg	119.96
Total Energy in the Product	MW	299.70
POWER BALANCE		
Gross Power Output from the COGEN Plant	MWe	6.700
Hydrogen Plant Power Consumption	MWe	-1.257
COGEN Plant + Utilities + BoP Consumption	MWe	-0.377
CO2 Capture Plant	MWe	-0.569
CO2 Compression and Dehydration Unit	MWe	-3.005
Excess Power to the Grid	MWe	1.492
SPECIFIC CONSUMPTIONS		
Natural Gas (as Feedstock)	GJ/1000 Nm^3 H_2	12.212
Natural Gas (as Fuel)	GJ/1000 Nm^3 H_2	2.465
Feed + Fuel	GJ/1000 Nm^3 H_2	14.676
SPECIFIC EMISSIONS		
Specific CO2 Emission	t/1000 Nm^3 H_2	0.3704
Specific CO2 Captured	t/1000 Nm^3 H_2	0.4660
Overall CO2 Capture Rate (Case Specific)		55.71%
Overall CO2 Capture Rate (as Compared to Base Case)		54.22%

3.8. Preliminary Utilities Consumption

This section presents the different utilities consumption (usage) of the Hydrogen Plant, Power Island, CO_2 Capture Plant, CO_2 Compression and Dehydration, and others.

ESTIMATED UTILITY CONSUMPTIONS

CUSTOMER NAME:	IEAGHG	**Case 1A: H2 Plant with CO2 Capture from Syngas using MDEA**	REV.	REV. 0	REV. 1	REV. 2					SHEET
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE		BY	GA							1
FWI CONTRACT:	1BD0840 A		CHKD	GC							OF
LOCATION:	THE NETHERLAND		DATE	April 2015							1

	ELECTRIC POWER		STEAM t / h			EFFLUENT	LOSSES	DMW	RAW WATER	COOLING WATER		SEA WATER		FUEL	INSTR. AIR	Nitrogen
	LOAD BHP	kW	LP	MP	HP	t/h	t/h	t/h	t/h	ΔT (°C)	m³/hr	ΔT (°C)	m³/hr	MMKcal/h	Nm^3/h	Nm^3/h
HYDROGEN PLANT		1,257	0.60	0.00		-1.97	-43.7 (2)	110.7 (1)	0.00	11	28.0			58.9	100	(250)
					-65.0											
CO2 CAPTURE		569	64.40					0.79		11	841					
								-64.4								
CO2 COMPRESSION		3,005								11	38	7	857			
POWER ISLAND					65.0											
		-6,700	-65.0													
UTILITIES / BoP		377				-14.1			61.2	11	-907	7	1,427	0.5	100	(250)
								-47.0							-200	(-500)
TOTAL		-1,492	0	0	0	-16.1	-43.7	0	61.2	-	0	-	2,284	59.4	0	0

NOTES:
(1) DMW is the sum of DMW plus condensate from CO2 capture unit reboiler
(2) Losses includes water consumed in the reaction and deaerator vent
(3) Water effluent (to be sent to WWT) includes demi plant eluate and steam drum blowdown in the hydrogen plant

3.9. Preliminary Equipment List and Size of Main Components/Packages

This section presents the preliminary list of equipment and main components/packages relevant to the Case 1A.

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	**CLIENT:**	IEA GHG	**0**	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						8
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	SIZE ID	SIZE L / H	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			mm	mm	MPa	°C				
DRUMS										
	FUEL GAS K.O. DRUM	VERTICAL								
	STEAM DRUM	HORIZONTAL								
	PROCESS CONDENSATE SEPARATOR	VERTICAL								
	BLOWDOWN DRUM	VERTICAL								
	DEAERATOR	Stripping Section: Vertical Storage Section: Horizontal								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						8
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	SIZE ID mm	SIZE L / H mm	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
REACTORS										
	SULPHUR ABSORBERS	VERTICAL	2450	3650	4.075	400				
	PRE-REFORMER	VERTICAL	2100	3050	4.075	530				
	SHIFT CONVERTER	VERTICAL	3400	4400	3.080	430				

FOSTER WHEELER

PRELIMINARY EQUIPMENT LIST

		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						8
LOCATION	THE NETHERLAND						
CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY MM kcal/h	AREA m^2	DESIGN PRESSURE SS / TS MPa	DESIGN TEMPERATURE SS / TS °C	MATERIAL	REMARKS		REV.
HEAT EXCHANGERS & COILS										
	FEED PRE-HEATER	SHELL & TUBE								
	HTS WASTE HEAT BOILER	SHELL & TUBE								
	BFW PRE-HEATER	SHELL & TUBE								
	CONDENSATE HEATER	SHELL & TUBE								
	DEMIWATER PRE-HEATER	SHELL & TUBE								
	BLOWDOWN COOLER	SHELL & TUBE								
	HYDROGEN PRODUCT COOLER	SHELL & TUBE								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	4
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
					SS / TS	SS / TS				
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS & COILS										
	COMBUSTION AIR / FLUE GAS EXCHANGER									
	BFW PREHEATER COIL	COIL								
	STEAM GENERATOR COIL	COIL								
	STEAM SUPERHEATER COIL	COIL								
	FEED PREHEATER COIL	COIL								
	PRE-REFORMER FEED PREHEATER COIL	COIL								
	REFORMER FEED PREHEATER COIL	COIL								
	REFORMER WASTE HEAT BOILER	SHELL & TUBE								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	5
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						8
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	DUTY	SIZE		DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			WIDTH	LENGTH						
		MM Kcal/h	mm	mm	MPa	°C	HEADER/TUBES			
AIR COOLERS										
	RAW HYDROGEN AIR COOLER									
FIRED EQUIPMENT										
	STEAM REFORMER FURNACE	82.63 (**)						(**) Radiant Duty		

FOSTER WHEELER

PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	6
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						
LOCATION	THE NETHERLAND						8
CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	HEAD	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			m^3/h	m	MPa	kW	CASING/IMPELLER			
PUMPS										
	BFW CIRCULATION PUMPS	Centrifugal								
	BFW FEED PUMPS	Centrifugal						Two pumps electrical motor driven		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	8
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						8
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	°C				
MISCELLANEA										
	STEAM VENT SILENCER									
	REFORMER STEAM DESUPERHEATER									
	PREREFORMER STEAM DESUPERHEATER									
	PHOSPHATE PACKAGE									
	EXPORT STEAM DESUPERHEATER									
	OXYGEN SCAVENGER PACKAGE									
	pH CONTROL PACKAGE									
	PSA UNIT		124128	2.58/2.51 (H2 side)	2.8	80				

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						5
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	SIZE ID	SIZE L / H	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			mm	mm	MPa	°C				
TOWERS										
	ABSORBER	VERTICAL	3361	20000	28 & F.V	150				
	STRIPPER	VERTICAL	4893	20000	3.5 & F.V	170				
DRUMS										
	FLASH DRUM	HORIZONTAL								
	AMINE SOLUTION TANK	HORIZONTAL								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE	1	June 2015	GA	GC	GC	OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	DUTY MM kcal/h	AREA m^2	DESIGN PRESSURE SS / TS MPa	DESIGN TEMPERATURE SS / TS °C	MATERIAL	REMARKS		REV.
HEAT EXCHANGERS										
	LEAN/RICH AMINE EXCHANGER	SHELL & TUBE								
	LEAN AMINE TRIM COOLER	SHELL & TUBE								
	STRIPPER CONDENSER									
	STRIPPER REBOILER	KETTLE								
	LEAN AMINE AIR COOLER									

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	DUTY MM kcal/h	AREA m^2	DESIGN PRESSURE SS / TS MPa	DESIGN TEMPERATURE SS / TS °C	MATERIAL	REMARKS		REV.
PUMPS										
	BOOSTER PUMPS	CENTRIFUGAL	Power: 464.74							
	LEAN PUMP	CENTRIFUGAL								
	AMINE SOLUTION PUMP									
	CO2 PUMP (CO2 COMPRESSOR PACKAGE)	CENTRIFUGAL								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	4
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
COMPRESSORS & BLOWERS										
	CO2 COMPRESSORS	CENTRIFUGAL	24745					Brake Power: 2939 kW seven Stages, Pin= 0.29 MPa, Pout= 11 MPa, Tin =49°C, Tout=24°C, MW=42.9, Electical motor to be included Compressor Package includes 3 separators and seven trim coolers		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	5
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						5
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW Nm^3/h	PRESSURE INLET/OUTLET MPa	DESIGN PRESSURE MPa	Brake Power kW	MATERIAL CASING/IMPELLER	REMARKS		REV.
MISCELLANEA										
	DRYER UNIT PACKAGE	MOLSIV	26448					max H2O in outlet stream= 50 ppm v		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						1
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	POWER ISLAND						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
POWER ISLAND										
	STEAM TURBINE AND GENERATOR PACKAGE									
	Including									
	STEAM TURBINE	Backpressure type	7 MWe	4.2 / 0.55				Including: lube oil system; Cooling system; Hydraulic control system; Seal system Drainage system Gland condenser		
	STEAM TURBINE GENERATOR		9 MVA					Including relevant auxiliaries		
	STEAM TURBINE BYPASS SYSTEM									

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						3
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
COOLING WATER SYSTEM										
	SEA WATER PUMPS	Centrifugal	2500 m3/h x 25 m 250 kWe					One operating one spare		
	SEA WATER / CLOSED COOLING WATER EXCHANGER		11.6 MWth							
	CLOSED COOLING WATER PUMPS		1000 m3/h x 25 m 110 kWe					One operating one spare		
	CLOSED COOLING WATER CIRCUIT EXPANSION DRUM									
	CORROSION INHIBITOR PACKAGE									
INSTRUMENT / PLANT AIR SYSTEM										
	AIR COMPRESSOR PACKAGE							including: - Air Compressor - Inter/after coolers - KO Drums (including final KO drum)		
	AIR DRYING PACKAGE	Adsorption bed	200 Nm3/h					including: - Adsorbent Bed (with automatic regenaration system) - Regeneration Electrical Heater - Pre Filters - After Filters		
	IA RECEIVER DRUM	vertical								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						3
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
RAW / DEMI WATER SYSTEM										
	RAW WATER TANK	Fixed roof						12 h storage		
	RAW WATER FILTRATION PACKAGE		65 m3/h							
	POTABLE WATER TANK	Fixed roof						12 h storage		
	POTABLE WATER PACKAGE									
	DEMI WATER PLANT FEED PUMP		65 m3/h x 25 m 7.5 kW							
	DEMI WATER PACKAGE UNIT		50 m3/h DW production					Including: - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system		
	DEMIWATER PUMPS		50 m3/h x 50 m 15 kW							
	DEMIWATER TANK	Fixed roof						12 h storage		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						3
	LOCATION	THE NETHERLAND						
	CASE	CASE 1A: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE -	PRESSURE INLET/OUTLET MPa	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
NITROGEN GENERATION PACKAGE										
	NITROGEN PRODUCTION PACKAGE		500 Nm3/h					Including: - Intake Air Filter - Air Compressor - Air Receiver - Inter/after coolers - KO Drums - Molecular Sieve Water Absorber (Air Dryer) - Chiller Unit - One Expansion Turbine - One Cryogenic Distillation Column - One Main Heat Exchanger		
	LIQUID NITROGEN STORAGE AND VAPORISATION PACKAGE		500 Nm3/h					Including: - Liquid Nitrogen Storage tank - Nitrogen Vaporizer (Air Fin Type) - Nitrogen heater (electrical)		
	GASEOUS NITROGEN BUFFER VESSEL									
FLARE SYSTEM										
	FLARE KO DRUM	Horizontal								
	FLARE PACKAGE		Max relief flowrate 102,000 kg/h; MW:12					Including riser; tip, seal drum		
	FLARE KO DRUM PUMPS	Centrifugal						One operating one spare		
BoP										
	INTERCONNECTING									
	BUILDING (CONTROL ROOM, ELECTRICAL SUBSTATION, LAB)									
	DRAIN SYSTEM									
	FIRE FIGHTING									
	ELECTRICAL SYSTEM							Up to generator terminals		

4. Case 1B

4.1. Basis of Design

This section should be referred to the Annex I - Reference Document (Task 2) - for the general plant design criteria and assumptions used in the development of Case 1B (Hydrogen Plant with H_2-Rich Fuel Firing Burners and CO_2 Capture from Syngas using MDEA).

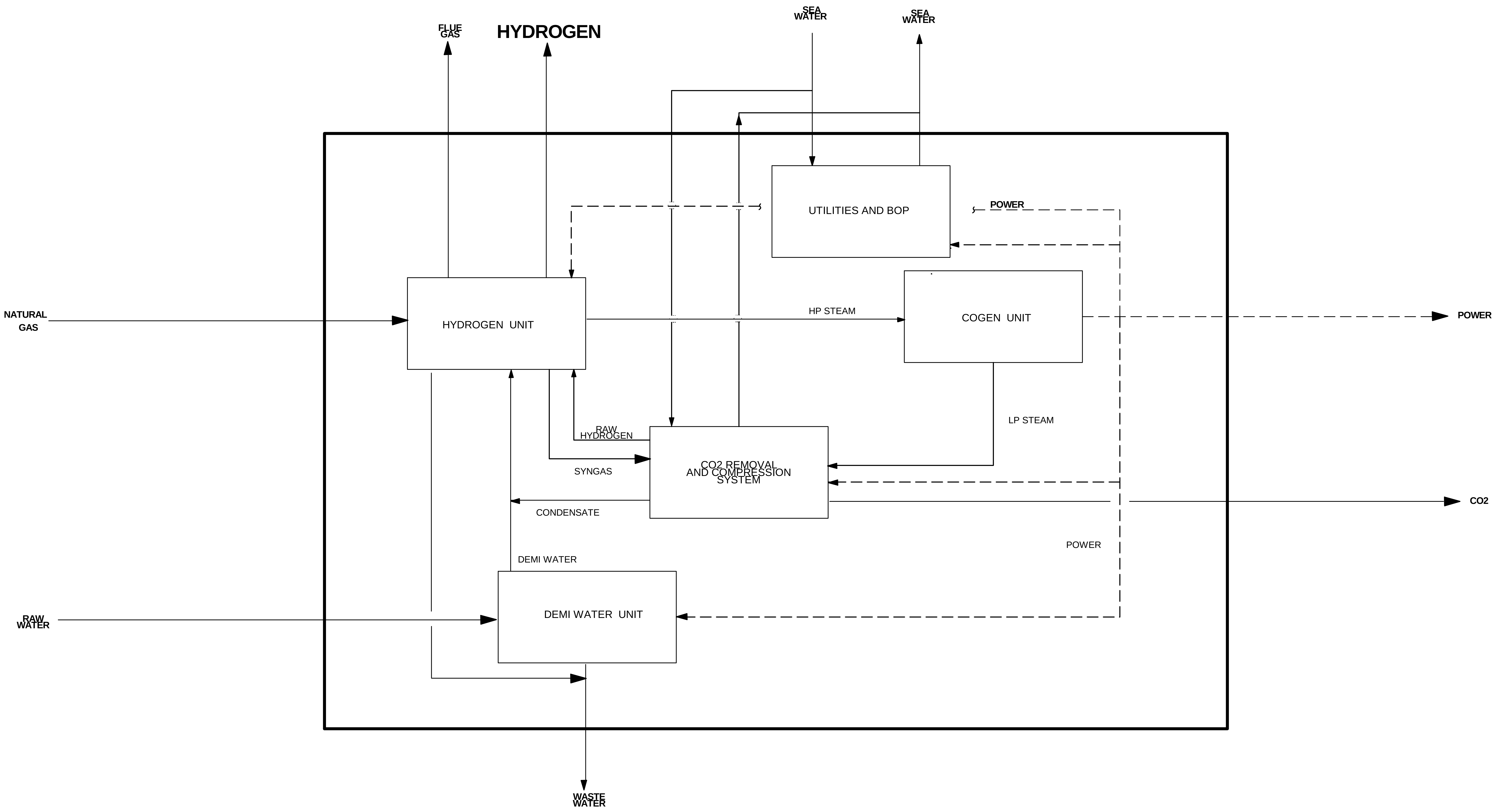
4.2. Units Arrangement

The units included in Case 1B (Hydrogen Plant with H_2-Rich Fuel Firing Burners and CO_2 Capture from Syngas using MDEA) are as follows:

- Hydrogen Plant
- Cogen Plant (Power Island)
- CO_2 Capture System (Capture from Shifted Syngas using MDEA)
- CO_2 compression and dehydration
- Demi-Water Plant
- Utilities and Balance of Plant (BoP), consisting of:
  - Cooling Water System
  - Instrument/Plant Air System
  - Nitrogen Generation Package
  - Flare System
  - Interconnecting
  - Drain System
  - Buildings (Control Room, Laboratories, Electrical Sub-Station).

4.3. Overall Block Flow Diagram

The BFD presented in the next page shows the different unit processes and the relevant inlet/outlet streams included in the Hydrogen Plant for Case 1B (with H_2 Rich Fuel Firing Burners and CO_2 Capture from Syngas using MDEA).



Battery Limits Summary

	Inlet Streams			Outlet Streams				
	Natural Gas From B.L.	Raw Water	Sea Water	Hydrogen	Flue gas to ATM	Power	Captured CO2	Waste Water
	Kg/h	Kg/h	m3/h	Kg/h	Kg/h	kW	kg/h	kg/h
Flow rate	33333	77300	2887	8994	260952	1542	58985	19300

Rev	Date	Comment	By	App.	UNIT: Overall Block Flow Diagram	
1	15/06/2015		GA	GC	Case 1B - Hydrogen Plant with CO2 capture from syngas using MDEA with H2-Rich Fuel Firing Burners	Sheet 01of 01

4.4. Process Description

This section makes reference to the Process Flow Diagram of the SMR based hydrogen plant with CO_2 capture from shifted syngas presented in Section 4.5.

This section should be referred to Section 2.4.1 for the description of the Hydrogen Plant and associated steam production and BFW system; Section 3.4 for the description of the CO_2 Capture Plant, CO_2 Compression and Dehydration Unit, and Demi-Water and Seawater Cooling Systems.

4.4.1. Hydrogen Plant

The Hydrogen Plant assumed in Case 1B should have similar scheme to the Hydrogen Plant reported in Case 1A except that the syngas production capacity has been increased to produce more syngas – i.e. given the assumption that natural gas (as supplementary fuel) has been substituted with the sweet syngas from the CO_2 capture plant. This therefore correspond to higher natural gas consumption (as feedstock) as compared to the Base Case.

In this regard, the SMR is fired with the PSA tail gas as primary fuel and with the sweet syngas from the CO_2 capture plant as supplementary fuel. The firing system of the SMR plant is based on burning of H_2 rich fuel where the technical considerations relevant to NOx emission are described in the next section.

The capacity and size of the PSA unit used in Case 1B should have the same size and capacity of the PSA unit deployed in Case 1A (given that the H_2 production capacity is kept constant).

The steam generation capacity (i.e. reformer waste heat boiler, shift converter waste heat boiler, steam generating coil and steam superheater coil) and all other heat exchange equipment (Feed-Pre-heater Coil, Pre-Reformer Feed Pre-heater Coil, Reformer Feed Pre-Heater Coil, et. al.) are sized accordingly to accommodate the larger volume of syngas produced (as compared to Case 1A).

4.4.2. Considerations on Hydrogen-Rich Fuel Burners

The source of information presented in this section are obtained from John Zinc / Hamworthy Combustion.

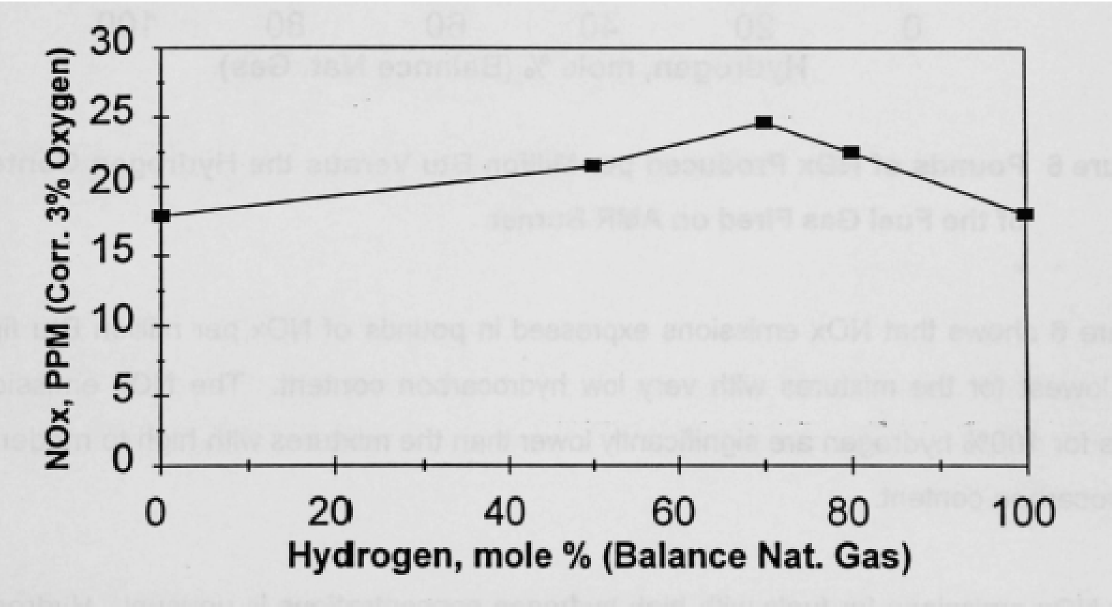
The fuel gas composition has a significant impact to the burner's NOx emission performance because it directly affects the temperature profile in the flame zone.

When firing natural gas, the NO_x emissions are generally produced from the combination of thermal and prompt NO_x mechanisms.

The thermal NO_x is primarily generated by the reaction between N_2 and O_2 contained in the combustion air. The thermal NOx production increases exponentially with peak flame temperatures. It should be noted that H_2 has a higher adiabatic flame temperature than natural gas therefore it has a higher potential to promote thermal NO_x production.

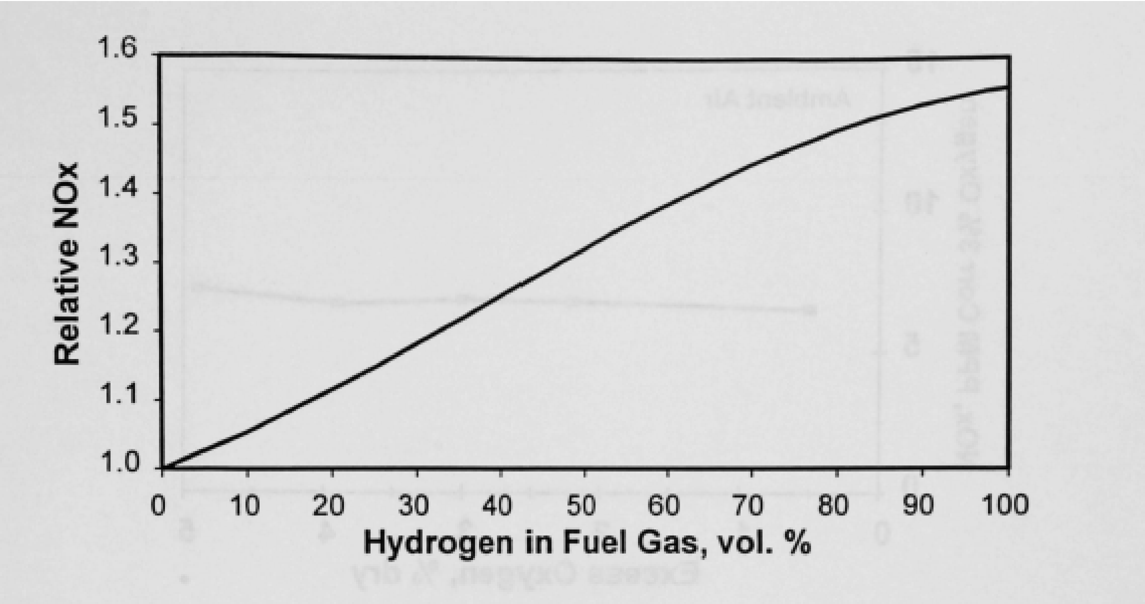
On the other hand, Prompt NO_x is formed via several mechanisms, but mainly with the reaction between N_2 and hydrocarbon radicals (i.e. C and CH). In other words, the prompt NOx mechanism requires the presence of carbon-containing radicals which are not present when burning H_2.

If H_2 is mixed with natural gas, the NO_x emission tends to increase and reaches its peak when the fuel gas containing around 70% H_2 (with NG as the balance) is burned. After which, the NOx emission tends to decrease as the proportion of the natural gas decreases (as shown in figure below).



The increase in the NOx emission could be attributed to the increase in thermal NOx emission (due to higher H_2 content); whilst the reduction of the NOx emissions as H_2 content reaches 100% could be attributed to the reduction in the prompt NOx mechanism.

For conventional burners, it could be noted that the peak NO_x emissions could occur when firing 100% hydrogen (see figure below).



If thermal NO_x emissions are controlled to a relatively low levels (e.g. with the use of low/ultra-low NO_x burners), it should be expected that NOx emission could also be reduced once the fuel gas contain less hydrocarbon (i.e. for the case when firing H_2).

As far as burners cost is concern, it is considered in this study that there is no difference between low NO_x burners using natural gas vs. burners firing hydrogen-rich fuel.

4.4.3. CO_2 Capture Plant (MDEA based Chemical Absorption Technology)

The CO_2 capture plant for Case 1B is also based on chemical absorption technology using MDEA as solvent and has similar scheme to the CO_2 capture plant as described in Case 1A except that it would need to handle larger volume of shifted syngas.

As such, the description for the CO_2 Capture Plant should be referred to Section 3.4.2.

4.4.4. CO_2 Compression and Dehydration

The CO_2 compression and dehydration unit for Case 1B has similar scheme to the CO_2 compression and dehydration unit as described in Case 1A except that it would need to handle larger volume of captured CO_2.

As such, the description for the CO_2 Capture Plant should be referred to Section 3.4.3.

4.4.5. *Cogen Plant (Power Island)*

The Cogen Plant for Case 1B is also based a back pressure type steam turbine as described in Section 3.4.4.

4.4.6. *Demi-Water and Cooling Water System*

The Demi-Water Plant and Cooling Water System for Case 1B has similar scheme used in Case 1A as described in Section 3.4.5.

4.4.7. *Balance of Plant (BoP)*

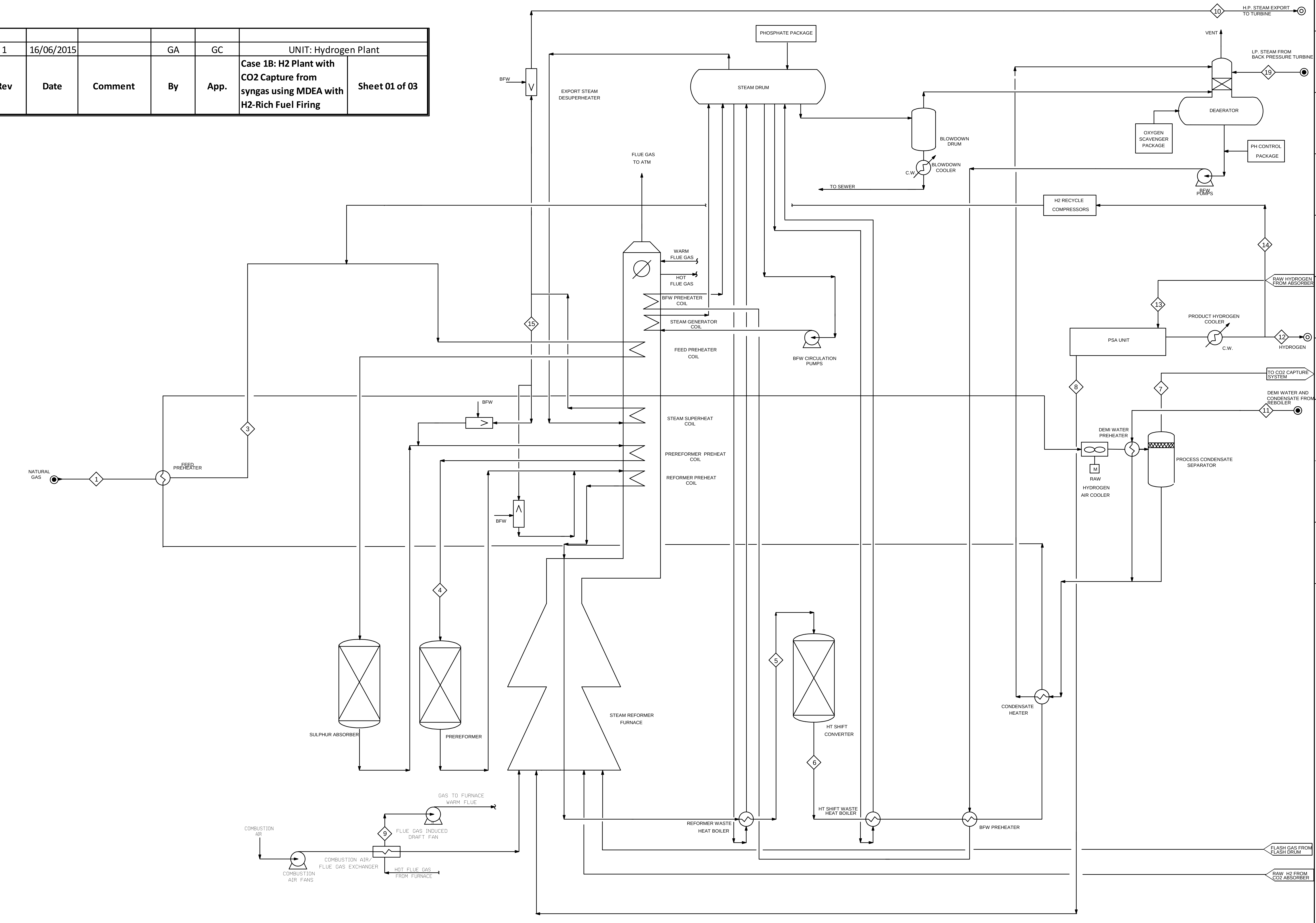
The operation of the whole plant is supported by additional utilities and facilities. These are presented in Section 2.4.4.

4.5. Process Flow Diagram (Hydrogen Plant and CO_2 Capture System)

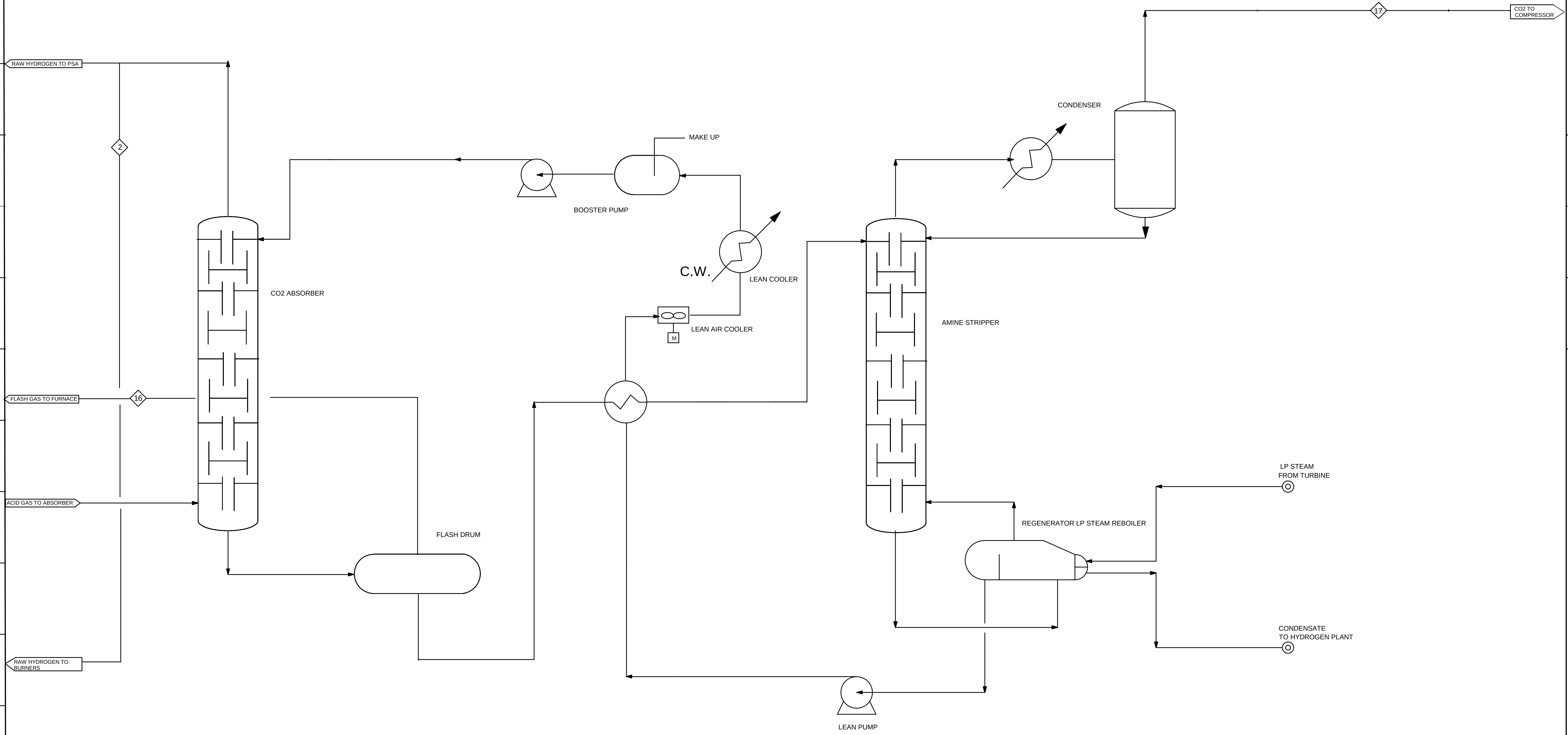
The PFDs enclosed shows the different processes included in the Hydrogen Plant, the CO_2 Capture Plant and the CO_2 Compression and Dehydration Unit.

The processes involving the Hydrogen Plant are described in Section 2.4. The processes involving the CO_2 capture plant and the CO_2 Compression and Dehydration Unit are described in Section 3.4.

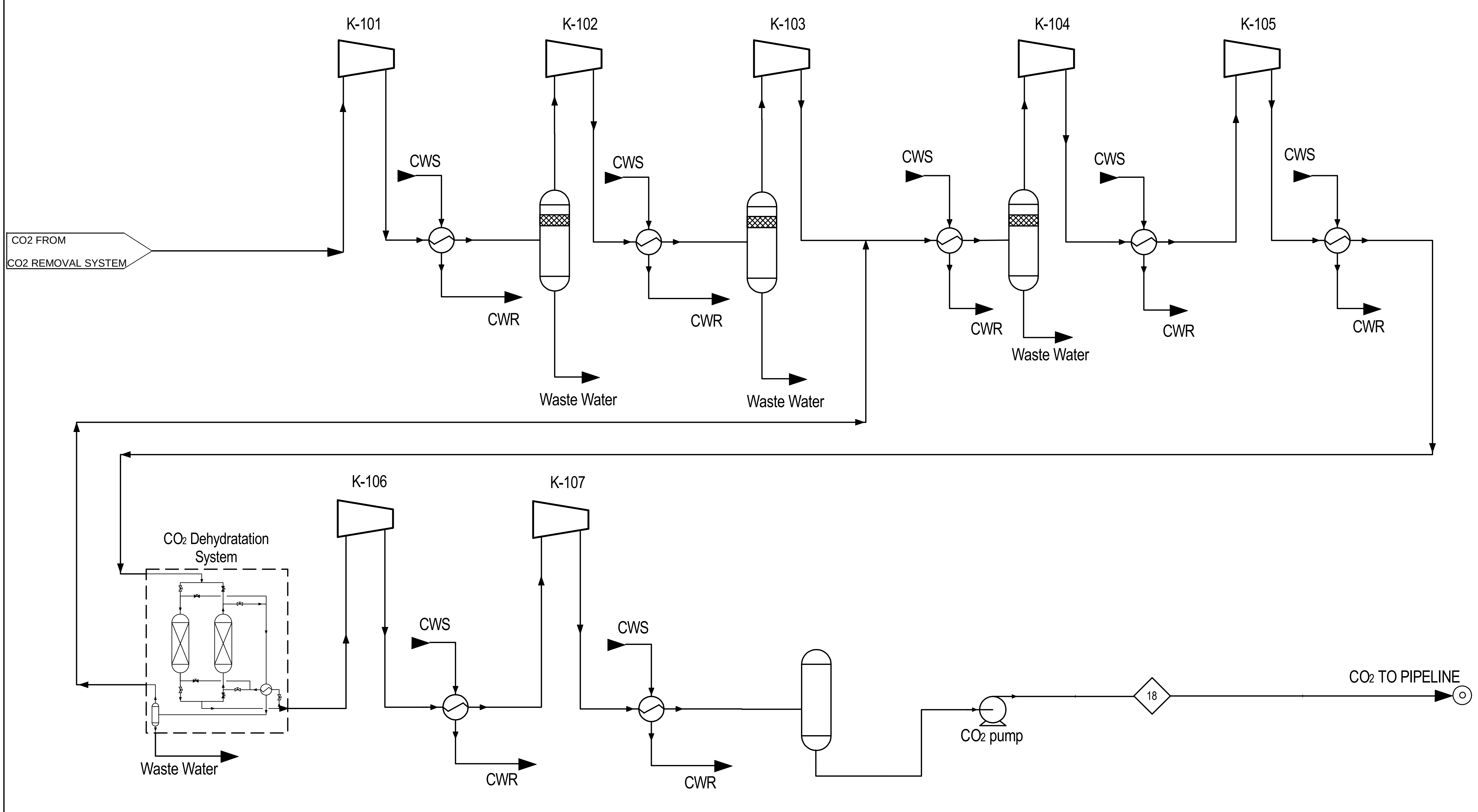
1	16/06/2015		GA	GC	UNIT: Hydrogen Plant	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 1B: H2 Plant with CO2 Capture from syngas using MDEA with H2-Rich Fuel Firing**	**Sheet 01 of 03**



1	16/06/2015		GA	GC	UNIT: CO_2 Removal System	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 1B: H2 Plant with CO_2 Capture from syngas using MDEA with H2-Rich Fuel Firing Burners**	**Sheet 02 of 03**



1	16/06/2015		GA	GC	UNIT: CO2 Compressor	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 1B: H2 Plant with CO2 Capture from syngas using MDEA with H2-Rich Fuel Firing Burners**	**Sheet 03 of 03**



4.6. Heat and Mass Balance

The heat and mass balances reported in this section makes reference to the Process Flow Diagram presented in Section 4.5.

FOSTER WHEELER

HEAT AND MATERIAL BALANCE
Case 1B - Hydrogen Plant with CO2 capture from syngas using MDEA with H2-Rich Fuel Firing Burners

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG					
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		1	2	3	4	5	6	7	8	9	10	11	12
Description		Natural Gas From B.L.	Raw Hydrogen To Burners	Natural Gas feedstock to Hydrogen Plant	Purified Feedstock to Pre-reformer	HTS Reactor Inlet	HTS Reactor Outlet	Raw Syngas to CO2 capture system	PSA Tail gas	Flue gas to ATM	HP Steam export	Demi Water (make up) and condensate from Stripper reboiler	Hydrogen to B.L
Temperature	*°C*	9	41	127	500	320	412	35	28	135	397	15	40
Pressure	*MPa*	7.00	2.58	3.73	3.41	2.82	2.79	2.60	0.13	0.02	4.23	0.60	2.50
Molar Flow	*kmol/h*	1849.9	1481.5	1849.9	7006.9	10632.1	10632.1	8375.5	1049.4	9793.5	4359.5	7560.3	4461.5
Mass Flow	*kg/h*	33333	6181	33333	125645	129194	129194	88529	14080	260952	78537	136200	8994
Composition													
CO2	*mol/mol*	0.0200	0.0026	0.0200	0.0053	0.0493	0.1282	0.1627	0.0139	0.0677	0.0000	0.0000	0.0000
CO	*mol/mol*	0.0000	0.0551	0.0000	0.0000	0.1154	0.0365	0.0463	0.2915	(2)	0.0000	0.0000	0.0000
Hydrogen	*mol/mol*	0.0000	0.9009	0.0000	0.0053	0.5167	0.5957	0.7561	0.4763	0.0000	0.0000	0.0000	0.9999+
Nitrogen	*mol/mol*	0.0089	0.0023	0.0089	0.0023	0.00155	0.0015	0.0020	0.0124	0.6712	0.0000	0.0000	0.0000
Oxygen	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0113	0.0000	0.0000	0.0000
Methane	*mol/mol*	0.8900	0.0363	0.8900	0.2350	0.02399	0.0240	0.0305	0.1918	0.0000	0.0000	0.0000	0.0000
Ethane	*mol/mol*	0.0700	0.0000	0.0700	0.0185	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	*mol/mol*	0.0100	0.0000	0.0100	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	*mol/mol*	0.0010	0.0000	0.0010	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	*mol/mol*	0.0001	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	*mol/mol*	0.0000	0.0026	0.0000	0.7307	0.29307	0.2141	0.0024	0.0140	0.2497	1.0000	1.0000	0.0000
Contaminants:													
H2S	*ppm v*	(1)											
NOx	*mg/Nm3*									120 max			

Notes:

(1) For feedstock purification section design purposes 5 ppmv of H2S have been assumed in NG to Hydrogen Plant

(2) 30 mg/Nm3 max

HEAT AND MATERIAL BALANCE
Case 1B - Hydrogen Plant with CO2 capture from syngas using MDEA with H2-Rich Fuel Firing Burners

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG	**REV**	**DATE**	**BY**	**CHKD**	**APP**
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		13	14	15	16	17	18	19
Description		Raw Hydrogen to PSA	Recycle Hydrogen	HP Steam to process	Flash gas to Reformer Furnace	CO2 from capture plant to Compressor	CO2 to Pipeline	LP steam from BP turbine to Deareator
Temperature	°C	41	40	400	71	49	24	177
Pressure	MPa	2.58	2.51	4.29	0.60	0.29	11.00	0.44
Molar Flow	kmol/h	5548.0	37.0	5290.1	5.7	1400.0	1341.0	43.3
Mass Flow	kg/h	23149	75	95301	108	60053	59004	780
Composition								
CO2	mol/mol	0.0026	0.0000	0.0000	0.3522	0.9586	0.9995	0.0000
CO	mol/mol	0.0551	0.0000	0.0000	0.0295	0.0000	0.0000	0.0000
Hydrogen	mol/mol	0.9009	0.9999+	0.0000	0.5353	0.0004	0.0004	0.0000
Nitrogen	mol/mol	0.0023	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000
Oxygen	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane	mol/mol	0.0363	0.0000	0.0000	0.0376	0.0001	0.0001	0.0000
Ethane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	mol/mol	0.0026	0.0000	1.0000	0.0453	0.0409	0.0000	1.0000
Contaminants:								
H2S	ppm v							
NOx	mg/Nm3							

Notes:

4.7. Plant Performance Data

The table below summarizes the energy performance and CO_2 emissions relevant to the Hydrogen Plant with H_2 Rich Fuel Firing System and CO_2 capture from Syngas using MDEA.

Plant Performance Data Case 1B		
INLET STREAMS		
Natural Gas (as Feedstock)	t/h	33.333
Natural Gas (as Fuel)	t/h	-
Natural Gas (Total Consumption)	t/h	33.333
Natural Gas LHV	MJ/kg	46.50
Total Energy Input	MW	430.55
OUTLET STREAMS		
Hydrogen Product to BL	t/h	8.994
	Nm^3/h	100,000
Hydrogen LHV	MJ/kg	119.96
Total Energy in the Product	MW	299.70
POWER BALANCE		
Gross Power Output from the COGEN Plant	MWe	8.000
Hydrogen Plant Power Consumption	MWe	-1.582
COGEN Plant + Utilities + BoP Consumption	MWe	-0.440
CO2 Capture Plant	MWe	-0.717
CO2 Compression and Dehydration Unit	MWe	-3.719
Excess Power to the Grid	MWe	1.542
SPECIFIC CONSUMPTIONS		
Natural Gas (as Feedstock)	GJ/1000 Nm^3 H_2	15.500
Natural Gas (as Fuel)	GJ/1000 Nm^3 H_2	-
Feed + Fuel	GJ/1000 Nm^3 H_2	15.500
SPECIFIC EMISSIONS		
Specific CO2 Emission	t/1000 Nm^3 H_2	0.2918
Specific CO2 Captured	t/1000 Nm^3 H_2	0.5899
Overall CO2 Capture Rate (Case Specific)		66.90%
Overall CO2 Capture Rate (as Compared to Base Case)		63.93%

4.8. Preliminary Utilities Consumption

This section presents the different utilities consumption (usage) of the Hydrogen Plant, Power Island, CO_2 Capture Plant, CO_2 Compression and Dehydration, and others.

ESTIMATED UTILITY CONSUMPTIONS

CUSTOMER NAME: IEAGHG		**Case 1B - Hydrogen Plant with CO2 capture from syngas using MDEA with H2-Rich Fuel Firing Burners**	REV.	REV. 0	REV. 1	REV. 2		SHEET 1 OF 1
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE		BY	GA				
FWI CONTRACT:	1BD0840 A		CHKD	CG				
LOCATION:	THE NETHERLAND		DATE	April 2015				

	ELECTRIC POWER		STEAM t / h			EFFLUENT	LOSSES	DMW	RAW WATER	COOLING WATER		SEA WATER		FUEL	INSTR. AIR	Nitrogen
	LOAD BHP	kW	LP	MP	HP	t/h	t/h	t/h	t/h	ΔT (°C)	m³/hr	ΔT (°C)	m³/hr	MMKcal/h	Nm^3/h	Nm^3/h
HYDROGEN PLANT		1582	0.78	0.00		-1.48	-56.2 (2)	136.2 (1)	0.00	11	30.7				100	(250)
					-78.5											
CO2 CAPTURE		717	77.8					1.03		11	1068					
								-77.8								
CO2 COMPRESSION		3719								11	47	7	1085			
POWER ISLAND					78.5											
		-8,000	-78.5													
UTILITIES / BoP		440				-17.8			77.3	11	-1146	7	1802	0.5	100	(250)
								-59.5							-200	(-500)
TOTAL		-1,542	0	0	0	-19.3	-56.2	0	77.3	-	0	-	2,887	0.5	0	0

NOTES:

(1) DMW is the sum of DMW plus condensate from CO2 capture unit reboiler

(2) Losses includes water consumed in the reaction and deaerator vent

(3) Water effluent (to be sent to WWT) includes demi plant eluate and steam drum blowdown in the hydrogen plant

4.9. Preliminary Equipment List and Size of Main Components/Packages

This section presents the preliminary list of equipment and main components/packages relevant to the Case 1B.

c FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						7
	CASE	CASE 1B: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA WITH H2 RICH FUEL FIRING BURNERS						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	SIZE ID	SIZE L / H	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			mm	mm	MPa	°C				
DRUMS										
	FUEL GAS K.O. DRUM	VERTICAL								
	STEAM DRUM	HORIZONTAL								
	PROCESS CONDENSATE SEPARATOR	VERTICAL								
	BLOWDOWN DRUM	VERTICAL								
	DEAERATOR	Stripping Section: Vertical Storage Section: Horizontal								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						7
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	SIZE ID mm	SIZE L / H mm	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
REACTORS										
	SULPHUR ABSORBERS	VERTICAL	2700	3880	4.075	400				
	PRE-REFORMER	VERTICAL	2150	3190	4.075	530				
	SHIFT CONVERTER	VERTICAL	3700	4740	3.080	430				

PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						
LOCATION	THE NETHERLAND						
CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						7
UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS & COILS										
	FEED PRE-HEATER	SHELL & TUBE								
	HTS WASTE HEAT BOILER	SHELL & TUBE								
	BFW PRE-HEATER	SHELL & TUBE								
	CONDENSATE HEATER	SHELL & TUBE								
	DEMIWATER PRE-HEATER	SHELL & TUBE								
	BLOWDOWN COOLER	SHELL & TUBE								
	HYDROGEN PRODUCT COOLER	SHELL & TUBE								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST	REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT: IEA GHG	0	April 2015	GA	GC	GC	4
	PROJECT NAME: TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT: 1BD0840A						7
	LOCATION: THE NETHERLAND						
	CASE: HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						
	UNIT: HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
					SS / TS	SS / TS				
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS & COILS										
	COMBUSTION AIR / FLUE GAS EXCHANGER									
	BFW PREHEATER COIL	COIL								
	STEAM GENERATOR COIL	COIL								
	STEAM SUPERHEATER COIL	COIL								
	FEED PREHEATER COIL	COIL								
	PRE-REFORMER FEED PREHEATER COIL	COIL								
	REFORMER FEED PREHEATER COIL	COIL								
	REFORMER WASTE HEAT BOILER	SHELL & TUBE								

FOSTER WHEELER

PRELIMINARY EQUIPMENT LIST

		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	5
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						
LOCATION	THE NETHERLAND						
CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						7
UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	DUTY	SIZE		DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			WIDTH	LENGTH						
		MM Kcal/h	mm	mm	MPa	°C	HEADER/TUBES			
AIR COOLERS										
	RAW HYDROGEN AIR COOLER									
FIRED EQUIPMENT										
	STEAM REFORMER FURNACE	104.88 (**)						(**) Radiant Duty		

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FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	6
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						7
	LOCATION	THE NETHERLAND						
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	HEAD	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			m^3/h	m	MPa	kW	CASING/IMPELLER			
PUMPS										
	BFW CIRCULATION PUMPS	Centrifugal								
	BFW FEED PUMPS	Centrifugal						Two pumps electrical motor driven		

			REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	**PRELIMINARY EQUIPMENT LIST**							
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	7
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						7
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	°C				
MISCELLANEA										
	STEAM VENT SILENCER									
	REFORMER STEAM DESUPERHEATER									
	PREREFORMER STEAM DESUPERHEATER									
	PHOSPHATE PACKAGE									
	EXPORT STEAM DESUPERHEATER									
	OXYGEN SCAVENGER PACKAGE									
	pH CONTROL PACKAGE									
	PSA UNIT		124352	2.58/2.51 (H2 side)	2.8	80				

	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						5
	CASE	CASE 1B: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA WITH H2 RICH FUEL FIRING BURNERS						
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	SIZE ID mm	SIZE L / H mm	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
TOWERS										
	ABSORBER	VERTICAL	3865	20000	28 & F.V	150				
	STRIPPER	VERTICAL	5627	20000	3.5 & F.V	170				
DRUMS										
	FLASH DRUM	HORIZONTAL								
	AMINE SOLUTION TANK	HORIZONTAL								

		PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM	REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG		0	April 2015	GA	GC	GC	2
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE		1	June 2015	GA	GC	GC	OF
FWI CONTRACT:	1BD0840A							
LOCATION	THE NETHERLAND							
CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SY							5
UNIT	CO2 REMOVAL SYSTEM							

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS										
	LEAN/RICH AMINE EXCHANGER	SHELL & TUBE								
	LEAN AMINE TRIM COOLER	SHELL & TUBE								
	STRIPPER CONDENSER									
	STRIPPER REBOILER	KETTLE								
	LEAN AMINE AIR COOLER									

	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
PUMPS										
	BOOSTER PUMPS	CENTRIFUGAL	Power: 586							
	LEAN PUMP	CENTRIFUGAL								
	AMINE SOLUTION PUMP									
	CO2 PUMP (CO2 COMPRESSOR PACKAGE)	CENTRIFUGAL								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	Draft	April 2015	GA	GC	GC	4
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
COMPRESSORS & BLOWERS										
	CO2 COMPRESSORS	CENTRIFUGAL	31357					Brake Power: 3639 kW seven Stages, Pin= 0.29 MPa, Pout= 11 MPa, Tin =49°C, Tout=24°C, MW=42.9, Electical motor to be included Compressor Package includes 3 separators and seven trim coolers		

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	Draft	April 2015	GA	GC	GC	5
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						5
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM SYNGAS WITH H2 RICH SMR FUEL BURNERS						
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
MISCELLANEA										
	DRYER UNIT PACKAGE	MOLSIV	33509					max H2O in outlet stream= 50 ppm v		

FOSTER WHEELER	**PRELIMINARY EQUIPMENT LIST**		**REVISION**	**DATE**	**BY**	**CHKD**	**APP**	**SHEET**
	CLIENT:	IEA GHG	**0**	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						**OF**
	FWI CONTRACT:	1BD0840A						1
	LOCATION	THE NETHERLAND						
	CASE	CASE 1B: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA WITH H2 RICH FUEL FIRING BURNERS						
	UNIT	POWER ISLAND						

ITEM No.	**DESCRIPTION**	**TYPE**	**SIZE**	**PRESSURE INLET/OUTLET**	**DESIGN PRESSURE**	**DESIGN TEMPERATURE**	**MATERIAL**	**REMARKS**		**REV.**
			-	**MPa**	**MPa**	**°C**				
POWER ISLAND										
	STEAM TURBINE AND GENERATOR PACKAGE									
	Including									
	STEAM TURBINE	Backpressure type	8 MWe	4.2 / 0.55				Including: lube oil system; Cooling system; Hydraulic control system; Seal system Drainage system Gland condenser		
	STEAM TURBINE GENERATOR		9.5 MVA					Including relevant auxiliaries		
	STEAM TURBINE BYPASS SYSTEM									

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 1B: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA WITH H2 RICH FUEL FIRING BURNERS						3
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
COOLING WATER SYSTEM										
	SEA WATER PUMPS	Centrifugal	3000 m3/h x 25 m 300 kWe					One operating one spare		
	SEA WATER / CLOSED COOLING WATER EXCHANGER		14.7 MWth							
	CLOSED COOLING WATER PUMPS		1200 m3/h x 25 m 132 kW					One operating one spare		
	CLOSED COOLING WATER CIRCUIT EXPANSION DRUM									
	CORROSION INHIBITOR PACKAGE									
INSTRUMENT / PLANT AIR SYSTEM										
	AIR COMPRESSOR PACKAGE							including: - Air Compressor - Inter/after coolers - KO Drums (including final KO drum)		
	AIR DRYING PACKAGE	Adsorption bed	200 Nm3/h					including: - Adsorbent Bed (with automatic regenaration system) - Regeneration Electrical Heater - Pre Filters - After Filters		
	IA RECEIVER DRUM	vertical								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG						2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						3
	CASE	CASE 1B: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA WITH H2 RICH FUEL FIRING BURNERS						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE -	PRESSURE INLET/OUTLET MPa	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
RAW / DEMI WATER SYSTEM										
	RAW WATER TANK	Fixed roof						12 h storage		
	RAW WATER FILTRATION PACKAGE		85 m3/h							
	POTABLE WATER TANK	Fixed roof						12 h storage		
	POTABLE WATER PACKAGE									
	DEMI WATER PLANT FEED PUMP		85 m3/h x 25 m 11 kW							
	DEMI WATER PACKAGE UNIT		65 m3/h DW production					Including: - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system		
	DEMIWATER PUMPS		65 m3/h x 50 m 18.5 kW							
	DEMIWATER TANK	Fixed roof						12 h storage		

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG						3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 1B: H2 PLANT WITH CO2 CAPTURE FROM SYNGAS USING MDEA WITH H2 RICH FUEL FIRING BURNERS						3
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE -	PRESSURE INLET/OUTLET MPa	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
NITROGEN GENERATION PACKAGE										
	NITROGEN PRODUCTION PACKAGE		500 Nm3/h					Including: - Intake Air Filter - Air Compressor - Air Receiver - Inter/after coolers - KO Drums - Molecular Sieve Water Absorber (Air Dryer) - Chiller Unit - One Expansion Turbine - One Cryogenic Distillation Column - One Main Heat Exchanger		
	LIQUID NITROGEN STORAGE AND VAPORISATION PACKAGE		500 Nm3/h					Including: - Liquid Nitrogen Storage tank - Nitrogen Vaporizer (Air Fin Type) - Nitrogen heater (electrical)		
	GASEOUS NITROGEN BUFFER VESSEL									
FLARE SYSTEM										
	FLARE KO DRUM	Horizontal								
	FLARE PACKAGE		Max relief flowrate 135,000 kg/h; MW:12					Including riser; tip, seal drum		
	FLARE KO DRUM PUMPS	Centrifugal						One operating one spare		
BoP										
	INTERCONNECTING									
	BUILDING (CONTROL ROOM, ELECTRICAL SUBSTATION, LAB)									
	DRAIN SYSTEM									
	FIRE FIGHTING									
	ELECTRICAL SYSTEM							Up to generator terminals		

5. Case 2A

5.1. Basis of Design

This section should be referred to Annex I - Reference Document (Task 2) - for the general plant design criteria and assumptions used in the development of Case 2A (Hydrogen Plant with CO_2 Capture from PSA Tail Gas using MDEA).

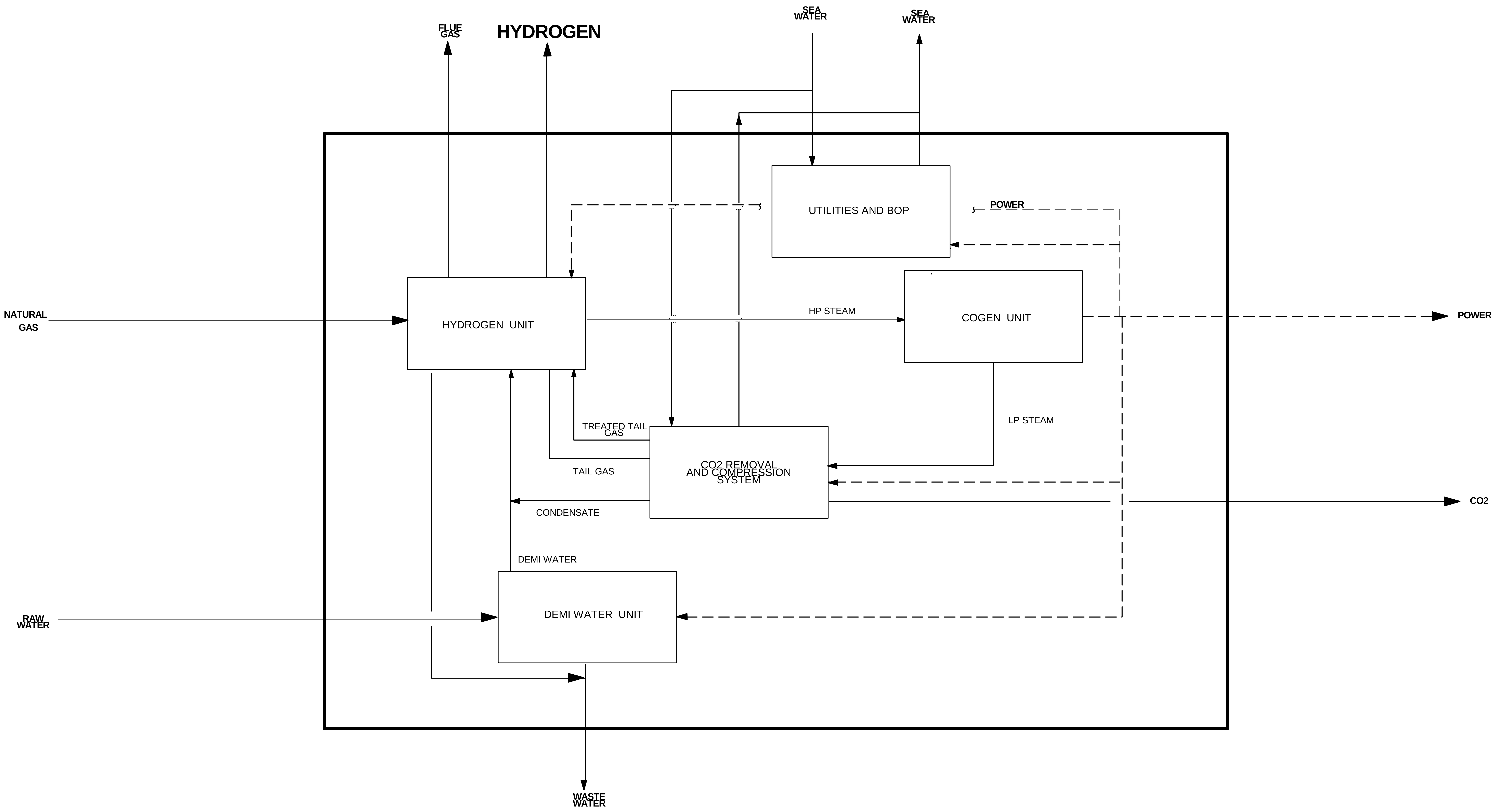
5.2. Units Arrangement

The units included in Case 2A (Hydrogen Plant with CO_2 Capture from PSA Tail Gas using MDEA) are as follows:

- Hydrogen Plant
- Cogen Plant (Power Island)
- CO_2 Capture System (Capture from PSA Tail Gas using MDEA)
- CO_2 compression and dehydration
- Demi-Water Plant
- Utilities and Balance of Plant (BoP), consisting of:
  - Cooling Water System
  - Instrument/Plant Air System
  - Nitrogen Generation Package
  - Flare System
  - Interconnecting
  - Drain System
  - Buildings (Control Room, Laboratories, Electrical Sub-Station).

5.3. Overall Block Flow Diagram

The BFD presented in the next page shows the different unit processes and the relevant inlet/outlet streams included in the Hydrogen Plant for Case 2A (with CO_2 Capture from PSA Tail Gas using MDEA).



Battery Limits Summary								
	Inlet Streams			Outlet Streams				
	Natural Gas From B.L.	Raw Water	Sea Water	Hydrogen	Flue gas to ATM	Power	Captured CO2	Waste Water
	Kg/h	Kg/h	m3/h	Kg/h	Kg/h	kW	kg/h	kg/h
Flow rate	31828	60900	2657	8994	236202	-1070	45563	15800

					FOSTER WHEELER	
1	16/06/2015		GA	GC	UNIT: Overall Block Flow Diagram	
Rev	Date	Comment	By	App.	Case 2A: H2 Plant with CO2 Capture from Tail gas using MDEA	Sheet 01of 01

5.4. Process Description

This section presents the description of the key processes included in the Hydrogen Plant with CO_2 capture from the PSA tail gas using MDEA (Case 2A)

5.4.1. Hydrogen Plant

This section makes reference to the Process Flow Diagram presented in Sheet 1 of Section 5.5.

The Hydrogen Plant for Case 2A is analogous to the Hydrogen Plant reported in Case 1A.

For the description of the different processes relevant to the hydrogen production should be referred to Section 2.4.1 with a caveat that the Tail Gas from the PSA is compressed and fed into the CO_2 capture plant (unlike in the Base Case where PSA Tail Gas is directly sent to the SMR burners).

Additionally, similar to Case 1A, the convective section of the steam reformer has a Steam Generation Coil and Steam Superheater Coil with larger duty (as compared to Base Case) and an additional BFW Pre-heater Coil. This is to provide the extra capacity to generate the steam required by the CO_2 capture plant.

The PSA unit should have the same size and capacity to the PSA unit of the Base Case (as the same amount of Shifted Syngas to be processed – unlike in Case 1A where it has a smaller volume to be processed due to removal of CO_2).

5.4.2. CO_2 Capture Plant (MDEA based Chemical Absorption Technology)

This section makes reference to the Process Flow Diagram presented in Sheets 1 and 2 of Section 5.5.

The Tail Gas from the PSA (containing around 51%mol of CO_2 – wet basis) is initially compressed from ~0.2 MPa to 1 MPa before being fed into the bottom of the Absorption Column where the CO_2 in the Tail Gas is removed by contacting with the lean solvent (flowing in counter-current direction).

The washed tail gas, now containing 3.5%mol of CO_2 (wet basis) leaves the top of the Absorber Column and is pre-heated and expanded to around 0.15 MPa before being fed to the burners of the steam reformer. Whilst, the rich solvent collected at the bottom of the Abosrber Column is fed into the Flash Drum.

The vapour (flashed gas) released from the Flash Drum is sent to the burners as additional fuel to the steam reformer. Whilst, the rich solvent leaving the bottom of the Flash Drum is sent to the Lean/Rich Heat Exchanger to be heated by the incoming stream of hot lean solvent coming from the Stripper's Reboiler. The hot rich solvent leaving the Lean/Rich Heat Exchanger is then fed into the top of the Stripper Column.

In the Stripper Column, the rich solvent flowing down from the top of the column is stripped of its CO_2 by the vapour generated from the Stripper's Reboiler.

The Stripper's Reboiler generates vapour (mainly steam) by re-boiling the lean solvent coming from the Stripper bottom. The vapour is then sent back to the bottom of the Stripper Column and travels upward to strip the CO_2 from the solvent flowing downward.

The Stripper's Reboiler is heated by the LP steam coming from the back pressure steam turbine of the Cogen Plant. The condensate recovered from the reboiler is sent back to the Hydrogen Plant's BFW system.

The overhead gas from the Stripper Column is then sent to the Stripper's Condenser where the steam in the overhead gas are condensed, collected and returned as a reflux to the Stripper Column.

The CO_2 rich gas from the Stripper's Condenser is then sent to the CO_2 compression and dehydration unit.

5.4.3. *CO_2 Compression and Dehydration*

This section makes reference to the Process Flow Diagram presented in Sheet 3 of Section 5.5.

The CO_2 Compression and Dehyrdation Unit for Case 2A has a similar scheme to the CO_2 compressor used in Case 1A. For the description of the CO_2 Compression and Dehydration Unit, this should be referred to Section 3.4.3.

5.4.4. *Cogen Plant (Power Island)*

The Cogen Plant for Case 2A is also based on a back-pressure type steam turbine. For the description of the Cogen Plant, this should be referred to section 3.4.4.

5.4.5. *Demi-Water Plant/Cooling Water System*

The Demi-Water Plant and Cooling Water System for Case 2A has similar scheme used in Case 1A as described in Section 3.4.5.

5.4.6. *Balance of Plant (BoP)*

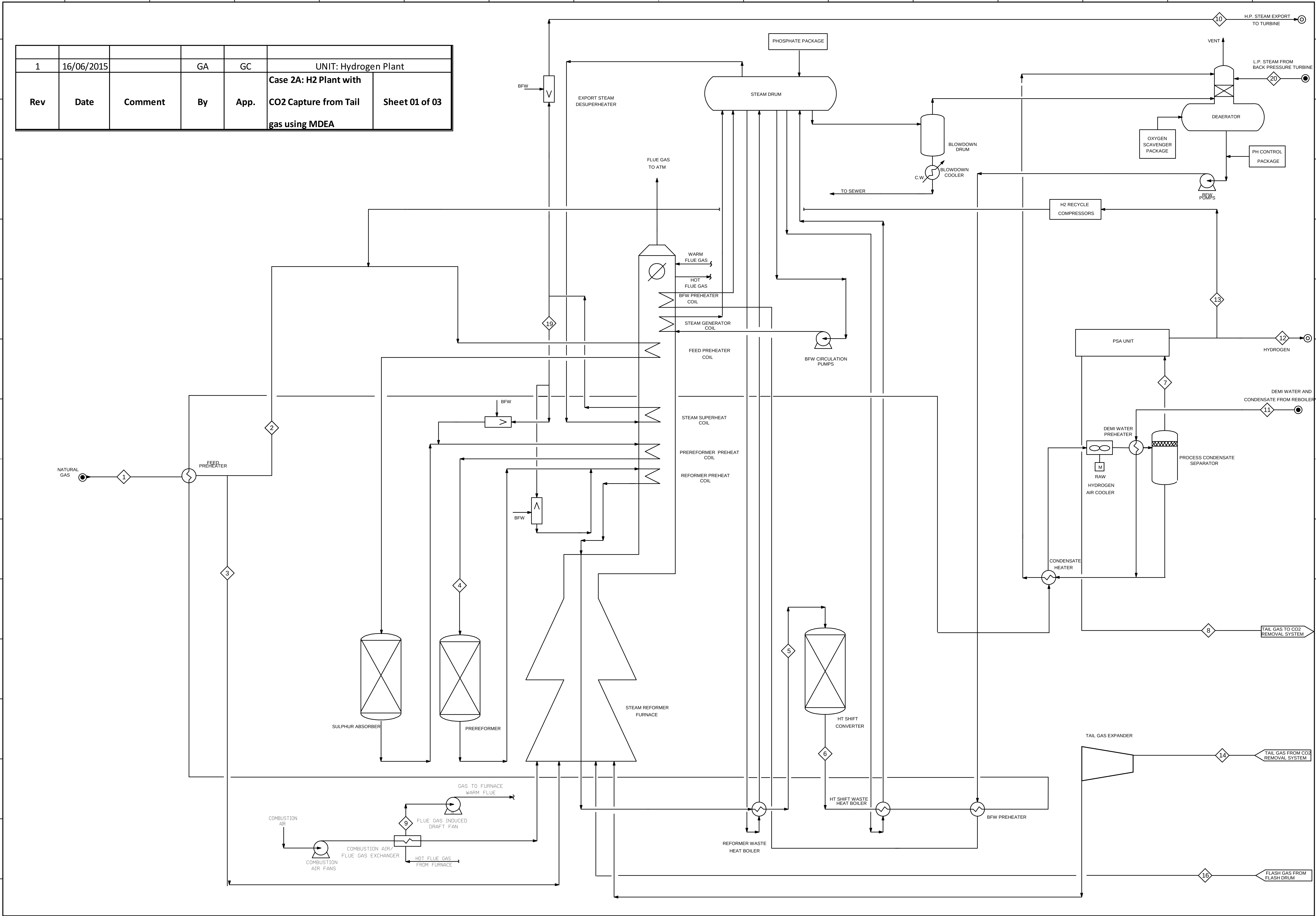
The operation of the whole plant is supported by additional utilities and facilities. These are presented in Section 2.4.4.

5.5. Process Flow Diagram (Hydrogen Plant and CO_2 Capture System)

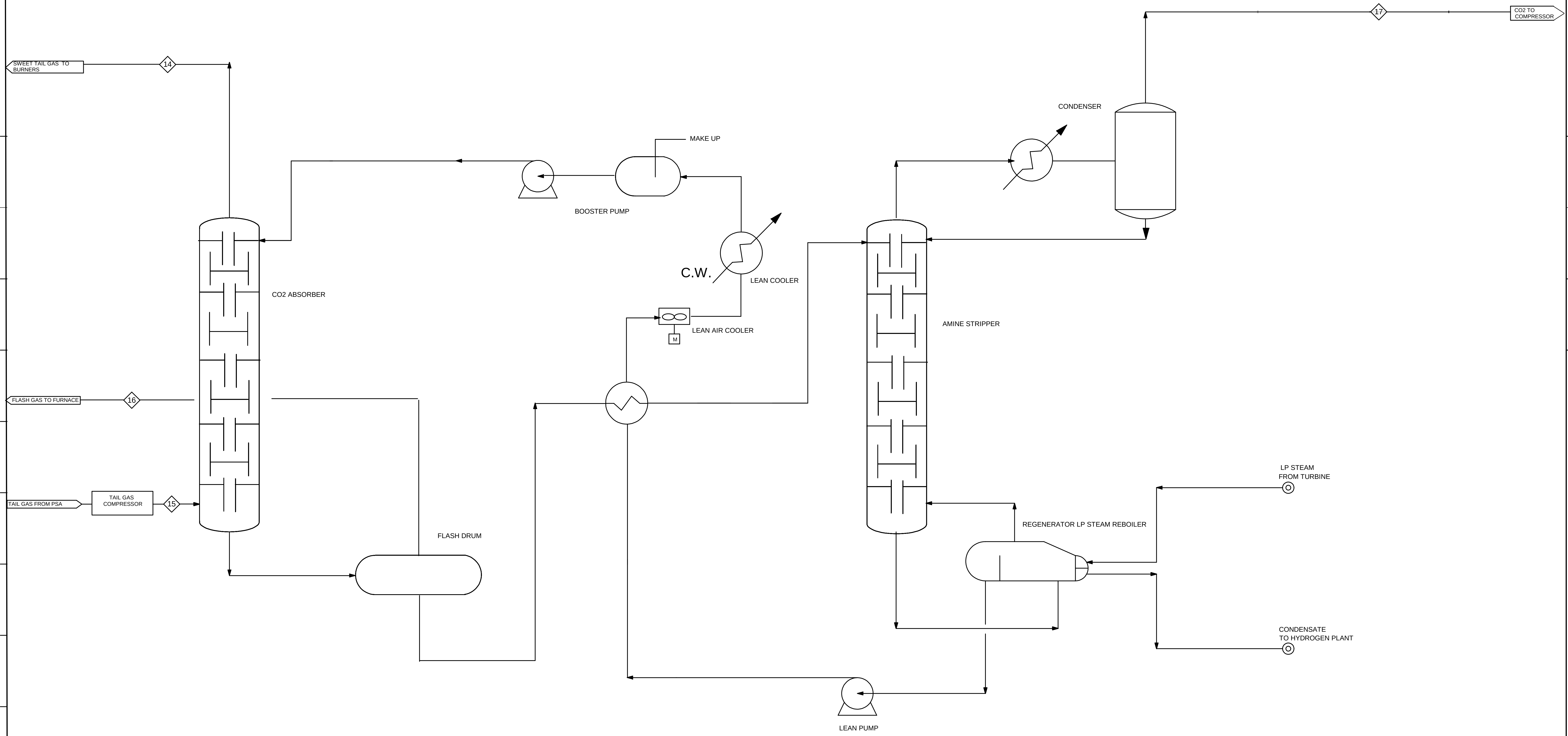
The PFDs enclosed shows the different processes included in the Hydrogen Plant, the CO_2 Capture Plant and the CO_2 Compression and Dehydration Unit.

The processes involving the Hydrogen Plant are described in Section 2.4. The processes involving the CO_2 capture plant and the CO_2 Compression and Dehydration Unit are described in Sections 3.4 and 5.4.2.

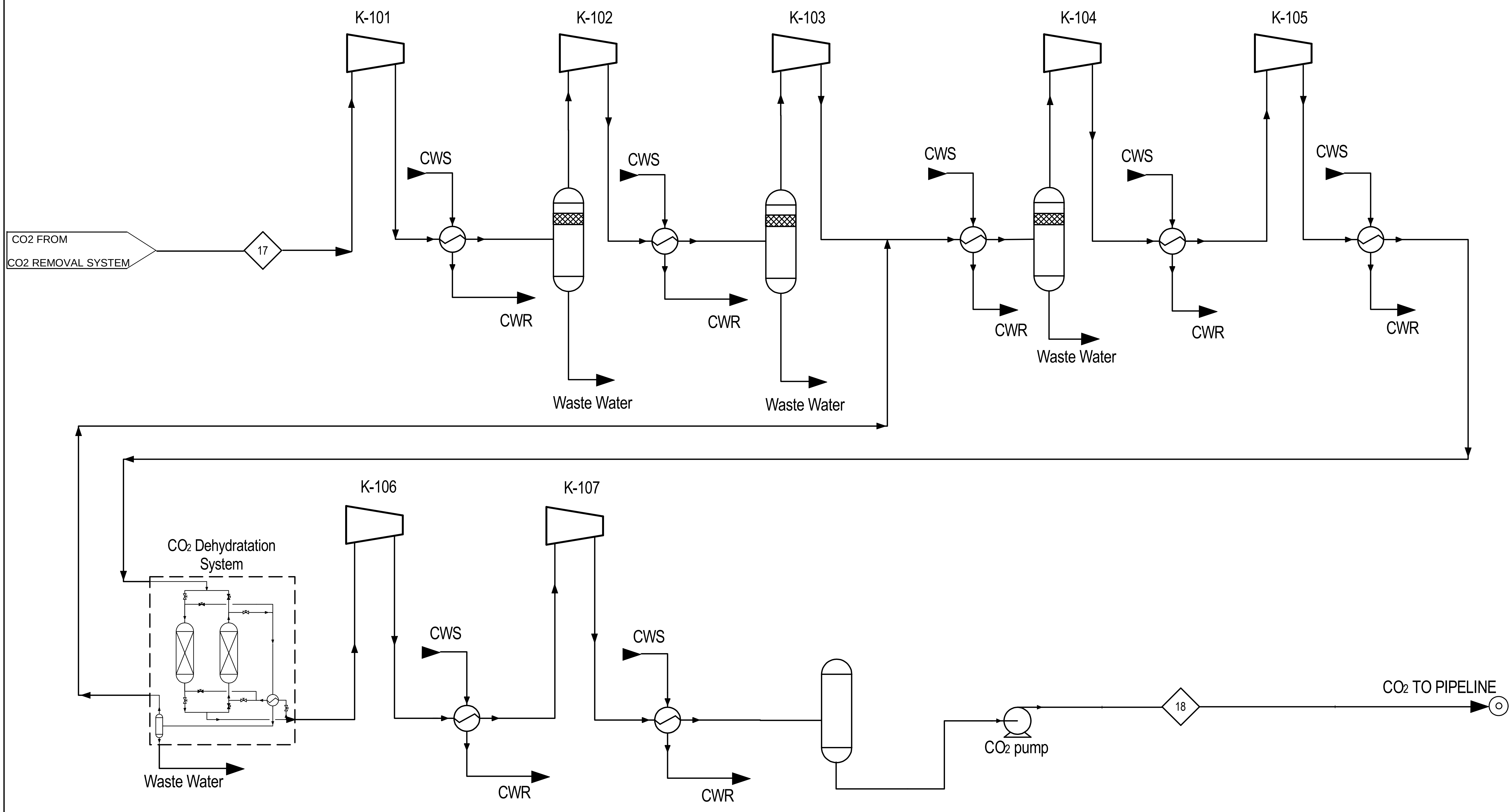
1	16/06/2015		GA	GC	UNIT: Hydrogen Plant
Rev	Date	Comment	By	App.	Case 2A: H2 Plant with CO2 Capture from Tail gas using MDEA — Sheet 01 of 03



1	16/06/2015		GA	GC	UNIT: CO_2 Removal System	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 2A: H_2 Plant with CO_2 Capture from Tail gas using MDEA**	**Sheet 02 of 03**



1	16/06/2015		GA	GC	UNIT: CO2 Compressor	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 2A: H2 Plant with CO2 Capture from Tail gas using MDEA**	**Sheet 03 of 03**



5.6. Heat and Mass Balance

The heat and mass balances reported in this section makes reference to the Process Flow Diagram presented in Section 5.5.

FOSTER WHEELER

HEAT AND MATERIAL BALANCE
Case 2A - Hydrogen Plant with CO2 capture from tail gas using MDEA

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG	**REV**	**DATE**	**BY**	**CHKD**	**APP**
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		1	2	3	4	5	6	7	8	9	10	11	12
Description		Natural Gas From B.L.	Natural Gas feedstock to Hydrogen Plant	Natural Gas fuel to burners	Purified Feedstock to Pre-reformer	HTS Reactor inlet	HTS Reactor Outlet	PSA inlet	PSA Tail gas to tail gas compressor	Flue gas to ATM	HP Steam export	Demi Water (make up) and condensate from Stripper reboiler	Hydrogen to B.L
Temperature	*°C*	9	126	118	500	320	412	35	28	135	394	15	40
Pressure	*MPa*	7.00	3.71	0.50	3.39	2.82	2.77	2.58	0.13	0.02	4.23	0.60	2.50
Molar Flow	*kmol/h*	1766.6	1455.8	310.9	5514.0	8370.3	8370.3	6596.9	2106.3	8488.6	3850.9	6378.0	4461.5
Mass Flow	*kg/h*	31828	26231	5597	98874	101667	101667	69711	60658	236208	69375	114900	8994
Composition													
CO2	*mol/mol*	0.0200	0.0200	0.0200	0.0053	0.0492	0.1283	0.1627	0.5095	0.1036	0.0000	0.0000	0.0000
CO	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.1156	0.0366	0.0464	0.1454	(2)	0.0000	0.0000	0.0000
Hydrogen	*mol/mol*	0.0000	0.0000	0.0000	0.0053	0.5171	0.5961	0.7563	0.2369	0.0000	0.0000	0.0000	0.9999+
Nitrogen	*mol/mol*	0.0089	0.0089	0.0089	0.0023	0.0015	0.0015	0.0020	0.0062	0.6942	0.0000	0.0000	0.0000
Oxygen	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0126	0.0000	0.0000	0.0000
Methane	*mol/mol*	0.8900	0.8900	0.8900	0.2350	0.0238	0.0238	0.0302	0.0945	0.0000	0.0000	0.0000	0.0000
Ethane	*mol/mol*	0.0700	0.0700	0.0700	0.0185	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	*mol/mol*	0.0100	0.0100	0.0100	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	*mol/mol*	0.0010	0.0010	0.0010	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	*mol/mol*	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	*mol/mol*	0.0000	0.0000	0.0000	0.7307	0.2927	0.2137	0.0024	0.0076	0.1894	1.0000	1.0000	0.0000
Contaminants:													
H2S	*ppm v*	(1)											
NOx	*mg/Nm3*									120 max			

Notes:

(1) For feedstock purification section design purposes 5 ppmv of H2S have been assumed in NG to Hydrogen Plant

(2) 30 mg/Nm3 max

FOSTER WHEELER

HEAT AND MATERIAL BALANCE
Case 2A - Hydrogen Plant with CO2 capture from tail gas using MDEA

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG	**REV**	**DATE**	**BY**	**CHKD**	**APP**
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		13	14	15	16	17	18	19	20				
Description		Recycle hydrogen	Sweet Tail gas to burners	Tail gas to CO2 removal system	Flash gas to steam reformer furnace	CO2 from capture plant to Compressor	CO2 to Pipeline	HP steam to process	LP Steam from BP Turbine to Deareator				
Temperature	°C	40	44	28	74	49	24	400	177				
Pressure	MPa	2.51	0.98	1.00	0.45	0.29	11.00	4.29	0.44				
Molar Flow	kmol/h	29.1	1062.9	2106.3	0.8	1080.0	1035.9	4157.2	36.6				
Mass Flow	kg/h	59	14939	60658	20	46362	45570	74892	660				
Composition													
CO2	mol/mol	0.0000	0.0354	0.5095	0.3637	0.9585	0.9994	0.0000	0.0000				
CO	mol/mol	0.0000	0.2878	0.1454	0.1499	0.0001	0.0001	0.0000	0.0000				
Hydrogen	mol/mol	0.9999+	0.4694	0.2369	0.2633	0.0002	0.0002	0.0000	0.0000				
Nitrogen	mol/mol	0.0000	0.0122	0.0062	0.0052	0.0000	0.0000	0.0000	0.0000				
Oxygen	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
Methane	mol/mol	0.0000	0.1870	0.0945	0.1482	0.0002	0.0003	0.0000	0.0000				
Ethane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
Propane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
n-Butane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
n-Pentane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
H2O	mol/mol	0.0000	0.0080	0.0076	0.0697	0.0409	0.0000	1.0000	1.0000				
Contaminants:													
H2S	ppm v												
NOx	mg/Nm3												

Notes:

5.7. Plant Performance Data

The table below summarizes the energy performance and CO_2 emissions relevant to the Hydrogen Plant with CO_2 Capture from PSA Tail Gas using MDEA.

Plant Performance Data Case 2A		
INLET STREAMS		
Natural Gas (as Feedstock)	t/h	26.231
Natural Gas (as Fuel)	t/h	5.597
Natural Gas (Total Consumption)	t/h	31.828
Natural Gas LHV	MJ/kg	46.50
Total Energy Input	MW	411.11
OUTLET STREAMS		
Hydrogen Product to BL	t/h	8.994
	Nm^3/h	100,000
Hydrogen LHV	MJ/kg	119.96
Total Energy in the Product	MW	299.70
POWER BALANCE		
Gross Power Output from the COGEN Plant	MWe	6.900
Hydrogen Plant Power Consumption	MWe	-1.264
COGEN Plant + Utilities + BoP Consumption	MWe	-0.397
CO2 Capture Plant Consumption	MWe	-4.575
Gross Power Output from PSA Tail Gas Expander	MWe	1.140
CO2 Compression and Dehydration Unit	MWe	-2.874
Imported Power from the Grid	MWe	-1.070
SPECIFIC CONSUMPTIONS		
Natural Gas (as Feedstock)	GJ/1000 Nm^3 H_2	12.197
Natural Gas (as Fuel)	GJ/1000 Nm^3 H_2	2.603
Feed + Fuel	GJ/1000 Nm^3 H_2	14.800
SPECIFIC EMISSIONS		
Specific CO2 Emission	t/1000 Nm^3 H_2	0.3870
Specific CO2 Captured	t/1000 Nm^3 H_2	0.4556
Overall CO2 Capture Rate (Case Specific)		54.07%
Overall CO2 Capture Rate (as Compared to Base Case)		52.16%

5.8. Preliminary Utilities Consumption

This section presents the different utilities consumption (usage) of the Hydrogen Plant, Power Island, CO_2 Capture Plant, CO_2 Compression and Dehydration, and others.

ESTIMATED UTILITY CONSUMPTIONS

CUSTOMER NAME:	IEAGHG	**Case 2A - Hydrogen Plant with CO2 capture from tail gas using MDEA**	REV.	REV. 0	REV. 1	REV. 2		SHEET
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE		BY	GA	GA			1
FWI CONTRACT:	1BD0840 A		CHKD	GC	GC			OF
LOCATION:	THE NETHERLAND		DATE	April 2015	June 2015			1

	ELECTRIC POWER		STEAM t / h			EFFLUENT	LOSSES	DMW	RAW WATER	COOLING WATER		SEA WATER		FUEL	INSTR. AIR	Nitrogen
	LOAD BHP	kW	LP	MP	HP	t/h	t/h	t/h	t/h	ΔT (°C)	m³/hr	ΔT (°C)	m³/hr	MMKcal/h	Nm^3/h	Nm^3/h
HYDROGEN PLANT		1,264	0.66	0.00		-1.72	-43.8 (2)	114.9 (1)	0.00	11	11.7			62.2	100	(250)
					-69.4											
CO2 CAPTURE (INCLUDING TAIL GAS COMPRESSOR)		4,575	66.9		1.8			0.66		11	828	7	438			
		-1,140						-68.7								
CO2 COMPRESSION		2,874								11	37	7	840			
POWER ISLAND					67.6											
		-6,900	-67.6													
UTILITIES / BoP		397				-14.1			60.9	11	-877	7	1,379	0.5	100	(250)
								-46.8							-200	(-500)
TOTAL		1,070	0	0	0	-15.8	-43.8	0	60.9	-	0	-	2,657	62.7	0	0

NOTES:

(1) DMW is the sum of DMW plus condensate from CO2 capture unit reboiler

(2) Losses includes water consumed in the reaction and deaerator vent

(3) Water effluent (to be sent to WWT) includes demi plant eluate and steam drum blowdown in the hydrogen plant

5.9. Preliminary Equipment List and Size of Main Components/Packages

This section presents the preliminary list of equipment and main components/packages relevant to the Power Island, CO_2 Capture Plant, CO_2 Compression and Dehydration and BoP of Case 2A.

For the equipment list and size of main components relevant to the Hydrogen Plant should be referred to Section 3.9.

	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 2A: HYDROGEN PLANT WITH CO2 CAPTURE FROM TAIL GAS USING MDEA						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	SIZE ID mm	SIZE L / H mm	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
TOWERS										
	ABSORBER	VERTICAL	3399	20000	28 & F.V	150				
	STRIPPER	VERTICAL	5155	20000	3.5 & F.V	170				
DRUMS										
	FLASH DRUM	HORIZONTAL								
	AMINE SOLUTION TANK	HORIZONTAL								

	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		**REVISION**	**DATE**	**BY**	**CHKD**	**APP**	**SHEET**
FOSTER WHEELER	**CLIENT:**	IEA GHG	**0**	April 2015	GA	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 2A: HYDROGEN PLANT WITH CO2 CAPTURE FROM TAIL GAS USING MDEA						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	**DESCRIPTION**	**TYPE**	**DUTY**	**AREA**	**DESIGN PRESSURE**	**DESIGN TEMPERATURE**	**MATERIAL**	**REMARKS**		**REV.**
					SS / TS	**SS / TS**				
			MM kcal/h	**m^2**	**MPa**	**°C**				
HEAT EXCHANGERS										
	LEAN/RICH AMINE EXCHANGER	SHELL & TUBE								
	LEAN AMINE TRIM COOLER	SHELL & TUBE								
	STRIPPER CONDENSER									
	STRIPPER REBOILER	KETTLE								
	LEAN AIR COOLER									

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST-CO2 REMOVAL SYSTEM		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						5
	CASE	CASE 2A: HYDROGEN PLANT WITH CO2 CAPTURE FROM TAIL GAS USING MDEA						
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
PUMPS										
	BOOSTER PUMPS	CENTRIFUGAL	Power: 181.1							
	LEAN PUMP	CENTRIFUGAL								
	AMINE SOLUTION PUMP									
	CO2 PUMP (CO2 COMPRESSOR PACKAGE)	CENTRIFUGAL								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	4
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE	1	June 2015	GA	GC	GC	OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						5
	CASE	CASE 2A: HYDROGEN PLANT WITH CO2 CAPTURE FROM TAIL GAS USING MDEA						
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
COMPRESSORS & BLOWERS										
	CO2 COMPRESSORS	CENTRIFUGAL	24207					Brake Power: 2809 kW seven Stages, Pin= 0.29 MPa, Pout= 11 MPa, Tin =49°C, Tout=24°C, MW=42.9, Electical motor to be included Compressor Package includes 3 separators and seven trim coolers		
	TAIL GAS COMPRESSOR	INTEGRALLY GEARED	47204					Brake Power: 4280 kW three Stages, Pin= 0.126 MPa, Pout= 1 MPa, Tin =28°C, Tout=28°C, MW=28.8, Electical motor to be included includes three trim coolers		
EXPANDER										
	SWEET TAIL GAS EXPANDER		24,000 Nm3/h					Generator design: 1.2 MWe		

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	5
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 2A: HYDROGEN PLANT WITH CO2 CAPTURE FROM TAIL GAS USING MDEA						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
MISCELLANEA										
	DRYER UNIT PACKAGE	MOLSIV	25664					max H2O in outlet stream= 50 ppm v		

FOSTER WHEELER	**PRELIMINARY EQUIPMENT LIST**	**REVISION**	**DATE**	**BY**	**CHKD**	**APP**	**SHEET**
	CLIENT: IEA GHG	0	April 2015	NF	GC	GC	1
	PROJECT NAME: TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						**OF**
	FWI CONTRACT: 1BD0840A						
	LOCATION THE NETHERLAND						1
	CASE H2 PLANT WITH CO2 CAPTURE-CAPTURE FROM TAIL GAS CASE						
	UNIT POWER ISLAND						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
POWER ISLAND										
	STEAM TURBINE AND GENERATOR PACKAGE									
	Including									
	STEAM TURBINE	Backpressure type	7.5 MWe	4.2 / 0.55				Including: lube oil system; Cooling system; Hydraulic control system; Seal system Drainage system Gland condenser		
	STEAM TURBINE GENERATOR		9.5 MVA					Including relevant auxiliaries		
	STEAM TURBINE BYPASS SYSTEM									

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	H2 PLANT WITH CO2 CAPTURE-CAPTURE FROM TAIL GAS CASE						3
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
COOLING WATER SYSTEM										
	SEA WATER PUMPS	Centrifugal	2800 m3/h x 25 m 280 kWe					One operating one spare		
	SEA WATER / CLOSED COOLING WATER EXCHANGER		11.3 MWth							
	CLOSED COOLING WATER PUMPS		1000 m3/h x 25 m 110 kWe					One operating one spare		
	CLOSED COOLING WATER CIRCUIT EXPANSION DRUM									
	CORROSION INHIBITOR PACKAGE									
INSTRUMENT / PLANT AIR SYSTEM										
	AIR COMPRESSOR PACKAGE							including: - Air Compressor - Inter/after coolers - KO Drums (including final KO drum)		
	AIR DRYING PACKAGE	Adsorption bed	200 Nm3/h					including: - Adsorbent Bed (with automatic regenaration system) - Regeneration Electrical Heater - Pre Filters - After Filters		
	IA RECEIVER DRUM	vertical								

FOSTER WHEELER

PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG						2
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
FWI CONTRACT:	1BD0840A						3
LOCATION	THE NETHERLAND						
CASE	H2 PLANT WITH CO2 CAPTURE-CAPTURE FROM TAIL GAS CASE						
UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
RAW / DEMI WATER SYSTEM										
	RAW WATER TANK	Fixed roof						12 h storage		
	RAW WATER FILTRATION PACKAGE		65 m3/h							
	POTABLE WATER TANK	Fixed roof						12 h storage		
	POTABLE WATER PACKAGE									
	DEMI WATER PLANT FEED PUMP		65 m3/h x 25 m 7.5 kW							
	DEMI WATER PACKAGE UNIT		50 m3/h DW production					Including: - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system		
	DEMIWATER PUMPS		50 m3/h x 50 m 15 kW							
	DEMIWATER TANK	Fixed roof						12 h storage		

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE FOR INDUSTRY						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 2A: HYDROGEN PLANT WITH CO2 CAPTURE FROM TAIL GAS USING MDEA						3
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
NITROGEN GENERATION PACKAGE										
	NITROGEN PRODUCTION PACKAGE		500 Nm3/h					Including: - Intake Air Filter - Air Compressor - Air Receiver - Inter/after coolers - KO Drums - Molecular Sieve Water Absorber (Air Dryer) - Chiller Unit - One Expansion Turbine - One Cryogenic Distillation Column - One Main Heat Exchanger		
	LIQUID NITROGEN STORAGE AND VAPORISATION PACKAGE		500 Nm3/h					Including: - Liquid Nitrogen Storage tank - Nitrogen Vaporizer (Air Fin Type) - Nitrogen heater (electrical)		
	GASEOUS NITROGEN BUFFER VESSEL									
FLARE SYSTEM										
	FLARE KO DRUM	Horizontal								
	FLARE PACKAGE		Max relief flowrate 102,000 kg/h; MW:12					Including riser; tip, seal drum		
	FLARE KO DRUM PUMPS	Centrifugal						One operating one spare		
BoP										
	INTERCONNECTING									
	BUILDING (CONTROL ROOM, ELECTRICAL SUBSTATION, LAB)									
	DRAIN SYSTEM									
	FIRE FIGHTING									
	ELECTRICAL SYSTEM							Up to generator terminals		

6. Case 2B

6.1. Basis of Design

This section should be referred to Annex I - Reference Document (Task 2) - for the general plant design criteria and assumptions used in the development of Case 2B (Hydrogen Plant with CO_2 Capture from PSA Tail Gas using Cryogenic and Membrane Separation Technology).

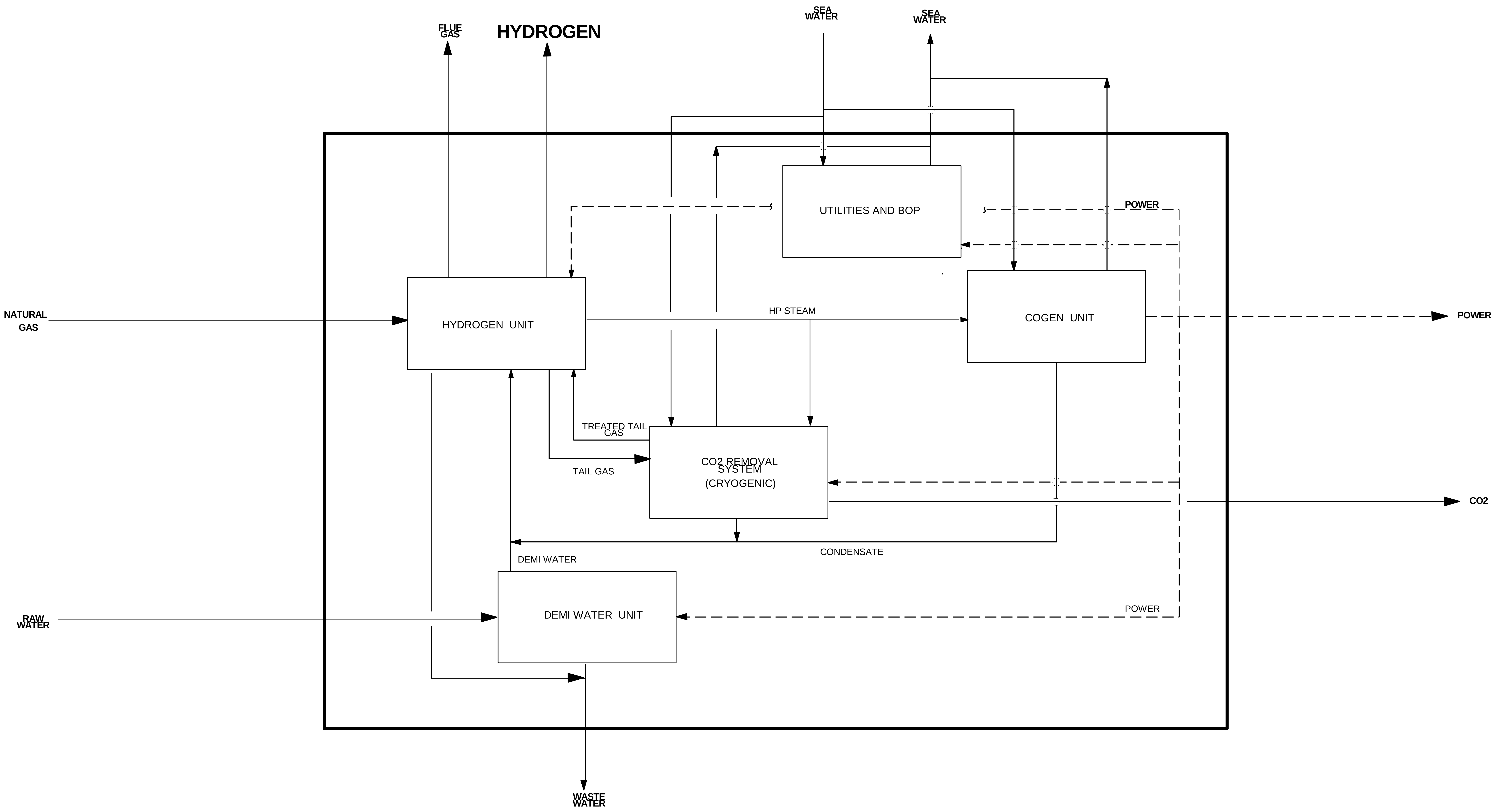
6.2. Units Arrangement

The units included in Case 2B (Hydrogen Plant with CO_2 Capture using Cryogenic and Membrane Technology) are as follows:

- Hydrogen Plant
- Cogen Plant (Power Island)
- CO_2 Capture System (Capture from PSA Tail Gas using Cryogenic and Membrane Separation Technology)
- Demi-Water Plant
- Utilities and Balance of Plant (BoP), consisting of:
  - Cooling Water System
  - Instrument/Plant Air System
  - Nitrogen Generation Package
  - Flare System
  - Interconnecting
  - Drain System
  - Buildings (Control Room, Laboratories, Electrical Sub-Station).

6.3. Overall Block Flow Diagram

The BFD presented in the next page shows the different unit processes and the relevant inlet/outlet streams included in Case 2B (Hydrogen Plant with CO_2 Capture using Cryogenic and Membrane Technology).



Battery Limits Summary								
	Inlet Streams			Outlet Streams				
	Natural Gas From B.L.	Raw Water	Sea Water	Hydrogen	Flue gas to ATM	Power	Equivalent Captured CO2	Waste Water
	Kg/h	Kg/h	m3/h	Kg/h	Kg/h	kW	kg/h	kg/h
Flow rate	30495	59000	4611	8994	214531	284	43012	14800

1	16/06/2015		GA	GC	UNIT: Overall Block Flow Diagram	
Rev	Date	Comment	By	App.	Case 2B: H2 Plant with CO2 Capture using Cryogenic and Membrane Technology	Sheet 01of 01

6.4. Process Description

This paragraph includes the description of the key processes included in the Hydrogen Plant with CO_2 capture from the PSA Tail Gas using Cryogenic and Membrane Separation Technology (Case 2B).

6.4.1. Hydrogen Plant

This section makes reference to the Process Flow Diagram presented in Sheet 1 of Section 6.5.

The Hydrogen Plant of Case 1B is identical to Hydrogen Plant reported in the Base Case except for the PSA Tail Gas being fed into the CO_2 capture plant.

For the description of the different processes relevant to the hydrogen production should be referred to Section 2.4.1 with a caveat that the Tail Gas from the PSA is compressed and fed into the CO_2 capture plant (unlike in the Base Case where PSA Tail Gas is directly sent to the SMR burners).

There will be no changes to the different heat exchanger coils within the convective section of the reformer (unlike in other CO_2 capture cases where additional steam is needed).

There is a possibility to recover more hydrogen from the vent gas coming from the membrane, however this option was not taken up due to the following reasons:

- The available heat in tail gas to burner will decrease if the hydrogen are recovered, therefore implying that additional natural gas will be burnt (as supplementary fuel) and consequently will increase the CO_2 emission.

- This study assumes that the volume of hydrogen production is fixed, therefore to incorporate the additional recovery of hydrogen in the vent will require a change in the design basis for the SMR.

6.4.2. CO_2 Capture Plant (Cryogenic and Membrane Separation Technology)

The purpose of this unit is to compress, dry and cool the Tail Gas from the PSA in order to separate the CO_2 (via partial condensation) from the other gases (CH_4, CO, H_2).

Primarily, the technique used in the Cryogenic or Low Temperature Separation is based on the phase separation principles involving the partial condensation of the CO_2 and separating it from the gas phase in a separator column (i.e. flash or distillation column).

Nowadays, there are several industrial gas companies and equipment suppliers (e.g. Air Liquide, Air Products, Linde, Praxair, Alstom, and Flour) who have developed the cryogenic or low temperature separation technology suitable for separating CO2 from the tail gas of the hydrogen production. In particular, it should be noted that the Port Jerome project is first large scale pilot demonstration of the Air Liquide's Cryocap^{TM} technology to capture CO_2 from the Hydrogen Plants (please refer to Technical Review 3 of this study). Further development and demonstration are still required at commercial scale to fully validate the different processes.

This section makes reference to the Process Flow Diagram presented in Sheet 2 of Section 6.5.

In this study, the CO_2 Purification and Compression Unit (also known as CPU) consists of the following main sections:

- Tail Gas Compressor – to compress the tail gas to the required operating pressure of the cold box.
- Dehydration Unit based on Temperature Swing Adsorption or TSA for dew point control.
- Cold Box based on an auto-refrigeration cycle using 3 flash columns configuration.
- Membrane Separation Unit – for additional CO_2 recovery from the vent of the cold box.
- CO_2 Product Compressor – to compress the CO_2 to its pipeline pressure of 110 Bar.

Tail Gas Compressor

The Tail Gas from PSA (containing around 51%mol of CO_2) is available to the CPU's battery limit at nearly atmospheric pressure. This is mixed with the CO2 rich permeate (coming from the membrane) and compressed to around 2.9 MPa via the Tail Gas Compressor before being fed into the dehydration unit.

The Tail Gas Compressor is an integrally geared centrifugal type compressor driven by an electric motor. This include anti-surge control, vent, inter-stage coolers, knock-out drum and condensate draining facilities as appropriate. Seawater is used as cooling medium.

Dehydration Unit – Based on a TSA system

The compressed tail gas is further dried through a bed of desiccant to lower its dew point to below -55°C.

The dryer is based on Temperature Swing Adsorption or TSA unit which consists of two parallel beds of desiccant (one operating and one re-generating). HP steam from the Hydrogen Plant is used to regenerate the bed.

After the dryer, the dried gas is mixed with the compressed vent gas from the 3rd flash column before being fed into the cold box.

Cold Box

The Cold Box consists of 3 flash columns, 2 brazed heat aluminium heat exchangers (BAHX) and associated JT valves.

The operating pressures and the configuration selected for the cold box are governed by the target purity of the product CO_2 and the specification for the CO_2 recovery rate.

The dried compressed Tail Gas (at 2.8 MPa) is cooled and then fed into the first flash column to separate the partially condensed CO_2 from the gas phase (at -33°C). The liquid CO_2 leaves the bottom of the first flash column and expanded in the JT valve to 1.8 MPa before being warmed up in the first BAHX to around 15°C (The expansion of the liquid CO_2 and the subsequent warming of the CO_2 provides most of the refrigeration to the first BAHX). The vaporised CO_2 is then mixed with the compressed product CO_2 from the 1st stage CO_2 compressor before being fed into the final product CO_2 compressor.

The vent gas from the first flash column (still containing the bulk of the CO_2 at -33°C) is then further cooled and fed into the 2nd flash column to separate the condensed CO_2 (at -54°C). The liquid CO_2 from the 2nd flash column is warmed up in the 2nd BAHX, then expanded in the JT valve to 0.56 MPa before being fed into the 3rd flash column. On the other hand, the vent gas from the 2nd column is warmed up in the two BAHX before being fed into the CO_2 separation membrane.

In the 3rd flash column (at -55°C), the liquid CO_2 leaving the bottom of the column is then vapourised and warmed up in the two BAHX to around 15°C before being fed into the first stage product CO_2 compressor (compressing it to 1.8 MPa).

The vent gas leaving from the top of the 3rd flash column is then warmed up in the 2 BAHX and then re-compressed (from 0.56 MPa to 2.8MPa) before being mixed with the feed gas of the cold box.

It should be noted that the addition of the 3rd column together with the recycling of the CO_2 permeate and the vent gas from the 3rd flash column into the feed gas of the cold box helps in achieving the product CO_2 purity to >99+%.

CO_2 Membrane Separation

The vent gas from the 2nd flash column is typically rich in CO_2 (containing around 55-60% mol. at 2.8 MPa). This is fed into the membrane to produce the CO_2 rich permeate and the non-permeate vent gas.

The CO_2 rich permeate (at nearly atmospheric) is recycled back to the Tail Gas Compressor to enhance the CO_2 recovery rate of the cold box. Whilst the non-permeate (i.e. vent gas) at 2.7MPa is heated by the product CO_2 in the aftercooler of the final CO_2 compressor and HP steam from the Hydrogen Plant before being expanded in the turbo-expander to generate electricity. The expanded vent gas is then sent to the SMR burners as the primary fuel.

Product CO_2 Compressors

The product CO_2 is compressed in two stages. The vaporised CO_2 from the third flash column is compressed from 0.56 to 1.8 MPa in an adiabatic centrifugal compressor. This is then cooled in the aftercooler by the seawater before being mixed with the vaporised from the first flash column. The product CO2 is then further compressed from 1.8 MPa to 11 MPa in the 2nd stage adiabatic compressor. This is then cooled in the aftercooler by the warm vent gas of the 2nd flash column and seawater cooling.

6.4.3. *Cogen Plant (Power Island)*

The COGEN Plant for Case 2B is based on a condensing type steam turbine which is described in Section 2.4.2.

6.4.4. *Demi-Water Plant/Cooling Water System*

The Demi-Water Plant and Cooling Water System for Case 2B has similar scheme used in Base Case as described in Section 2.4.3.

Additionally, once through seawater cooling is mainly used as cooling medium for the inter-coolers of the tail gas compressor, vent gas compressor (from 3rd flash column) and product CO_2 compressors.

6.4.5. *Balance of Plant (BoP)*

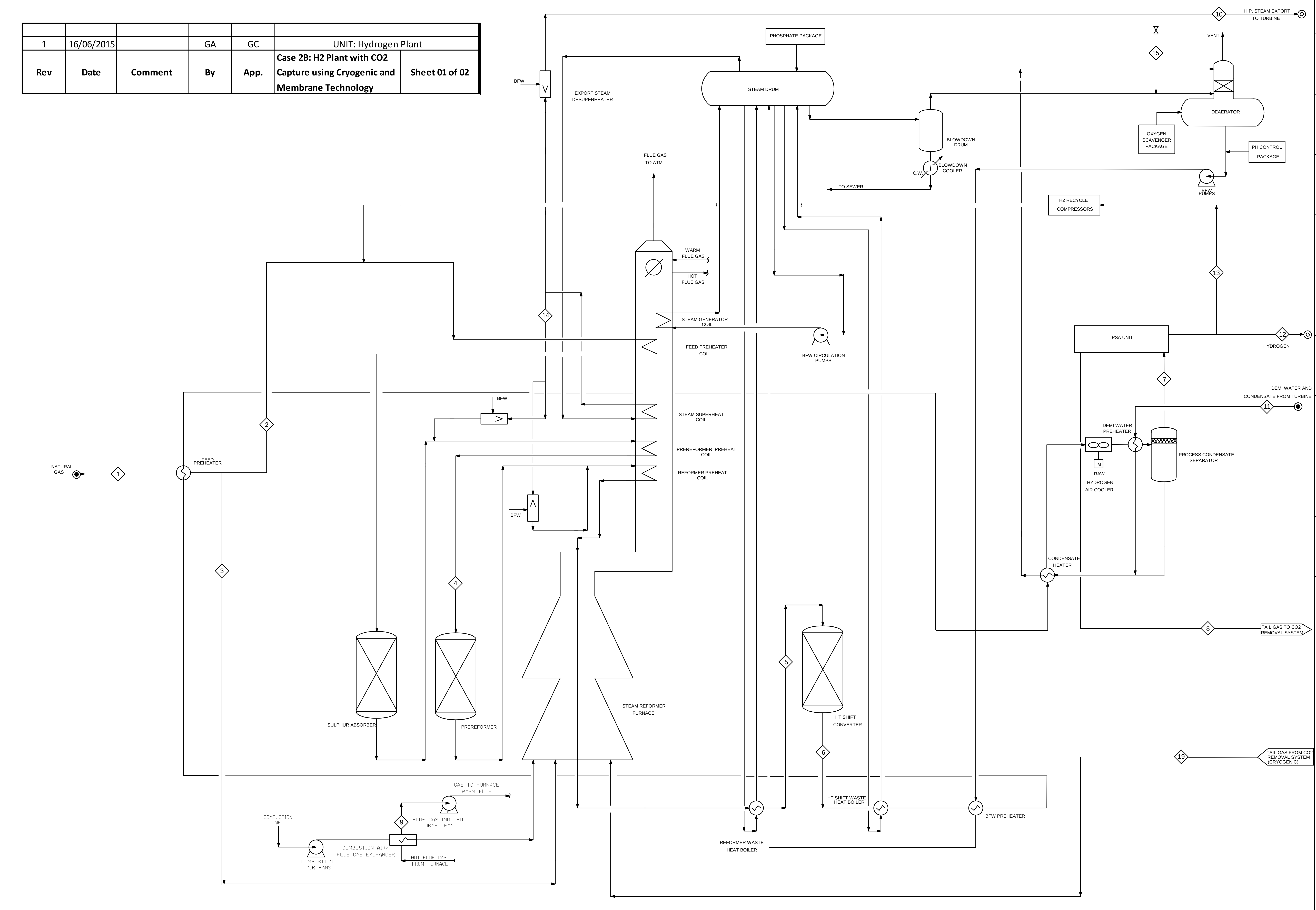
The operation of the whole plant is supported by additional utilities and facilities. These are presented in Section 2.4.4.

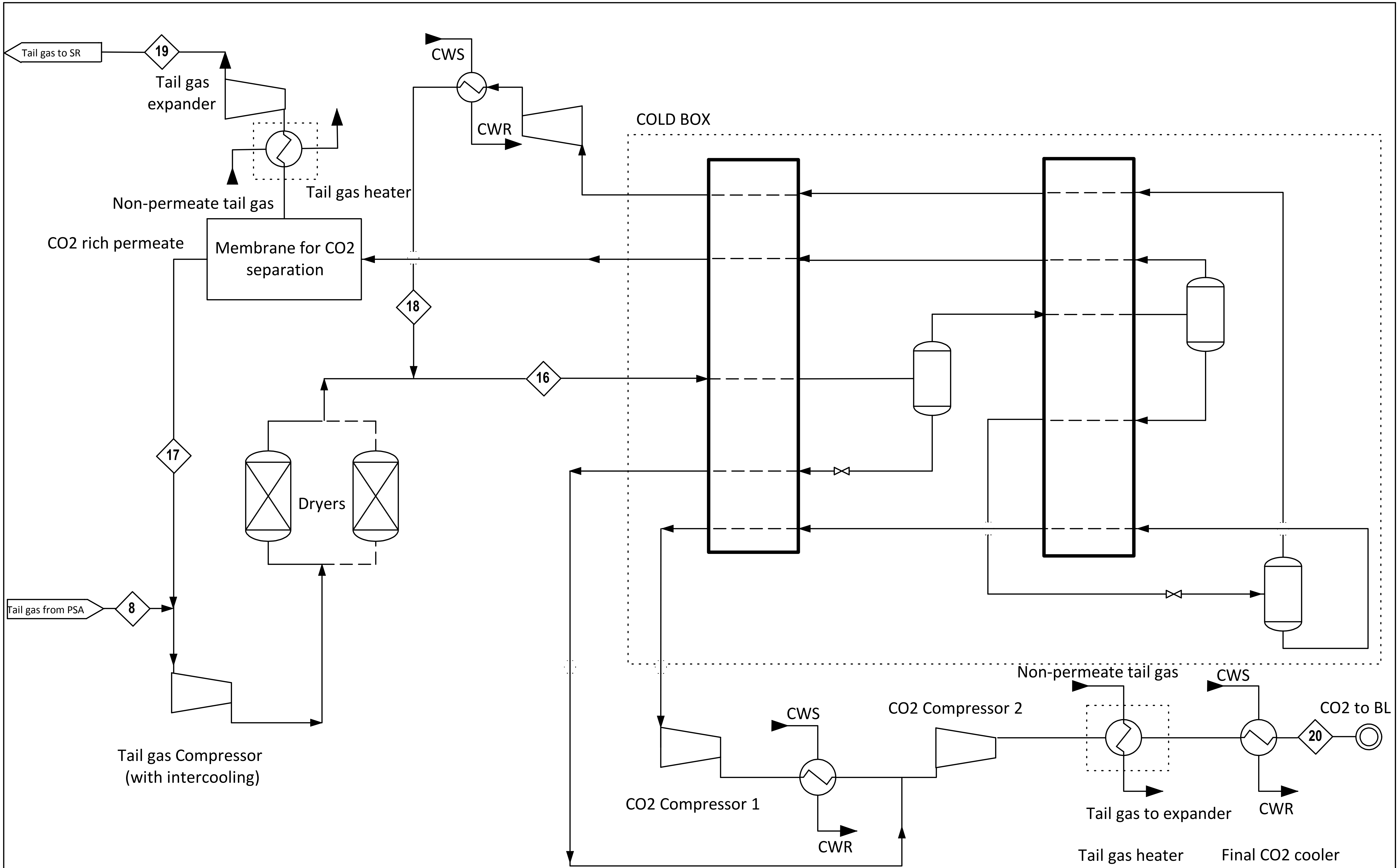
6.5. Process Flow Diagram (Hydrogen Plant and CO_2 Capture System)

The PFDs enclosed shows the different processes included in the Hydrogen Plant, the CO_2 Capture Plant (including CO_2 Compression).

The processes involving the Hydrogen Plant are described in Section 2.4. The processes involving the CO_2 capture plant are described in Sections 6.4.

1	16/06/2015		GA	GC	UNIT: Hydrogen Plant	
Rev	Date	Comment	By	App.	Case 2B: H2 Plant with CO2 Capture using Cryogenic and Membrane Technology	Sheet 01 of 02





1	16/06/2015		NF	GC	UNIT: CO2 Removal System	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 2B: H2 Plant with CO2 Capture using Cryogenic and Membrane Technology**	**Sheet 02 of 02**

6.6. Heat and Mass Balance

The heat and mass balances reported in this section makes reference to the Process Flow Diagram presented in Section 6.5.

FOSTER WHEELER

HEAT AND MATERIAL BALANCE
Case 2B - H2 Plant with CO2 Capture using Cryogenic and Membrane Technology

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG					
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		1	2	3	4	5	6	7	8	9	10	11	12
Description		Natural Gas From B.L.	Natural Gas feedstock to Hydrogen Plant	Natural Gas fuel to burners	Purified Feedstock to Pre-reformer	HTS Reactor Inlet	HTS Reactor Outlet	PSA inlet	PSA Tail gas to CO2 removal System	Flue gas to ATM	HP Steam export	Demi Water (make up) and steam turbine condensate	Hydrogen to B.L
Temperature	°C	9	128	121	500	320	412	35	28	136	395	15	40
Pressure	MPa	7.00	3.71	0.50	3.39	2.80	2.77	2.58	0.13	0.02	4.23	0.60	2.50
Molar Flow	kmol/h	1692.4	1455.8	236.7	5514.0	8370.3	8370.3	6596.9	2106.3	7666.7	2561.7	5070.7	4461.5
Mass Flow	kg/h	30495	26231	4264	98874	101667	101667	69711	60658	214531	46149	91350	8994
Composition													
CO2	mol/mol	0.0200	0.0200	0.0200	0.0053	0.0492	0.1283	0.1627	0.5095	0.1118	0.0000	0.0000	0.0000
CO	mol/mol	0.0000	0.0000	0.0000	0.0000	0.1156	0.0366	0.0464	0.1454	(2)	0.0000	0.0000	0.0000
Hydrogen	mol/mol	0.0000	0.0000	0.0000	0.0053	0.5171	0.5961	0.7563	0.2369	0.0000	0.0000	0.0000	0.9999+
Nitrogen	mol/mol	0.0089	0.0089	0.0089	0.0023	0.0015	0.0015	0.0000	0.0062	0.6875	0.0000	0.0000	0.0000
Oxygen	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0134	0.0000	0.0000	0.0000
Methane	mol/mol	0.8900	0.8900	0.8900	0.2350	0.0238	0.0238	0.0302	0.0945	0.0000	0.0000	0.0000	0.0000
Ethane	mol/mol	0.0700	0.0700	0.0700	0.0185	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	mol/mol	0.0100	0.0100	0.0100	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	mol/mol	0.0010	0.0010	0.0010	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	mol/mol	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	mol/mol	0.0000	0.0000	0.0000	0.7307	0.2927	0.2137	0.0024	0.0076	0.1873	1.0000	1.0000	0.0000
Contaminants:													
H2S	ppm v	(1)											
NOx	mg/Nm3									120 max			

Notes:

(1) For feedstock purification section design purposes 5 ppmv of H2S have been assumed in NG to Hydrogen Plant

(2) 30 mg/Nm3 max

FOSTER WHEELER

HEAT AND MATERIAL BALANCE
Case 2B - H2 Plant with CO2 Capture using Cryogenic and Membrane Technology

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG					
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	CG	CG
FWI CONTRACT:	1BD0840A	1	June 2015	GA	CG	CG
LOCATION:	THE NETHERLAND					

Stream		13	14	15	16	17	18	19	20				
Description		H2 Recycle	HP Steam to process	LP Steam To Deareator	Tail gas to cold box	CO2 rich permeate from membrane	Third flash overhead recycle	Tail gas to Steam Reformer	CO2 to pipeline				
Temperature	°C	40	400	177	22	9	20	29	30				
Pressure	MPa	2.51	4.29	0.44	2.79	0.13	2.80	0.15	11.00				
Molar Flow	kmol/h	29.1	4157.2	30.0	2942.0	667.8	184.7	1112.2	978.0				
Mass Flow	kg/h	59	74892	540	86640	18876	7421	17415	42948				
Composition													
CO2	mol/mol	0.0000	0.0000	0.0000	0.5294	0.4939	0.8401	0.0887	0.9964				
CO	mol/mol	0.0000	0.0000	0.0000	0.1423	0.1525	0.0577	0.2747	0.0007				
Hydrogen	mol/mol	0.9999+	0.0000	0.0000	0.2264	0.2490	0.0053	0.4486	0.0000				
H2S	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
Nitrogen	mol/mol	0.0000	0.0000	0.0000	0.0060	0.0064	0.0027	0.0116	0.0000				
Oxygen	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
Methane	mol/mol	0.0000	0.0000	0.0000	0.0958	0.0981	0.0943	0.1763	0.0029				
Ethane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
Propane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
n-Butane	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
n-Pentane	mol/mol	0.0000	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
H2O	mol/mol	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				
Contaminants:													
H2S	ppm v												
NOx	mg/Nm3												

Notes:

6.7. Plant Performance Data

The table below summarizes the energy performance and CO_2 emissions relevant to the Hydrogen Plant with CO_2 Capture from PSA Tail Gas using Cryogenic and Membrane Separation Technology.

Plant Performance Data Case 2B		
INLET STREAMS		
Natural Gas (as Feedstock)	t/h	26.231
Natural Gas (as Fuel)	t/h	4.264
Natural Gas (Total Consumption)	t/h	30.495
Natural Gas LHV	MJ/kg	46.50
Total Energy Input	MW	393.89
OUTLET STREAMS		
Hydrogen Product to BL	t/h	8.994
	Nm^3/h	100,000
Hydrogen LHV	MJ/kg	119.96
Total Energy in the Product	MW	299.70
POWER BALANCE		
Gross Power Output from the COGEN Plant	MWe	11.000
Hydrogen Plant Power Consumption	MWe	-1.216
COGEN Plant + Utilities + BoP Consumption	MWe	-0.511
CO2 Capture Plant Consumption	MWe	-10.919
Gross Power Output from Vent Gas Expander	MWe	1.930
CO2 Compression and Dehydration Unit	MWe	(see Note 1)
Excess Power to the Grid	MWe	0.284
SPECIFIC CONSUMPTIONS		
Natural Gas (as Feedstock)	GJ/1000 Nm^3 H_2	12.197
Natural Gas (as Fuel)	GJ/1000 Nm^3 H_2	1.983
Feed + Fuel	GJ/1000 Nm^3 H_2	14.180
SPECIFIC EMISSIONS		
Specific CO2 Emission	t/1000 Nm^3 H_2	0.3772
Specific CO2 Captured	t/1000 Nm^3 H_2	0.4289
Overall CO2 Capture Rate (Case Specific)		53.28%
Overall CO2 Capture Rate (as Compared to Base Case)		53.38%

*Note 1: power consumption of the CO_2 compression and dehydration are included in the CO_2 capture plant.

6.8. Preliminary Utilities Consumption

This section presents the different utilities consumption (usage) of the Hydrogen Plant, Power Island, CO_2 Capture Plant, and others.

FOSTER WHEELER

ESTIMATED UTILITY CONSUMPTIONS

CUSTOMER NAME:	IEAGHG	Case 2B - H2 Plant with CO2 Capture using Cryogenic and Membrane Technology	REV.	REV. 0	REV. 1	REV. 2				SHEET
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE		BY	GA						1
FWI CONTRACT:	1BD0840 A		CHKD	GC						OF
LOCATION:	THE NETHERLAND		DATE	April 2015						1

	ELECTRIC POWER		STEAM t / h			EFFLUENT	LOSSES	DMW	RAW WATER	COOLING WATER		SEA WATER		FUEL	INSTR. AIR	Nitrogen
	LOAD BHP	kW	LP	MP	HP	t/h	t/h	t/h	t/h	ΔT (°C)	m³/hr	ΔT (°C)	m³/hr	MMKcal/h	Nm^3/h	Nm^3/h
HYDROGEN PLANT		1,216	0.54	0.00		-1.14	-44.2 (2)	91.5 (1)	0.00	11	9.70			48.2	100	(250)
					-46.1											
CO2 CAPTURE		10,919			1.3			-1.3		11	139.0	7	1650			
		-1,930														
POWER ISLAND		19			44.9							7	3195			
		-11,000						-44.9								
UTILITIES / BoP		492				-13.6			59.0	11	-148.7	7	-234	0.5	100	(250)
								-45.4							-200	(-500)
TOTAL		-284	1	0	0	-14.8	-44.2	0	59.0	-	0	-	4,611	48.7	0	0

NOTES:

(1) DMW is the sum of DMW plus condensate from turbine

(2) Losses includes water consumed in the reaction and deaerator vent

(3) Water effluent (to be sent to WWT) includes demi plant eluate and steam drum blowdown in the hydrogen plant

6.9. Preliminary Equipment List and Size of Main Components/Packages

This section presents the preliminary list of equipment and main components/packages relevant to the Power Island, CO_2 Capture Plant, and BoP of Case 2B.

For the equipment list and size of main components relevant to the Hydrogen Plant should be referred to Section 2.9.

PRELIMINARY EQUIPMENT LIST

		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	**0**	April 2015	NF	CG	CG	1
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
FWI CONTRACT:	1BD0840A						2
LOCATION	THE NETHERLAND						
CASE	CASE 2B - H2 PLANT WITH CO2 CAPTURE USING CRYOGENIC AND MEMBRANE TECHNOLOGY						
UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS	REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER		
COMPRESSORS									
	TAIL GAS COMPRESSOR	CENTRIFUGAL	65,000					Brake Power: 8,650 kW Five stages centrifugal compressor Electrical driven Pin= 0.1 MPa, Pout= 2.9 MPa, Including: 5 condensate separators 4 intercoolers + 1 aftercooler	
	OVERHEAD FLASH RECYCLE COMPRESSOR	CENTRIFUGAL						Brake Power: 250 kW Three stages centrifugal compressor Electrical driven Pin= 0.54 MPa, Pout= 2.8 MPa, Including: 1 intercooler + 1 aftercooler	
	CO2 COMPRESSORS	CENTRIFUGAL	22,000					Brake Power: 2,500 kW Three stages centrifugal compressor Electrical driven Pin= 0.54 MPa, Pout= 11.0 MPa, Including: 2 intercoolers + 2 aftercooler (non-condensable heater + final cooler)	
EXPANDER									
	NON PERMEATE GAS EXPANDER		25,000					Generator design: 2 MWe	

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST	REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT: IEA GHG	0	April 2015	NF	CG	CG	2
	PROJECT NAME: TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT: 1BD0840A						2
	LOCATION: THE NETHERLAND						
	CASE: CASE 2B - H2 PLANT WITH CO2 CAPTURE USING CRYOGENIC AND MEMBRANE TECHNOLOGY						
	UNIT: CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS	REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER		
MISCELLANEA									
	DESSICANT PACKAGE	TSA	68,750	2.9				Oulet stream dew point= -55°C@29 bar	
	COLD BOX PACKAGE		Feed flowrate: 66,000 Nm3/h					Including: - multi-stream plate-fin aluminium heat exchanger - three (3) flash separators	
	CO2 MEMBRANE		Feed flowrate: 40,000 Nm3/h						

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 2B - H2 PLANT WITH CO2 CAPTURE USING CRYOGENIC AND MEMBRANE TECHNOLOGY						1
	UNIT	POWER ISLAND						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
POWER ISLAND										
	STEAM TURBINE AND GENERATOR PACKAGE									
	Including									
	STEAM TURBINE	Condensing type	12 MWe					Including: lube oil system; Cooling system; Hydraulic control system; Seal system Drainage system Gland condenser		
	STEAM TURBINE GENERATOR		15 MVA					Including relevant auxiliaries		
	STEAM TURBINE BYPASS SYSTEM									
	STEAM CONDENSER PACKAGE		24 x 10^6 kcal/h	Condensing pressure: 8 kPa				Including: Condenser hotwell Ejector Start-up Ejector		
	CONDENSATE PUMP	Centrifugal	60 m3/h x 80 m 22 kW					One operating one spare		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 2B - H2 PLANT WITH CO2 CAPTURE USING CRYOGENIC AND MEMBRANE TECHNOLOGY						3
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
COOLING WATER SYSTEM										
	SEA WATER PUMPS	Centrifugal	4850 m3/h x 25 m 475 kWe					One operating one spare		
	SEA WATER / CLOSED COOLING WATER EXCHANGER		1.4 MWth							
	CLOSED COOLING WATER PUMPS							One operating one spare		
	CLOSED COOLING WATER CIRCUIT EXPANSION DRUM									
	CORROSION INHIBITOR PACKAGE									
INSTRUMENT / PLANT AIR SYSTEM										
	AIR COMPRESSOR PACKAGE							including: - Air Compressor - Inter/after coolers - KO Drums (including final KO drum)		
	AIR DRYING PACKAGE	Adsorption bed	200 Nm3/h					including: - Adsorbent Bed (with automatic regenaration system) - Regeneration Electrical Heater - Pre Filters - After Filters		
	IA RECEIVER DRUM	vertical								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						3
	CASE	CASE 2B - H2 PLANT WITH CO2 CAPTURE USING CRYOGENIC AND MEMBRANE TECHNOLOGY						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
RAW / DEMI WATER SYSTEM										
	RAW WATER TANK	Fixed roof						12 h storage		
	RAW WATER FILTRATION PACKAGE		65 m3/h							
	POTABLE WATER TANK	Fixed roof						12 h storage		
	POTABLE WATER PACKAGE									
	DEMI WATER PLANT FEED PUMPS		65 m3/h x 25 m 7.5 kW					One operating, one spare		
	DEMI WATER PACKAGE UNIT		50 m3/h DW production					Including: - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system		
	DEMIWATER PUMPS		50 m3/h x 50 m 15 kW					One operating, one spare		
	DEMIWATER TANK	Fixed roof						12 h storage		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	NF	CG	CG	3
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						3
	LOCATION	THE NETHERLAND						
	CASE	CASE 2B - H2 PLANT WITH CO2 CAPTURE USING CRYOGENIC AND MEMBRANE TECHNOLOGY						
	UNIT	UTILITIES AND BOP						

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
NITROGEN GENERATION PACKAGE										
	NITROGEN PRODUCTION PACKAGE		500 Nm3/h					Including: - Intake Air Filter - Air Compressor - Air Receiver - Inter/after coolers - KO Drums - Molecular Sieve Water Absorber (Air Dryer) - Chiller Unit - One Expansion Turbine - One Cryogenic Distillation Column - One Main Heat Exchanger		
	LIQUID NITROGEN STORAGE AND VAPORISATION PACKAGE		500 Nm3/h					Including: - Liquid Nitrogen Storage tank - Nitrogen Vaporizer (Air Fin Type) - Nitrogen heater (electrical)		
	GASEOUS NITROGEN BUFFER VESSEL									
FLARE SYSTEM										
	FLARE KO DRUM	Horizontal								
	FLARE PACKAGE		Max relief flowrate 102,000 kg/h; MW:12					Including riser; tip, seal drum		
	FLARE KO DRUM PUMPS	Centrifugal						One operating one spare		
BoP										
	INTERCONNECTING									
	BUILDING (CONTROL ROOM, ELECTRICAL SUBSTATION, LAB)									
	DRAIN SYSTEM									
	FIRE FIGHTING									
	ELECTRICAL SYSTEM							Up to generator terminals		

7. Case 3

7.1. Basis of Design

This section should be referred to Annex I - Reference Document (Task 2) - for the general plant design criteria and assumptions used in the development of Case 3 (Hydrogen Plant with CO_2 Capture from the Flue Gas of the SMR using MEA).

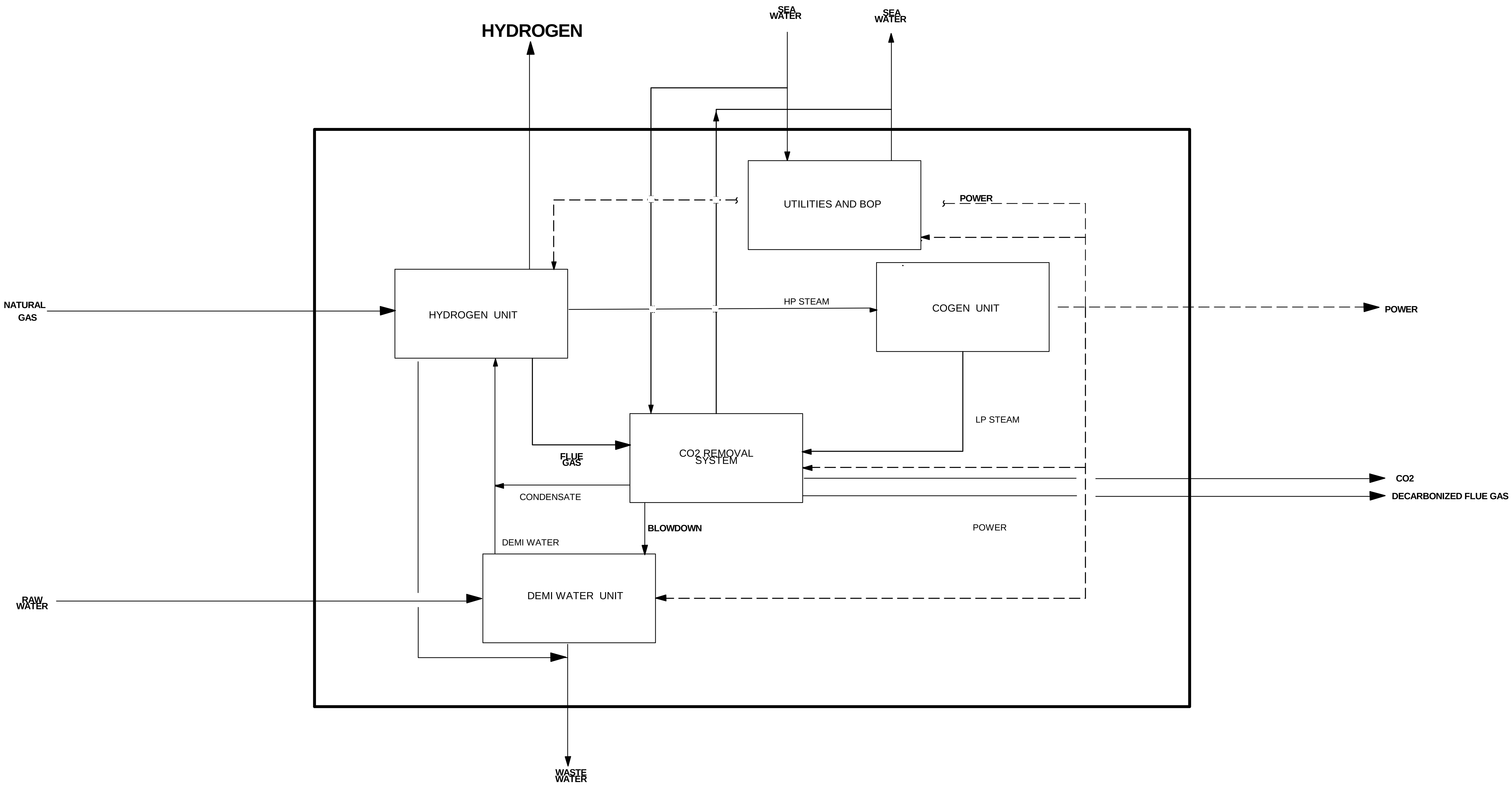
7.2. Units Arrangement

The units included in Case 3 (Hydrogen Plant with CO_2 Capture from the SMR Flue Gas using MEA) are as follows:

- Hydrogen Plant
- Cogen Plant (Power Island)
- CO_2 Capture System (Capture from the SMR's Flue Gas using MEA)
- CO_2 Compression and Dehydration
- Demi-Water Plant
- Utilities and Balance of Plant (BoP), consisting of:
  - Cooling Water System
  - Instrument/Plant Air System
  - Nitrogen Generation Package
  - Flare System
  - Interconnecting
  - Drain System
  - Buildings (Control Room, Laboratories, Electrical Sub-Station).

7.3. Overall Block Flow Diagram

The BFD presented in the next page shows the different unit processes and the relevant inlet/outlet streams included in Case 3 (Hydrogen Plant with CO_2 Capture from SMR's flue gas using MEA).



Battery Limits Summary								
	Inlet Streams			Outlet Streams				
	Natural Gas From B.L.	Raw Water	Sea Water	Hydrogen	Decarbonized Flue gas to ATM	Power	Captured CO2	Waste Water
	Kg/h	Kg/h	m3/h	Kg/h	Kg/h	kW	kg/h	kg/h
Flow rate	33579	42100	10589	8994	211995	427	80048	16500

1	16/06/2015		GA	GC	UNIT: Overall Block Flow Diagram
Rev	Date	Comment	By	App.	Case 3 - Hydrogen Plant with CO2 capture from flue gas using MEA — Sheet 01of 01

7.4. Process Description

This section presents the description of the key processes included in the Hydrogen Plant with CO_2 Capture from the SMR's Flue Gas using MEA (Case 3).

7.4.1. Hydrogen Plant

This section makes reference to the Process Flow Diagram presented in Sheet 1 of Section 7.5.

The Hydrogen Plant used in Case 3 is analogous to the Hydrogen Plant reported in the Base Case. For the process description relevant to the hydrogen production is presented in Section 2.4.1.

There are a couple of differences between the Hydrogen Plant of Case 3 and the Hydrogen Plant reported in Base Case. These include:

- Higher Natural Gas consumption (an increase of 9.9%$_{wt.}$ as compared to the Base Case) due to the additional supplementary fuel needed to produce the steam required by the CO_2 capture plant.
- The SMR's flue gas after pre-heating of the combustion air is sent to the battery limit of the CO_2 capture plant to pre-heat the out-going vent gas from the CO_2 absorber.
- The convective section of the steam reformer includes a steam generation coil and a steam superheater coil with larger duty as compared to the Base Case and an additional BFW pre-heating coil (this has similar configuration to the Hydrogen Plant reported in Case 1A). This is to provide the additional steam generation capacity required to meet the additional steam demand used in the solvent regeneration of the CO_2 capture plant.

7.4.2. CO_2 Capture Plant (MEA based Chemical Absorption Technology)

This section makes reference to the Process Flow Diagram presented in Sheet 2 of Section 7.5.

The CO_2 Capture Plant is based on chemical absorption technology using MEA as solvent with a variant of a split flow configuration employed.

The capture plant mainly consist of gas-gas heater, quench scrubber, absorber and water wash column (with associated inter-coolers), lean/rich amine heat exchangers, flash drum, stripper column (with associated condenser and reboiler), various trim coolers, filters and pumps.

The SMR's flue gas coming from the Combustion Air/Flue Gas Heat Exchanger, at a temperature of about 135°C, is cooled in the gas-gas heater by the vent gas (or de-carbonised flue gas coming from the absorber column). The vent gas is then discharged to the atmosphere in the stack at about 90ºC.

The cooled flue gas is then fed into a quench scrubber/direct contact cooler for further cooling and desulphurisation by washing with a solution of caustic soda or sodium bicarbonate. This reduces the SOx in the flue gas to below 1 ppm level (in order to minimise any degradation of the solvent).

The majority of the sour water collected from the bottom of the direct contact cooler is cooled and recirculated to the top of the scrubber. A bleed is taken and sent to the Waste Water Treatment Unit of the Raw Water System.

The cooled flue gas is blown into the Absorber Column where the CO_2 is absorbed by contacting with a semi-lean MEA solution in the first packed bed and then by the lean (fully generated) MEA solution in the second pack bed.

The treated flue gas is then washed in the water wash column before being sent to the gas-gas heater (i.e. to minimise the carryover of amine and degraded products). The water used in the water wash column is cooled by the pump-around coolers which helps remove the heat of reaction during the CO_2 absorption with MEA.

The rich amine is pumped from the bottom of the Absorber Column and is split into two streams. The first stream is heated in the Cross Heat Exchanger by the hot lean amine coming from the Stripper's Bottom (Reboiler) and this is fed into the top of Stripper Column. The second stream is initially heated by the semi-lean amine (coming from the bottom of the Flash Column) in the Semi-Lean Solvent Cooler and further heated by the lean amine in the Flash Pre-heater before being fed into the Flash Column where this produces a vapour or gas phase which is sent to the stripper column, and the liquid phase which constitutes the semi-lean amine.

The lean amine coming from the Flash Pre-heater is further cooled in the Lean Solvent Cooler before being introduced into the top of the Absorber Column. On the other hand, the semi-lean amine from the Semi-Lean Solvent Cooler is introduced in the middle of the Absorber Column.

The heated rich MEA solvent is regenerated in the stripping column, which consists of a stripping and rectification section. The column traffic in the lower section is mainly driven by the vertical thermosiphon reboilers situated at the bottom of the stripping column. The reboilers are heated by the LP steam coming from the Back Pressure Steam Turbine of the Cogen Plant. The condensate recovered from the reboiler is sent back to the Hydrogen Plant's BFW system.

The overhead vapour from the Stripper Column is then sent to the Stripper's Condenser where the steam in the overhead gas are condensed, collected and returned as a reflux to the Stripper Column and with some excess condensate pumped to storage.

The CO_2 rich gas from the Stripper's Condenser is then sent to the CO_2 compression and dehydration unit.

Additionally, a portion of the lean amine is periodically withdrawn and sent to the Reclaimer to remove the heat stable salts (which are formed from the reaction of the MEA with the impurities present in the flue gas).

The Reclaimer is a kettle type heat exchanger similar to the reboiler. The operation of the Reclaimer is a batch process. Normally, a small amount of caustic soda is initially injected as a neutralising agent to precipitate the heat stable salts. The vapour gathered from the Reclaimer is sent back to the bottom of the column. The remaining heavy residue collected after the reclaiming process is pumped away for disposal. Occasionally, fresh MEA from the amine storage tank is added to maintain the liquid level in the Reclaimer. The LP steam coming from the Back Pressure Steam Turbine is also used to re-boil the lean amine. The condensate collected are sent back to the Hydrogen Plant's Deaerator.

7.4.3. CO_2 Compression and Dehydration

This section makes reference to the Process Flow Diagram presented in Sheet 3 of Section 7.5.

The CO_2 Compression and Dehydration unit includes the Compressor, Knock-out Drums, Inter-Stage Coolers, Dehydration Unit and Liquid CO_2 pump.

The overhead gas (mainly CO_2) leaving the Stripper's Condenser is compressed to a pressure of 8 MPa by a single train eight-stage centrifugal compressor. The CO_2 compressor is an integrally geared and electrically driven machine which is equipped with anti-surge control, vent, inter-stage coolers and knock-out drums in between stages and condensate draining facilities as required.

There is one Inter-stage Coolers installed after each compression stage. Seawater is used as cooling medium. The condensed water in the inter-cooler is separated from the gas in the knock-out drum (this is installed after each inter-coolers up to the fifth stage). The gas leaving the sixth inter-stage cooler is then fed into the dehydration unit.

The dehydration unit is based on a molecular sieve / activated alumina adsorbent dryer. The dryer is designed to operate and produce CO_2 product with a dew point temperature of -40°C. The dryer consists of two bed of adsorbents for every train of compressor. During normal operation, one bed is operational and the other bed (saturated with water) is regenerated. The bed are regenerated by the dry product gas (ca. 10% taken from the dried product gas after the dryer). The regeneration gas (now saturated with water) is recycled back after the third stage compression.

The final two compression stages downstream of the dehydration unit increases the CO_2 pressure to 8 MPa. After the being cooled, the dried compressed CO_2 in dense phase is finally pumped and delivered the to the battery limits of the plant at pipeline pressure of 11 MPa.

7.4.4. Cogen Plant (Power Island)

The Cogen Plant used in Case 3 has a similar scheme reported in Case 1A as described in Section 3.4.4.

The LP steam from the Back Pressure Steam Turbine is sent to the Stripper's Reboiler and Reclaimer with a small part being fed to the deaerator (as supplementary steam for stripping).

7.4.5. Demi-Water Plant/Cooling Water System

The Demi-Water Plant and Cooling Water System for Case 3 has similar scheme used in Case 1A as described in Section 3.4.5.

7.4.6. Balance of Plant (BoP)

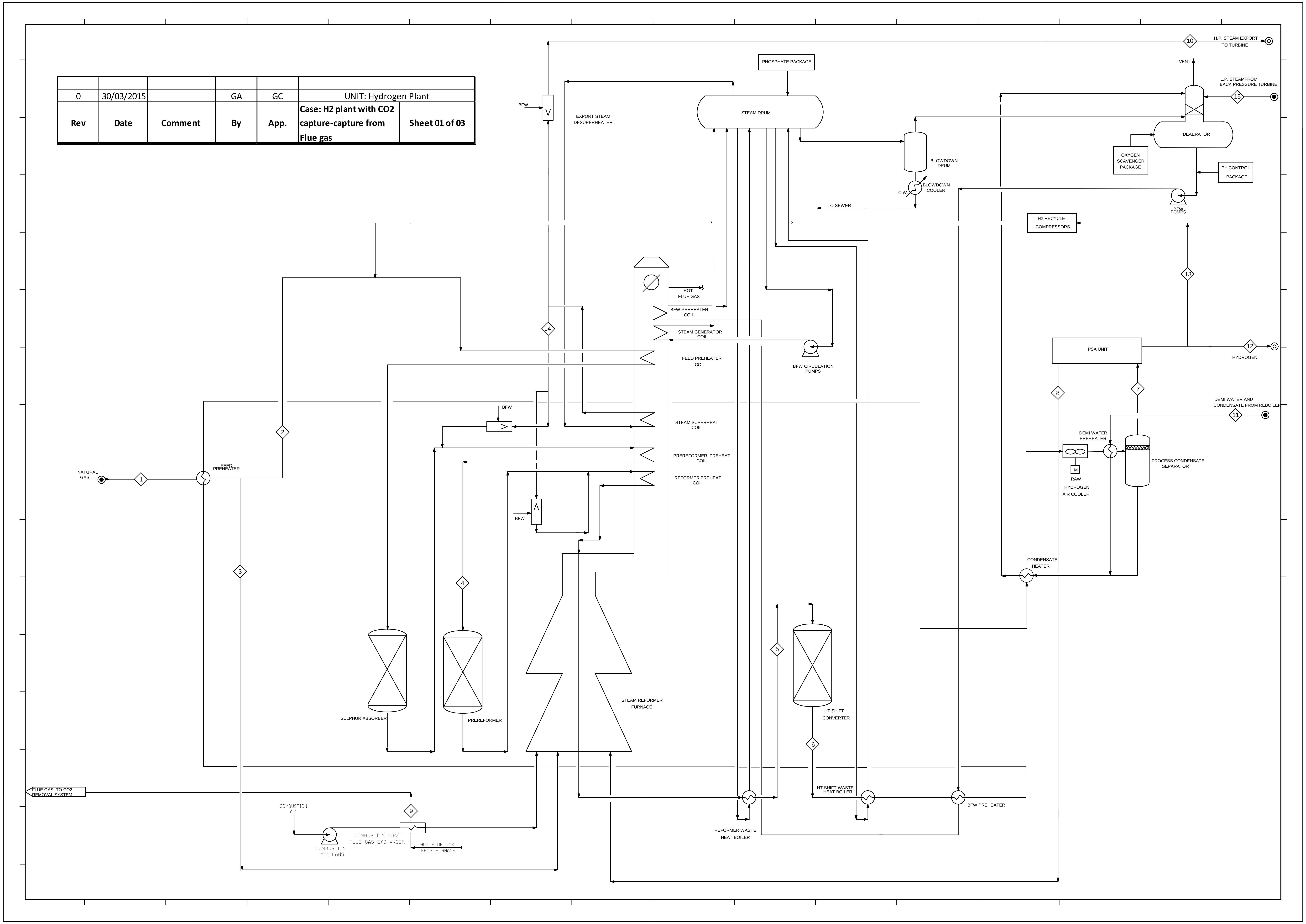
The operation of the whole plant is supported by additional utilities and facilities. These are presented in Section 2.4.4.

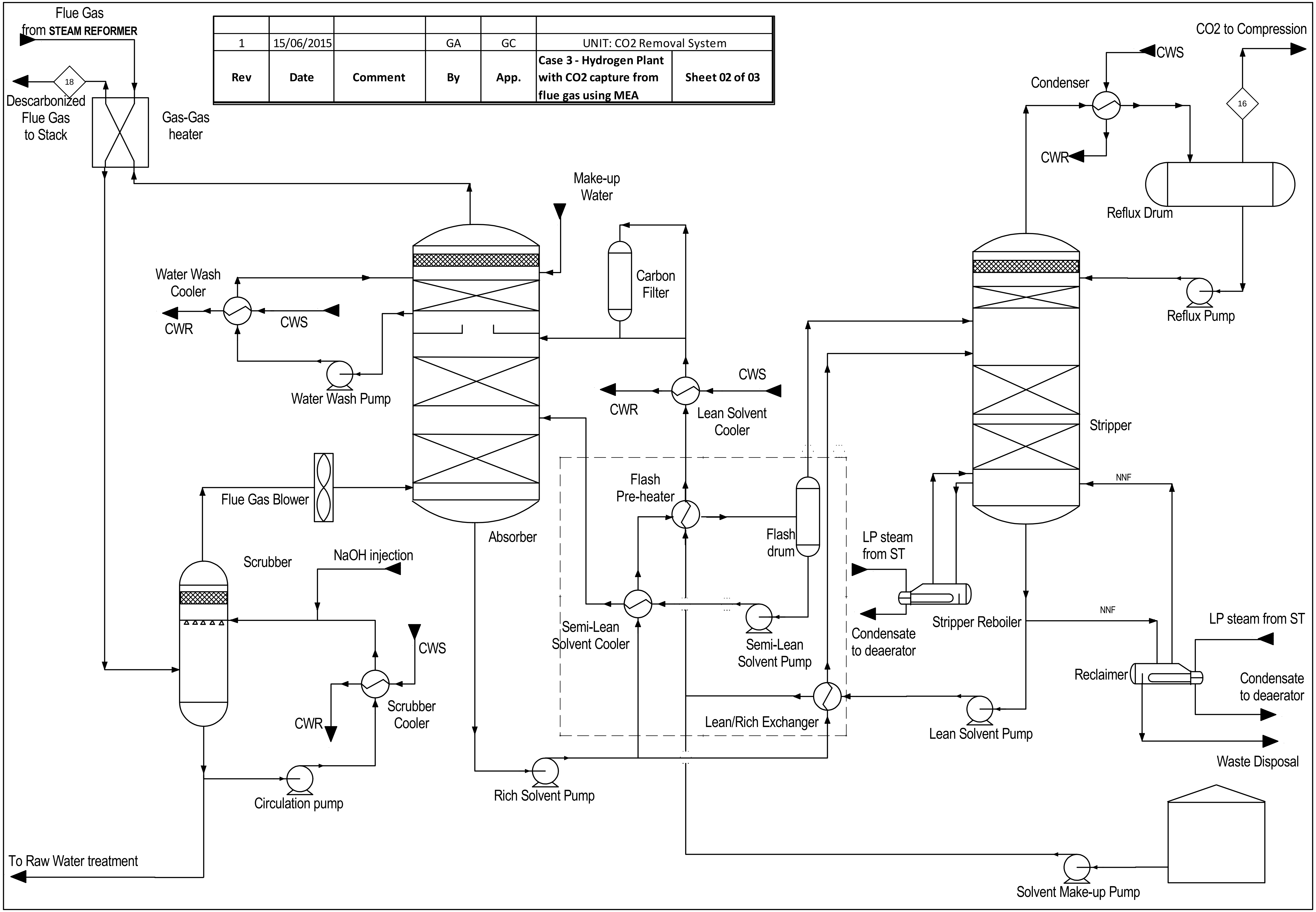
7.5. Process Flow Diagram (Hydrogen Plant and CO_2 Capture System)

The PFDs enclosed shows the different processes included in the Hydrogen Plant, the CO_2 Capture Plant and the CO_2 Compression and Dehydration Unit.

The processes involving the Hydrogen Plant are described in Section 2.4. The processes involving the CO_2 capture plant and the CO_2 Compression and Dehydration Unit are described in Section 7.4.

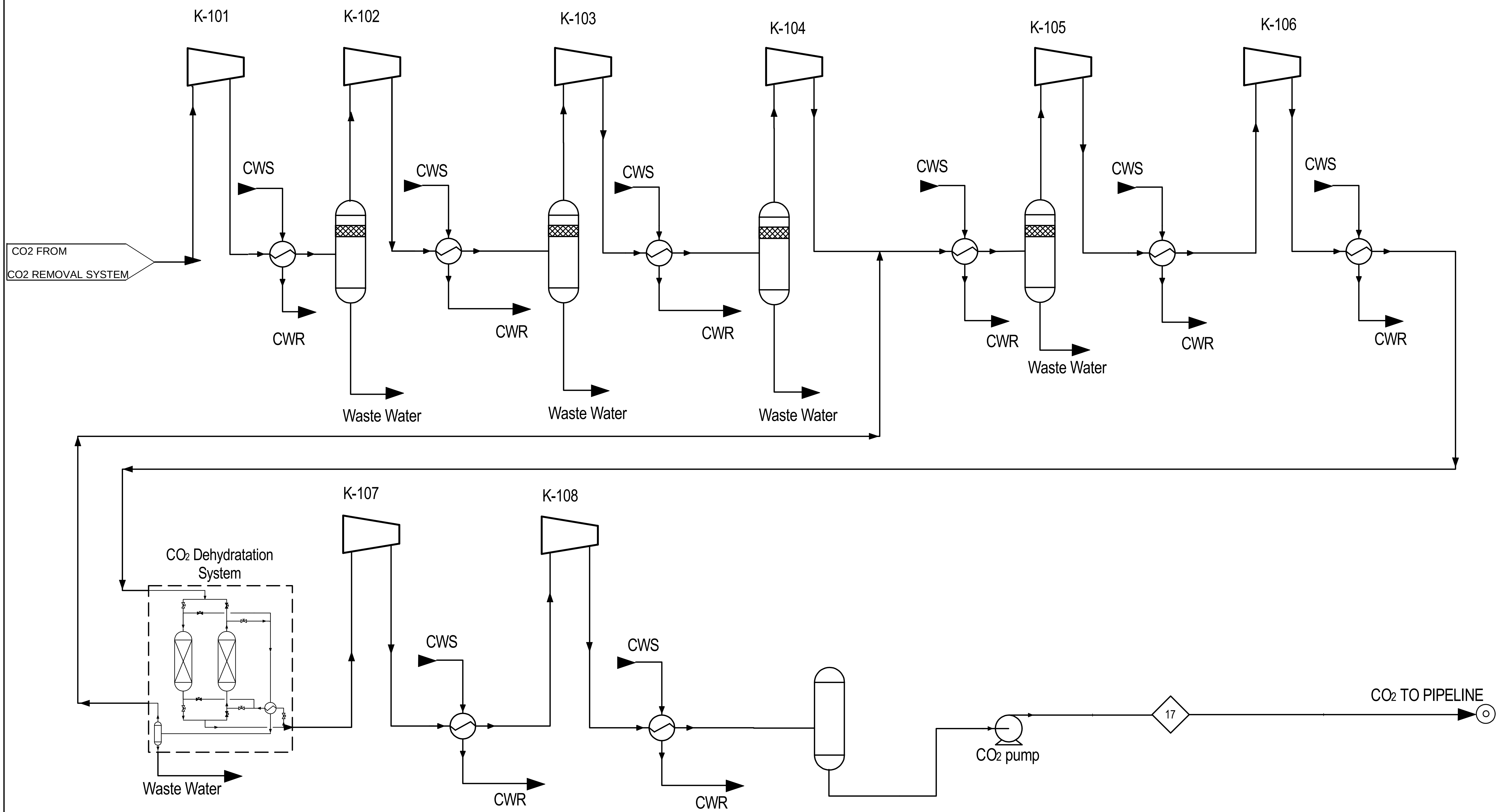
0	30/03/2015		GA	GC	UNIT: Hydrogen Plant	
Rev	Date	Comment	By	App.	Case: H2 plant with CO2 capture-capture from Flue gas	Sheet 01 of 03





The BFD above is a simplified representation of a Post combustion CO2 removal system. Equipment shown within the dotted line and relevant configuration may change depending on Licensor Technology

1	16/06/2015		GA	GC	UNIT: CO2 Compressor	
Rev	**Date**	**Comment**	**By**	**App.**	**Case 3 - Hydrogen Plant with CO2 capture from flue gas using MEA**	**Sheet 03 of 03**



7.6. Heat and Mass Balance

The heat and mass balances reported in this section makes reference to the Process Flow Diagram presented in Section 7.5.

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HEAT AND MATERIAL BALANCE
Case 3 - Hydrogen Plant with CO2 capture from flue gas using MEA

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG					
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	GC	GC
FWI CONTRACT:	1BD0840A	1	June 2015	GA	GC	GC
LOCATION:	THE NETHERLAND					

Stream		1	2	3	4	5	6	7	8	9	10	11	12
Description		Natural Gas From B.L.	Natural Gas feedstock to Hydrogen Plant	Natural Gas fuel to burners	Purified Feedstock to Pre-reformer	HTS Reactor Inlet	HTS Reactor Outlet	PSA inlet	PSA Tail gas	Flue gas to CO2 removal System	HP Steam export	Demi Water (make up) and condensate stripper reboiler	Hydrogen to B.L
Temperature	*°C*	9	120	112	500	320	412	35	28	136	395	15	40
Pressure	*MPa*	7.00	3.71	0.50	3.39	2.80	2.77	2.58	0.13	0.02	4.23	0.60	2.50
Molar Flow	*kmol/h*	1863.5	1455.8	407.8	5514.0	8370.3	8370.3	6596.9	2106.3	10651.1	5410.7	7960.0	4461.5
Mass Flow	*kg/h*	33579	26231	7348	98874	101667	101667	69711	60658	312928	97475	143400	8994
Composition													
CO2	*mol/mol*	0.0200	0.0200	0.0200	0.0053	0.0492	0.1283	0.1627	0.5095	0.1897	0.0000	0.0000	0.0000
CO	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.1156	0.0366	0.0464	0.1454	0.0000	0.0000	0.0000	0.0000
Hydrogen	*mol/mol*	0.0000	0.0000	0.0000	0.0053	0.5171	0.5961	0.7563	0.2369	0.0000	0.0000	0.0000	0.9999+
Nitrogen	*mol/mol*	0.0089	0.0089	0.0089	0.0023	0.0015	0.0015	0.0020	0.0062	0.6282	0.0000	0.0000	0.0000
Oxygen	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0109	0.0000	0.0000	0.0000
Methane	*mol/mol*	0.8900	0.8900	0.8900	0.2350	0.0238	0.0238	0.0302	0.0945	0.0000	0.0000	0.0000	0.0000
Ethane	*mol/mol*	0.0700	0.0700	0.0700	0.0185	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	*mol/mol*	0.0100	0.0100	0.0100	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	*mol/mol*	0.0010	0.0010	0.0010	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	*mol/mol*	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	*mol/mol*	0.0000	0.0000	0.0000	0.7307	0.2927	0.2137	0.0024	0.0076	0.1712	1.0000	1.0000	0.0000
Contaminants:													
H2S	*ppm v*	(1)											
NOx	*mg/Nm3*												

Notes:

(1) For feedstock purification section design purposes 5 ppmv of H2S have been assumed in NG to Hydrogen Plant

HEAT AND MATERIAL BALANCE
Case 3 - Hydrogen Plant with CO2 capture from flue gas using MEA

		REV	DATE	BY	CHKD	APP
CLIENT:	IEA GHG	**REV**	**DATE**	**BY**	**CHKD**	**APP**
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE	0	April 2015	GA	GC	GC
FWI CONTRACT:	1BD0840A	1	June 2015	GA	GC	GC
LOCATION:	THE NETHERLAND					

Stream		13	14	15	16	17	18
Description		H2 Recycle	HP Steam to process	LP Steam To Deareator	CO2 from capture unit to Compressor	CO2 to Pipeline	Decarbonized Flue gas to Stack
Temperature	*°C*	40	400	177	43	24	43
Pressure	*MPa*	2.51	4.29	0.44	0.16	11.00	0.10
Molar Flow	*kmol/h*	29.1	4157.2	38.9	1925.8	1818.9	7672.6
Mass Flow	*kg/h*	59	74892	700	81998	80048	211995
Composition							
CO2	*mol/mol*	0.0000	0.0000	0.0000	0.9450	0.9999+	0.0263
CO	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	(1)
Hydrogen	*mol/mol*	0.9999+	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.8721
Oxygen	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0151
Methane	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ethane	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	*mol/mol*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	*mol/mol*	0.0000	1.0000	1.0000	0.0550	0.0000	0.0865
Contaminants:							
H2S	*ppm v*						
NOx	*mg/Nm3*						120 max

Notes:

(1) 30 mg/Nm3 max

7.7. Plant Performance Data

The table below summarizes the productions/ consumptions and CO_2 emissions relevant to the overall Unit Hydrogen plant with CO_2 capture-capture from syngas case.

Plant Performance Data Case 3		
INLET STREAMS		
Natural Gas (as Feedstock)	t/h	26.231
Natural Gas (as Fuel)	t/h	7.348
Natural Gas (Total Consumption)	t/h	33.579
Natural Gas LHV	MJ/kg	46.50
Total Energy Input	MW	433.72
OUTLET STREAMS		
Hydrogen Product to BL	t/h	8.994
	Nm^3/h	100,000
Hydrogen LHV	MJ/kg	119.96
Total Energy in the Product	MW	299.70
POWER BALANCE		
Gross Power Output from the COGEN Plant	MWe	11.700
Hydrogen Plant Power Consumption	MWe	-1.314
COGEN Plant + Utilities + BoP Consumption	MWe	-1.677
CO2 Capture Plant Consumption	MWe	-2.001
CO2 Compression and Dehydration Unit	MWe	-6.282
Excess Power to the Grid	MWe	0.426
SPECIFIC CONSUMPTIONS		
Natural Gas (as Feedstock)	$GJ/1000\ Nm^3\ H_2$	12.197
Natural Gas (as Fuel)	$GJ/1000\ Nm^3\ H_2$	3.416
Feed + Fuel	$GJ/1000\ Nm^3\ H_2$	15.614
SPECIFIC EMISSIONS		
Specific CO2 Emission	$t/1000\ Nm^3\ H_2$	0.0888
Specific CO2 Captured	$t/1000\ Nm^3\ H_2$	0.8004
Overall CO2 Capture Rate (Case Specific)		90.00%
Overall CO2 Capture Rate (as Compared to Base Case)		89.02%

7.8. Preliminary Utilities Consumption

This section presents the different utilities consumption (usage) of the Hydrogen Plant, Power Island, CO_2 Capture Plant, CO_2 Compression and Dehydration, and others.

FOSTER WHEELER

ESTIMATED UTILITY CONSUMPTIONS

CUSTOMER NAME: IEAGHG		Case 3 - Hydrogen Plant with CO2 capture from flue gas using MEA	REV.	REV. 0	REV. 1	REV. 2			SHEET 1 OF 1
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H2 PRODUCTION WITH CO2 CAPTURE		BY	GA					
FWI CONTRACT:	1BD0840 A		CHKD	GC					
LOCATION:	THE NETHERLAND		DATE	April 2015					

	ELECTRIC POWER		STEAM t / h			EFFLUENT	LOSSES	DMW	RAW WATER	COOLING WATER		SEA WATER		FUEL	INSTR. AIR	Nitrogen
	LOAD BHP	kW	LP	MP	HP	t/h	t/h	t/h	t/h	ΔT (°C)	m³/hr	ΔT (°C)	m³/hr	MMKcal/h	Nm^3/h	Nm^3/h
HYDROGEN PLANT		1,314	0.7	0.00		-2.40	-43.9 (2)	143.4 (1)	0.00	11	13.9			81.7	100	(250)
					-97.1											
CO2 CAPTURE		2,001	96.4							11	5,601					
								-96.4	-19.00							
CO2 COMPRESSION		6,282								11	76	7	1,638			
POWER ISLAND					97.1											
		-11,700	-97.1													
UTILITIES / BoP		1,677				-14.1			61.1	11	-5,691	7	8,951	0.5	100	(250)
								-47.0							-200	(-500)
TOTAL		-427	0	0	0	-16.5	-43.9	0	42.1	-	0	-	10,589	82.2	0	0

NOTES:

(1) DMW is the sum of DMW plus condensate from CO2 capture unit reboiler

(2) Losses includes water consumed in the reaction and deaerator vent

(3) Water effluent (to be sent to WWT) includes demi plant eluate and steam drum blowdown in the hydrogen plant

7.9. Preliminary Equipment List and Size of Main Components/Packages

This section presents the preliminary list of equipment and main components/packages relevant to the Hydrogen Plant, Power Island, CO_2 Capture Plant, CO_2 Compression and Dehydration and BoP of Case 3.

The size of the main equipment included for the CO_2 Capture Plant are not provided since the relevant information used in this study are retrieved from other reference studies which are confidential.

					REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	**PRELIMINARY EQUIPMENT LIST**									
	CLIENT:	IEA GHG			0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE								OF
	FWI CONTRACT:	1BD0840A								
	LOCATION	THE NETHERLAND								8
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA								
	UNIT	HYDROGEN PLANT								

ITEM No.	DESCRIPTION	TYPE	SIZE ID mm	SIZE L / H mm	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
DRUMS										
	FUEL GAS K.O. DRUM	VERTICAL								
	STEAM DRUM	HORIZONTAL								
	PROCESS CONDENSATE SEPARATOR	VERTICAL								
	BLOWDOWN DRUM	VERTICAL								
	DEAERATOR	Stripping Section: Vertical Storage Section: Horizontal								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						8
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	SIZE ID mm	SIZE L / H mm	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
REACTORS										
	SULPHUR ABSORBERS	VERTICAL	2450	3650	4.075	400				
	PRE-REFORMER	VERTICAL	2100	3050	4.075	530				
	SHIFT CONVERTER	VERTICAL	3400	4400	3.080	430				

FOSTER WHEELER

PRELIMINARY EQUIPMENT LIST

		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						
LOCATION	THE NETHERLAND						
CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						8
UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS & COILS										
	FEED PRE-HEATER	SHELL & TUBE								
	HTS WASTE HEAT BOILER	SHELL & TUBE								
	BFW PRE-HEATER	SHELL & TUBE								
	CONDENSATE HEATER	SHELL & TUBE								
	DEMIWATER PRE-HEATER	SHELL & TUBE								
	BLOWDOWN COOLER	SHELL & TUBE								

PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	4
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						
LOCATION	THE NETHERLAND						
CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						8
UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE SS / TS	DESIGN TEMPERATURE SS / TS	MATERIAL	REMARKS		REV.
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS & COILS										
	COMBUSTION AIR / FLUE GAS EXCHANGER									
	BFW PREHEATER COIL	COIL								
	STEAM GENERATOR COIL	COIL								
	STEAM SUPERHEATER COIL	COIL								
	FEED PREHEATER COIL	COIL								
	PRE-REFORMER FEED PREHEATER COIL	COIL								
	REFORMER FEED PREHEATER COIL	COIL								
	REFORMER WASTE HEAT BOILER	SHELL & TUBE								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	**0**	April 2015	GA	GC	GC	5
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						8
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	DUTY	SIZE		DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			WIDTH	LENGTH						
		MM Kcal/h	mm	mm	MPa	°C	HEADER/TUBES			
AIR COOLERS										
	RAW HYDROGEN AIR COOLER									
FIRED EQUIPMENT										
	STEAM REFORMER FURNACE	82.63 (**)						(**) Radiant Duty		

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	6
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						8
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	HEAD	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			m^3/h	m	MPa	kW	CASING/IMPELLER			
PUMPS										
	BFW CIRCULATION PUMPS	Centrifugal								
	BFW FEED PUMPS	Centrifugal						Two pumps electrical motor driven		

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	**0**	April 2015	GA	GC	GC	7
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						**OF**
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						8
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
COMPRESSORS & BLOWERS										
	RECYCLE HYDROGEN COMPRESSORS PACKAGE	Reciprocating	653	2.505 / 4.001	4.40	16				
	COMBUSTION AIR BLOWERS							Two Blowers: one operating, one spare		

FWI -110/45 BASE: EQLIST0_00.XLT PRINTED ON: 24/06/2015

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	8
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						8
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						
	UNIT	HYDROGEN PLANT						

ITEM No.	DESCRIPTION	TYPE	FLOW Nm^3/h	PRESSURE INLET/OUTLET MPa	DESIGN PRESSURE MPa	DESIGN TEMPERATURE °C	MATERIAL	REMARKS		REV.
MISCELLANEA										
	STEAM VENT SILENCER									
	REFORMER STEAM DESUPERHEATER									
	PREREFORMER STEAM DESUPERHEATER									
	PHOSPHATE PACKAGE									
	EXPORT STEAM DESUPERHEATER									
	OXYGEN SCAVENGER PACKAGE									
	pH CONTROL PACKAGE									
	PSA UNIT		147865	2.58/2.51 (H2 side)	2.8	80				

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	SIZE		DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			ID	L / H						
			mm	mm	MPa	°C				
TOWERS										
	ABSORBER	VERTICAL								
	STRIPPER	VERTICAL								
DRUMS										
	FLASH DRUM	HORIZONTAL								
	AMINE SOLUTION TANK	HORIZONTAL								
	SCRUBBER	VERTICAL								
	REFLUX DRUM	HORIZONTAL								

FOSTER WHEELER	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM FLUE GAS						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	DUTY	AREA	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
					SS / TS	SS / TS				
			MM kcal/h	m^2	MPa	°C				
HEAT EXCHANGERS										
	LEAN/RICH AMINE EXCHANGER	SHELL & TUBE								
	LEAN SOLVENT COOLER	SHELL & TUBE								
	STRIPPER CONDENSER									
	STRIPPER REBOILER	KETTLE								
	RECLAIMER	KETTLE								
	WATER WASH COOLER									
	SCRUBBER COOLER									
	SEMI-LEAN SOLVENT COOLER									
	GAS -GAS HEATER									

PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	3
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						
LOCATION	THE NETHERLAND						
CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM FLUE GAS						5
UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	DUTY MM kcal/h	AREA m^2	DESIGN PRESSURE SS / TS MPa	DESIGN TEMPERATURE SS / TS °C	MATERIAL	REMARKS		REV.
PUMPS										
	BOOSTER PUMPS	CENTRIFUGAL								
	REFLUX PUMP	CENTRIFUGAL								
	SOLVENT MAKE UP PUMP									
	SEMI-LEAN SOLVENT PUMP									
	RICH SOLVENT PUMP									
	CIRCULATION PUMP									
	WASH WATER PUMP									
	CO2 PUMP (CO2 COMPRESSOR PACKAGE)	CENTRIFUGAL								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
FOSTER WHEELER	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	4
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM FLUE GAS						5
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
COMPRESSORS & BLOWERS										
	CO2 COMPRESSORS	CENTRIFUGAL						Brake Power: 6170 kW EIGHT Stages, Pin= 0.16 MPa, Pout= 11 MPa, Tin =43°C, Tout=24°C, MW=42.6, Electical motor to be included Compressor Package includes 4 separators and eight trim coolers		
	FLUE GAS BLOWER									

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	GA	GC	GC	5
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						5
	CASE	HYDROGEN PLANT WITH CO2 CAPTURE-CAPTURE FROM FLUE GAS						
	UNIT	CO2 REMOVAL SYSTEM						

ITEM No.	DESCRIPTION	TYPE	FLOW	PRESSURE INLET/OUTLET	DESIGN PRESSURE	Brake Power	MATERIAL	REMARKS		REV.
			Nm^3/h	MPa	MPa	kW	CASING/IMPELLER			
MISCELLANEA										
	DRYER UNIT PACKAGE									
	CARBON FILTER									

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						1
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						
	UNIT	POWER ISLAND						

CONFIDENTIAL

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
POWER ISLAND										
	STEAM TURBINE AND GENERATOR PACKAGE									
	Including									
	STEAM TURBINE	Backpressure type	11 MWe	4.2 / 0.35				Including: lube oil system; Cooling system; Hydraulic control system; Seal system Drainage system Gland condenser		
	STEAM TURBINE GENERATOR		13 MVA					Including relevant auxiliaries		
	STEAM TURBINE BYPASS SYSTEM									

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	1
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						
	LOCATION	THE NETHERLAND						
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						3
	UNIT	UTILITIES AND BOP						

CONFIDENTIAL

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
COOLING WATER SYSTEM										
	SEA WATER PUMPS	Centrifugal	5500 m3/h x 25 m 560 kWe					Two operating one spare		
	SEA WATER / CLOSED COOLING WATER EXCHANGER		70 MWth							
	CLOSED COOLING WATER PUMPS		5800 m3/h x 25 m 600 kWe					One operating one spare		
	CLOSED COOLING WATER CIRCUIT EXPANSION DRUM									
	CORROSION INHIBITOR PACKAGE									
INSTRUMENT / PLANT AIR SYSTEM										
	AIR COMPRESSOR PACKAGE							including: - Air Compressor - Inter/after coolers - KO Drums (including final KO drum)		
	AIR DRYING PACKAGE	Adsorption bed	200 Nm3/h					including: - Adsorbent Bed (with automatic regenaration system) - Regeneration Electrical Heater - Pre Filters - After Filters		
	IA RECEIVER DRUM	vertical								

	PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
	CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	2
	PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
	FWI CONTRACT:	1BD0840A						3
	LOCATION	THE NETHERLAND						
	CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						
	UNIT	UTILITIES AND BOP						

CONFIDENTIAL

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
RAW / DEMI WATER SYSTEM										
	RAW WATER TANK	Fixed roof						12 h storage		
	RAW WATER FILTRATION PACKAGE		65 m3/h							
	POTABLE WATER TANK	Fixed roof						12 h storage		
	POTABLE WATER PACKAGE									
	DEMI WATER PLANT FEED PUMP		65 m3/h x 25 m 7.5 kW							
	DEMI WATER PACKAGE UNIT		50 m3/h DW production					Including: - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system		
	DEMIWATER PUMPS		50 m3/h x 50 m 15 kW							
	DEMIWATER TANK	Fixed roof						12 h storage		

PRELIMINARY EQUIPMENT LIST		REVISION	DATE	BY	CHKD	APP	SHEET
CLIENT:	IEA GHG	0	April 2015	NF	GC	GC	3
PROJECT NAME:	TECHNO-ECONOMIC EVALUATION OF H_2 PRODUCTION WITH CO2 CAPTURE						OF
FWI CONTRACT:	1BD0840A						
LOCATION	THE NETHERLAND						3
CASE	CASE 3: HYDROGEN PLANT WITH CO2 CAPTURE FROM FLUE GAS USING MEA						
UNIT	UTILITIES AND BOP						

CONFIDENTIAL

ITEM No.	DESCRIPTION	TYPE	SIZE	PRESSURE INLET/OUTLET	DESIGN PRESSURE	DESIGN TEMPERATURE	MATERIAL	REMARKS		REV.
			-	MPa	MPa	°C				
NITROGEN GENERATION PACKAGE										
	NITROGEN PRODUCTION PACKAGE		500 Nm3/h					Including: - Intake Air Filter - Air Compressor - Air Receiver - Inter/after coolers - KO Drums - Molecular Sieve Water Absorber (Air Dryer) - Chiller Unit - One Expansion Turbine - One Cryogenic Distillation Column - One Main Heat Exchanger		
	LIQUID NITROGEN STORAGE AND VAPORISATION PACKAGE		500 Nm3/h					Including: - Liquid Nitrogen Storage tank - Nitrogen Vaporizer (Air Fin Type) - Nitrogen heater (electrical)		
	GASEOUS NITROGEN BUFFER VESSEL									
FLARE SYSTEM										
	FLARE KO DRUM	Horizontal								
	FLARE PACKAGE		Max relief flowrate 102,000 kg/h; MW:12					Including riser; tip, seal drum		
	FLARE KO DRUM PUMPS	Centrifugal						One operating one spare		
BoP										
	INTERCONNECTING									
	BUILDING (CONTROL ROOM, ELECTRICAL SUBSTATION, LAB)									
	DRAIN SYSTEM									
	FIRE FIGHTING									
	ELECTRICAL SYSTEM							Up to generator terminals		

8. Economic Evaluation

The purpose of this section is to present the results of the economic analysis carried out in evaluating the Levelised Cost of Hydrogen (LCOH) and the CO_2 Avoidance Cost (CAC) of the different study cases (as listed in Table 1).

Table 1 - Study Cases

Cases	Description
Base case	Steam reformer w/o CO_2 capture
Case 1A	CO_2 capture from syngas using MDEA
Case 1B	CO_2 capture from syngas using MDEA with H_2-rich fuel firing burners
Case 2A	CO_2 capture from PSA tail gas using MDEA
Case 2B	CO_2 capture from PSA tail gas using Cryogenic and Membrane Technology
Case 3	CO_2 capture from flue gas using MEA

All inputs used to perform the economic analysis are set in accordance with the general assumptions and criteria reported in the Reference Document (Task 2) – see Annex I of this report.

The capital cost and the annual operating & maintenance (O&M) costs for the different cases have been evaluated and are presented in the succeeding sections, along with the results of the financial model.

The annual operating and maintenance costs are based on the overall heat and mass balances of each cases as presented in previous section.

Due to the possible variation to some of the assumed economic data, an exhaustive sensitivity analysis is also performed and presented in this chapter:

- Natural Gas Price,
- Electricity Price,
- Plant Economic Life,
- Discount Rate,
- Costs Related to CO_2 Emission (as Tax) and CO_2 Transport & Storage.

8.1. Investment Cost Estimates

8.1.1. Definitions

The basis of estimating the main capital and operating cost are described in the Reference Document (Task 2) – see Annex I of this report.

This section summarises the estimates on the Total Capital Requirement (TCR), also named as Total Investment Cost (TIC), of the various study cases.

The TCR is defined in general accordance to the White Paper "*Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants*", (March 2013), produced in collaboration with several authors from EPRI, IEAGHG, Carnegie Mellon University, MIT, IEA, GCCSI and Vattenfall.

The **Total Capital Requirement** (**TCR**) is defined as the sum of:

- Total Plant Cost (TPC)
- Interest during construction
- Spare parts cost
- Working capital
- Start-up costs
- Owner's costs.

The **Total Plant Cost** (**TPC**) of the different study cases is further broken down into the cost estimates of the different main process units:

- Reference Case: Hydrogen Plant w/o CO_2 Capture
    - Steam Reformer Based Hydrogen Plant
    - Power Island
    - Other Utilities and Balance of Plant (BoP)

- Hydrogen Plant w/ CO_2 Capture
    - Steam Reformer Based Hydrogen Plant
    - Power Island
    - CO_2 Capture Plant
    - CO_2 Compression and Dehydration Unit
    - Other Utilities and Balance of Plant (BoP)

8.1.2. Estimating Methodology

The estimate is an AACE Class 4 estimate (accuracy range +35%/-15%), based on 4Q2014 price level, in euro (€).

The Total Plant Cost (TPC) is defined as the installed cost of the plant, including contingencies. Furthermore, for each process units, the TPC is estimated based on the following items:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency.

The estimating methodology used for the evaluation of the Total Plant Cost (TPC) items of the process units is described in the following sections.

Direct Materials

For the different process units, the direct materials are estimated by using Amec Foster Wheeler's in-house database or conceptual estimating models.

Where detailed and sized equipment list has been developed, a K-base (commercially available software) has been used to produce the cost estimates. For units having capacity only, cost is based on previous estimates done for similar units, by scaling up or down (as applicable) the cost on capacity ratio.

Construction and EPC Services

For each unit or block of units, the construction and EPC services are factored based on the direct materials costs. The factor (multipliers) used are based on in-house data gathered from the cost estimates made in the past projects with similar plants.

Other Costs

Other costs mainly include:

- Temporary facilities;
- Vendor assistance;
- Miscellaneous expenses (i.e. heavy lift, chemical cleaning,…).

Other costs are estimated as a percentage of the construction cost, in accordance with Amec Foster Wheeler's experience and in-house database.

Contingency

A project contingency is added to the capital cost to give a 50% probability of a cost over-run or under-run. For the accuracy considered in this study, Amec Foster Wheeler's view is that contingency should be in the range of 20% of the total installed cost.

The Total Capital Requirement (TCR) is the sum of following items with their corresponding assumptions:

- Total Plant Cost (TPC) [1] – as reported in the succeeding pages
- Interest during construction which is assumed to be the same as the discount rate (8%).
- Spare parts cost which is assumed as 0.5% of the TPC.[2]
- Working capital, including 30 days inventories of chemicals and other consumables.
- Start-up costs, which is assumed as 2% of TPC, plus 25% of the monthly feedstock and fuel cost, 3 months of the operation labour and maintenance labour cost, and 1 month of cost related to catalyst, chemicals, waste disposals cost and maintenance materials cost.[3]
- The cost for the initial solvent inventory required for the amine based CO_2 capture plant
- Owner's costs and fees, which assumed as 7% of TPC.[4]

8.1.3. *Summary of Results - TPC and TCR*

The TPC and TCR for the different cases evaluated in this study are summarised in Table 2 below. The breakdown of the TPC for the different study cases are presented in the succeeding pages. Each table includes a related pie chart of the Total Plant Cost to show the percentage weight of each unit relative to the overall capital cost of the plant. The breakdown of the TCR are presented in Annex III.

Table 2. TPC and TCR of the Different Study Cases

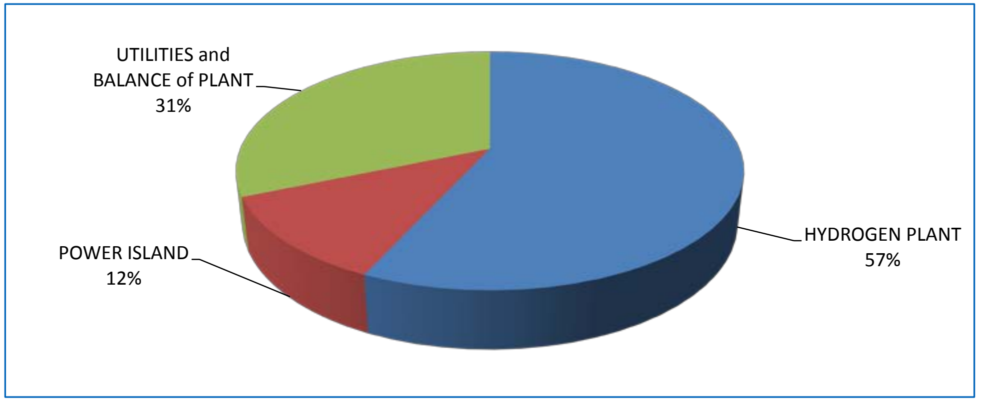
Case	Total Plant Cost (TPC) (M€)	Total Capital Requirement (TCR) (M€)
Base Case	170.95	222.89
Capture from Shifted Syngas		
Case 1A	201.80	263.91
Case 1B	228.48	298.68
Capture from PSA Tail Gas		
Case 2A	226.07	295.21
Case 2B	241.44	313.87
Capture from Flue Gas		
Case 3	305.33	398.48

[1] The capital expenditure curve during construction is based on 20%-45%-35% distribution.
[2] The capital expenditure curve for the spare parts also follows the 20%-45%-35% distribution.
[3] The Start-Up cost are charged on Year -1 (3rd year of the project).
[4] All of the owner's cost is charged on Year -3 (1st year of the project).

Techno-Economic Evaluation of Standalone H2 Plant
Base case - Steam reformer w/o capture

CONTRACT: 1-BD-0840A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: JUNE 2015
REV.: 0

POS.	DESCRIPTION	HYDROGEN PLANT	POWER ISLAND	UTILITIES and BALANCE of PLANT	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	40,677,000	8,559,000	18,848,000	68,084,000	1) ESTIMATE IS BASED ON 4th QUARTER YEAR 2014 PRICE LEVEL
2	CONSTRUCTION	25,698,000	5,643,000	17,807,000	49,148,000	2) ESTIMATE ACCURACY : +35 -15% AACE CLASS IV
3	**DIRECT FIELD COST**	**66,375,000**	**14,202,000**	**36,655,000**	**117,232,000**	
4	OTHER COSTS	1,885,000	483,000	1,290,000	3,658,000	
5	EPC SERVICES	12,750,000	2,085,000	6,735,000	21,570,000	
6	**TOTAL INSTALLED COST**	**81,010,000**	**16,770,000**	**44,680,000**	**142,460,000**	
7	PROJECT CONTINGENCY	16,202,000	3,354,000	8,936,000	28,492,000	**BUSINESS CONFIDENTIAL**
8	**TOTAL PLANT COST (TPC)**	**97,212,000**	**20,124,000**	**53,616,000**	**170,952,000**	



Techno-Economic Evaluation of Standalone H2 Plant
Case 1A - CO2 capture from syngas using MDEA

CONTRACT: 1-BD-0840A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: JUNE 2015
REV.: 0

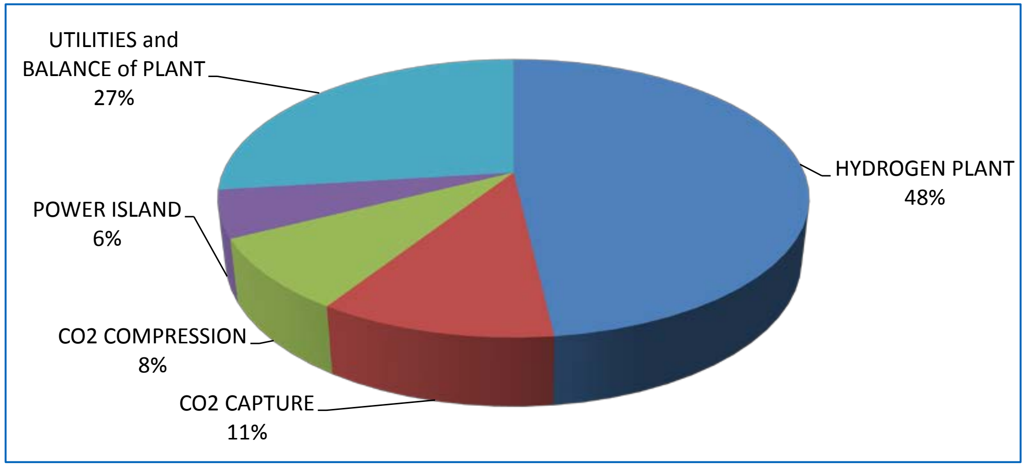
POS.	DESCRIPTION	HYDROGEN PLANT	CO2 CAPTURE	CO2 COMPRESSION	POWER ISLAND	UTILITIES and BALANCE of PLANT	TOTAL COST EURO
1	DIRECT MATERIAL	40,677,000	9,633,000	7,983,000	4,776,000	19,318,000	82,387,000
2	CONSTRUCTION	25,698,000	5,804,000	4,012,000	3,084,000	18,195,000	56,793,000
3	**DIRECT FIELD COST**	**66,375,000**	**15,437,000**	**11,995,000**	**7,860,000**	**37,513,000**	**139,180,000**
4	OTHER COSTS	1,885,000	415,000	300,000	235,000	1,270,000	4,105,000
5	EPC SERVICES	12,750,000	2,538,000	1,875,000	1,125,000	6,597,000	24,885,000
6	**TOTAL INSTALLED COST**	**81,010,000**	**18,390,000**	**14,170,000**	**9,220,000**	**45,380,000**	**168,170,000**
7	PROJECT CONTINGENCY	16,202,000	3,678,000	2,834,000	1,844,000	9,076,000	33,634,000
8	**TOTAL PLANT COST (TPC)**	**97,212,000**	**22,068,000**	**17,004,000**	**11,064,000**	**54,456,000**	**201,804,000**

NOTES / REMARKS

1) ESTIMATE IS BASED ON 4th QUARTER YEAR 2014 PRICE LEVEL

2) ESTIMATE ACCURACY : +35 -15% AACE CLASS IV

BUSINESS CONFIDENTIAL

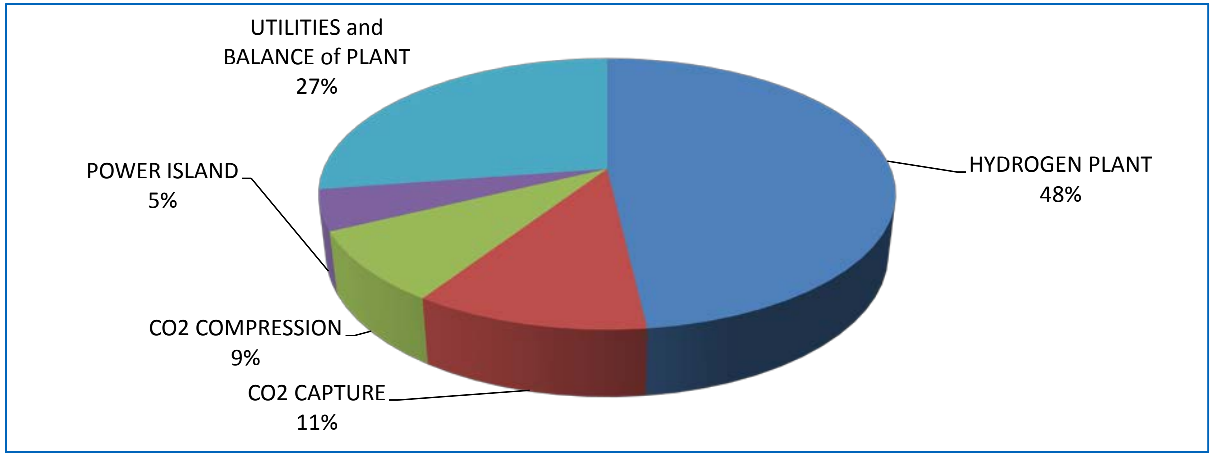


Techno-Economic Evaluation of Standalone H2 Plant

Case 1B - CO2 capture from syngas using MDEA with H2-rich fuel firing burners

CONTRACT: 1-BD-0840A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: JUNE 2015
REV.: 0

POS.	DESCRIPTION	HYDROGEN PLANT	CO2 CAPTURE	CO2 COMPRESSION	POWER ISLAND	UTILITIES and BALANCE of PLANT	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	47,449,000	11,340,000	8,757,000	4,818,000	22,712,000	95,076,000	1) ESTIMATE IS BASED ON 4th QUARTER YEAR 2014 PRICE LEVEL
2	CONSTRUCTION	29,420,000	6,581,000	4,848,000	3,042,000	20,487,000	64,378,000	2) ESTIMATE ACCURACY : +35 -15% AACE CLASS IV
3	**DIRECT FIELD COST**	**76,869,000**	**17,921,000**	**13,605,000**	**7,860,000**	**43,199,000**	**159,454,000**	
4	OTHER COSTS	2,071,000	530,000	442,000	215,000	1,435,000	4,693,000	
5	EPC SERVICES	12,750,000	2,692,000	2,120,000	1,120,000	7,571,000	26,253,000	
6	**TOTAL INSTALLED COST**	**91,690,000**	**21,143,000**	**16,167,000**	**9,195,000**	**52,205,000**	**190,400,000**	
7	PROJECT CONTINGENCY	18,338,000	4,229,000	3,234,000	1,839,000	10,441,000	38,081,000	**BUSINESS CONFIDENTIAL**
8	**TOTAL PLANT COST (TPC)**	**110,028,000**	**25,372,000**	**19,401,000**	**11,034,000**	**62,646,000**	**228,481,000**	



Techno-Economic Evaluation of Standalone H2 Plant
Case 2A - CO2 capture from PSA tail gas using MDEA

CONTRACT: 1-BD-0840A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: JUNE 2015
REV.: 0

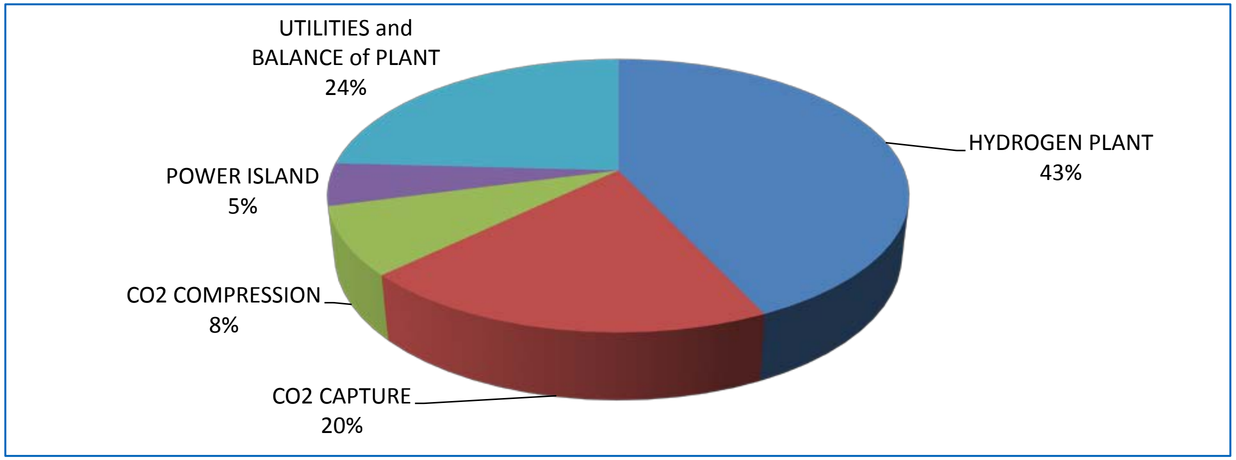
POS.	DESCRIPTION	HYDROGEN PLANT	CO2 CAPTURE	CO2 COMPRESSION	POWER ISLAND	UTILITIES and BALANCE of PLANT	TOTAL COST EURO
1	DIRECT MATERIAL	40,677,000	22,470,000	8,165,000	4,772,000	19,443,000	95,527,000
2	CONSTRUCTION	25,698,000	10,521,000	4,501,000	3,075,000	18,280,000	62,075,000
3	**DIRECT FIELD COST**	**66,375,000**	**32,991,000**	**12,666,000**	**7,847,000**	**37,723,000**	**157,602,000**
4	OTHER COSTS	1,885,000	1,200,000	425,000	216,000	1,280,000	5,006,000
5	EPC SERVICES	12,750,000	3,139,000	2,038,000	1,400,000	6,455,000	25,782,000
6	**TOTAL INSTALLED COST**	**81,010,000**	**37,330,000**	**15,129,000**	**9,463,000**	**45,458,000**	**188,390,000**
7	PROJECT CONTINGENCY	16,202,000	7,466,000	3,026,000	1,893,000	9,092,000	37,679,000
8	**TOTAL PLANT COST (TPC)**	**97,212,000**	**44,796,000**	**18,155,000**	**11,356,000**	**54,550,000**	**226,069,000**

NOTES / REMARKS

1) ESTIMATE IS BASED ON 4th QUARTER YEAR 2014 PRICE LEVEL

2) ESTIMATE ACCURACY : +35 -15% AACE CLASS IV

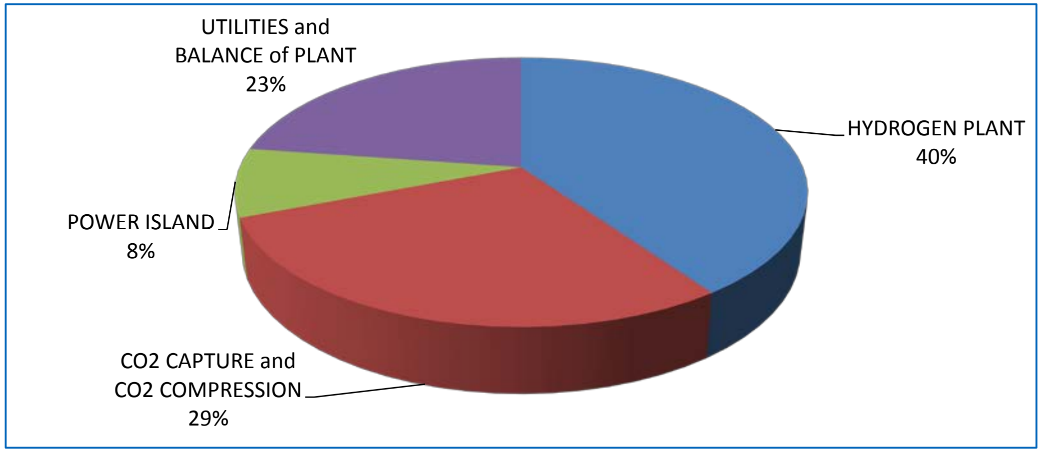
BUSINESS CONFIDENTIAL



Techno-Economic Evaluation of Standalone H2 Plant
Case 2B - CO2 capture from PSA tail gas using Cryogenic and Membrane Technology

CONTRACT: 1-BD-0840A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: JUNE 2015
REV.: 0

POS.	DESCRIPTION	HYDROGEN PLANT	CO2 CAPTURE and CO2 COMPRESSION	POWER ISLAND	UTILITIES and BALANCE of PLANT	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	40,677,000	31,792,000	8,534,000	19,394,000	100,397,000	1) ESTIMATE IS BASED ON 4th QUARTER YEAR 2014 PRICE LEVEL
2	CONSTRUCTION	25,698,000	17,181,000	5,590,000	18,183,000	66,652,000	2) ESTIMATE ACCURACY : +35 -15% AACE CLASS IV
3	**DIRECT FIELD COST**	**66,375,000**	**48,973,000**	**14,124,000**	**37,577,000**	**167,049,000**	
4	OTHER COSTS	1,885,000	1,220,000	396,000	1,274,000	4,775,000	
5	EPC SERVICES	12,750,000	7,807,000	2,040,000	6,779,000	29,376,000	
6	**TOTAL INSTALLED COST**	**81,010,000**	**58,000,000**	**16,560,000**	**45,630,000**	**201,200,000**	
7	PROJECT CONTINGENCY	16,202,000	11,600,000	3,312,000	9,126,000	40,240,000	**BUSINESS CONFIDENTIAL**
8	**TOTAL PLANT COST (TPC)**	**97,212,000**	**69,600,000**	**19,872,000**	**54,756,000**	**241,440,000**	



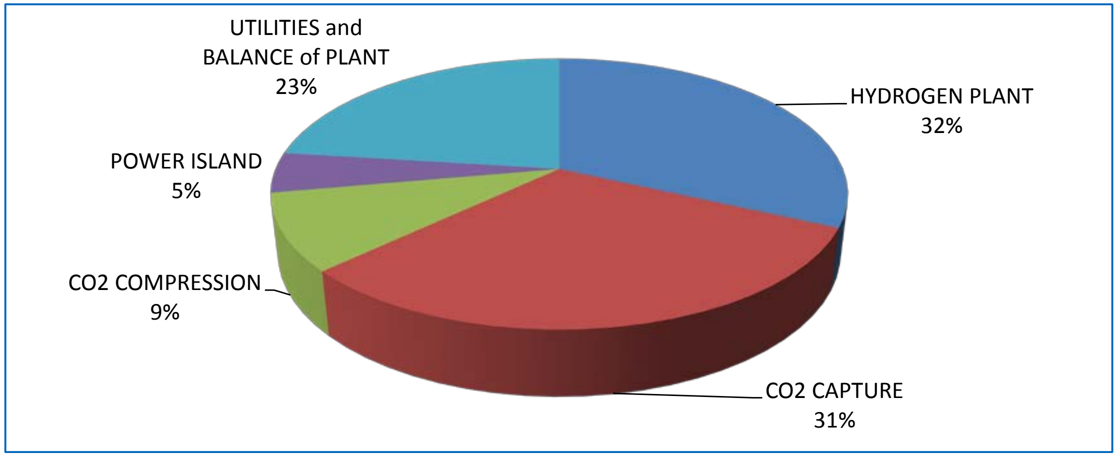
FOSTER WHEELER

Techno-Economic Evaluation of Standalone H2 Plant

Case 3 - CO2 capture from flue gas using MEA

CONTRACT: 1-BD-0840A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: JUNE 2015
REV.: 0

POS.	DESCRIPTION	HYDROGEN PLANT	CO2 CAPTURE	CO2 COMPRESSION	POWER ISLAND	UTILITIES and BALANCE of PLANT	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	40,677,000	42,933,000	13,341,000	6,366,000	25,808,000	129,125,000	1) ESTIMATE IS BASED ON 4th QUARTER YEAR 2014 PRICE LEVEL
2	CONSTRUCTION	25,698,000	23,811,000	6,600,000	4,038,000	22,589,000	82,736,000	2) ESTIMATE ACCURACY : +35 -15% AACE CLASS IV
3	**DIRECT FIELD COST**	**66,375,000**	**66,744,000**	**19,941,000**	**10,404,000**	**48,397,000**	**211,861,000**	
4	OTHER COSTS	1,885,000	1,632,000	528,000	284,000	1,582,000	5,911,000	
5	EPC SERVICES	12,750,000	10,925,000	2,894,000	1,485,000	8,614,000	36,668,000	
6	**TOTAL INSTALLED COST**	**81,010,000**	**79,301,000**	**23,363,000**	**12,173,000**	**58,593,000**	**254,440,000**	
7	PROJECT CONTINGENCY	16,202,000	15,861,000	4,673,000	2,435,000	11,719,000	50,890,000	**BUSINESS CONFIDENTIAL**
8	**TOTAL PLANT COST (TPC)**	**97,212,000**	**95,162,000**	**28,036,000**	**14,608,000**	**70,312,000**	**305,330,000**	



8.2. Annual Operating and Maintenance Cost

The definition of the Annual Operating and Maintenance (O&M) Cost is reported in the Reference Document (Task 2) – see Annex I of this report.

The succeeding sections summarised the estimated annual operating and maintenance costs for the different study cases. Generally, these are differentiated between:

- Variable cost;
- Fixed cost.

It should be noted that accurately distinguishing the allocation between the variable and fixed costs are not always feasible. Certain cost items may have both variable and fixed cost components; for example, the planned maintenance and inspection of the equipment such as steam turbine, SMR tubes, etc… are known to occur based on the number of running hours and should be allocated as variable components of the maintenance cost.

8.2.1. <u>Variable Cost</u>

Following tables presented in the succeeding pages summarise the variable costs for the different study cases. These include the following main cost items:

- Feedstock and fuel (natural gas)
- Raw water make-up
- Catalysts
- Chemicals.

The annual consumption of the various items reported are calculated using the overall mass and energy balances reported in this study based on the expected equivalent availability of the plant (i.e. 70% and 95% capacity factor for year 1 and year 2 to 25 respectively).

Reference prices used to estimate the cost of the consumables are summarized in the table below.

Item	Unit	Cost
Natural gas	€/GJ (LHV)	6
Raw water	€/m^3	0.20
Electricity (*)	€/MWh	80
CO_2 transport and storage	€/t CO_2 stored	10
CO_2 emission cost	€/t CO_2 emitted	0

(*) Electricity selling/buying price for the electricity export or import.

The following tables summarise the variable cost for the different study cases evaluated. Revenues relevant to the electricity selling price are also shown. For Case 2A, where power demand is higher than the power production, the cost related to the electricity import has been considered as an additional cost.

Yearly Variable Costs

Revision:	1
Date:	June 2015
Issued by:	NF
Approved by:	CG

Yearly Operating hours = 8322		Base case Hydrogen plant w/o capture			case 1A CO2 capture from syngas using MDEA			case 1B CO2 Capture from Syngas using MDEA with H2-Rich Fuel Firing Burners		
Consumables	**Unit Cost**	**Consumption**		**Operating Costs**	**Consumption**		**Operating Costs**	**Consumption**		**Operating Costs**
		Hourly	Yearly		Hourly	Yearly		Hourly	Yearly	
	€/t	kg/h	t/y	€/y	kg/h	t/y	€/y	kg/h	t/y	€/y
Feedstock + fuel										
Natural Gas	279.0	30,563	254,345	70,962,300	31,562	262,659	73,281,900	33,333	277,397	77,393,800
Auxiliary feedstock										
Raw make-up water	0.20	59,700	496,823	99,400	61,200	509,306	101,900	77,300	643,291	128,700
Chemicals	-	-	-	100,000	-	-	100,000	-	-	100,000
Catalysts	-	-	-	320,000			320,000			405,000
TOTAL YEARLY OPERATING COSTS	**Euro/year**			**71,481,700**			**73,803,800**			**78,027,500**
Revenues from electricity by-product	€/MWh	MWh	MWh/y	€/y	MWh	MWh/y	€/y	MWh	MWh/y	€/y
Electricity selling price / cost	80	9.9	82,538	**6,603,000**	1.5	12,416	**993,300**	1.5	**12,833**	**1,026,600**

Yearly Variable Costs

Revision:	1
Date:	June 2015
Issued by:	NF
Approved by:	CG

Yearly Operating hours = 8322		case 2A CO2 Capture from PSA Tail Gas using MDEA			case 2B CO2 Capture from PSA Tail Gas using Cryogenic and Membrane Technology			case 3 CO2 Capture from Flue Gas using MEA		
Consumables	**Unit Cost**	**Consumption**		**Operating Costs**	**Consumption**		**Operating Costs**	**Consumption**		**Operating Costs**
		Hourly	Yearly		Hourly	Yearly		Hourly	Yearly	
	€/t	kg/h	t/y	€/y	kg/h	t/y	€/y	kg/h	t/y	€/y
Feedstock + fuel										
Natural Gas	279.0	31,828	264,873	73,899,500	30,495	253,779	70,804,400	33,579	279,444	77,965,000
Auxiliary feedstock										
Raw make-up water	0.20	60,900	506,810	101,400	59,700	496,823	99,400	42,100	350,356	70,100
Chemicals	-	-	-	100,000	-	-	100,000	-	-	100,000
Catalysts	-	-	-	320,000	-	-	320,000	-	-	320,000
TOTAL YEARLY OPERATING COSTS	**Euro/year**			**74,420,900**			**71,323,800**			**78,455,100**
Revenues from electricity by-product	€/MWh	MWh	MWh/y	€/y (*)	MWh	MWh/y	€/y	MWh	MWh/y	€/y
Electricity selling price / cost	80	-1.1	-8,905	**-712,400**	0.3	2,405	**192,400**	0.4	**3,553**	**284,300**

(*) negative revenue figures means that electricty cost is imported and has to considered as additional cost

8.2.2. Fixed Cost

The Fixed Cost include:

- Operating Labour Costs
- Overhead Charges
- Maintenance Costs
- Other Fixed Costs

Operating Labour Cost

The Hydrogen Plants without and with CCS for the different study cases can be virtually divided into the following main areas of operation:

- Hydrogen plant + utilities
- Additional operators required for the CO_2 capture and compression unit

The same division is reflected in the design of the centralized control room, which has the same number of main DCS control groups, each one equipped with a number of control stations, from where the operation of the units of each area is controlled.

The area responsible and his assistant supervise each area of operation; both are daily position. The shift superintendent and the electrical assistant are common for the different areas; both are also shift position. The rest of the operation staff is structured around the standard positions: shift supervisors, control room operators and field operators.

The maintenance personnel are based on the use of external subcontractors for all medium to major types of maintenance work. Maintenance cost takes into account the outsourcing services required. The plant maintenance personnel, like the instrument specialists, performs routine maintenance and resolve emergency problems.

The yearly cost of the direct labour is estimated by assuming an annual average cost for each individuals equal to 60,000 Euro/year (referred to year 2014).

The following tables presented in the succeeding page illustrate the breakdown of the labour force for the different configurations evaluated in this study and along with the total direct labour cost.

Overhead Charges

All other company services not directly involved in the operation of the plant fall into this category, such as:

- Management;
- Administration;

- Personnel services;
- Technical services;
- Clerical staff.

These services could vary widely from company to company and are also dependent on the type and complexity of the operation. It is assumed that this cost is equal to 30% of the operating labour and maintenance labour cost.

Steam reformer			
	SR + utilities	**TOTAL**	**Notes**
OPERATION			
Area Responsible	1	1	daily position
Assistant Area Responsible	1	1	daily position
Shift Superintendent	5	5	1 position per shift
Electrical Assistant	5	5	1 position per shift
Shift Supervisor	5	5	1 position per shift
Control Room Operator	5	5	1 position per shift
Field Operator	5	5	1 position per shift
Subtotal		**27**	
MAINTENANCE			
Mechanical group	3	3	daily position
Instrument group	3	3	daily position
Electrical group	3	3	daily position
Subtotal		**9**	
LABORATORY			
Superintendent+Analysts	2	2	daily position
Subtotal		**2**	
TOTAL		**38**	

Cost for personnel

Yearly individual average cost =	60,000	Euro/year
Total cost =	2,280,000	Euro/year

Steam reformer + CO2 capture				
	SR + utilities	**CO2 capture**	**TOTAL**	**Notes**
OPERATION				
Area Responsible	1		1	daily position
Assistant Area Responsible	1		1	daily position
Shift Superintendent	5		5	1 position per shift
Electrical Assistant	5		5	1 position per shift
Shift Supervisor	5		5	1 position per shift
Control Room Operator	5	5	10	2 positions per shift
Field Operator	5		5	1 position per shift
Subtotal			**32**	
MAINTENANCE				
Mechanical group	3		3	daily position
Instrument group	3		3	daily position
Electrical group	3		3	daily position
Subtotal			**9**	
LABORATORY				
Superintendent+Analysts	2		2	daily position
Subtotal			**2**	
TOTAL			**43**	

Cost for personnel

Yearly individual average cost = 60,000 Euro/year

Total cost = 2,580,000 Euro/year

Annual Maintenance Cost

A precise evaluation of the cost of maintenance would require the breakdown of the cost amongst the numerous components and packages of the plant. Since these costs are all strongly dependent on the type of equipment selected and their corresponding statistical maintenance data provided by the selected vendors, this type of evaluation of the maintenance cost is considered pre-mature for this level of study.

For this reason, the annual maintenance cost of the plant is estimated as a percentage of the Total Plant Cost of each cases. 1.5% of the TPC is assumed and this generally applied to each individual processes and utility units.

In general, estimates can be separately expressed as maintenance labour and maintenance materials. The maintenance labour to materials ratio of 40:60 can be statistically considered for this breakdown.

The yearly maintenance cost for all the cases evaluated in this study is reported in the table below (this is estimated with reference to year 2014).

Revision:	1
Date:	June 2015
Issued by:	NF
Approved by:	GC

Maintenance Costs (2014)

Case	Maintenance %	TPC €	Maintenance €/year
Base case	1,5	170.952.000	2.564.280
Case 1A	1,5	201.804.000	3.027.060
Case 1B	1,5	228.480.000	3.427.200
Case 2A	1,5	226.068.000	3.391.020
Case 2B	1,5	241.440.000	3.621.600
Case 3	1,5	305.328.000	4.579.920

Other Fixed Cost

The other fixed cost includes local taxes and fees, and insurance cost. This study assumed that the other fixed cost could be covered by 1% of the TPC.

8.2.3. *Summary of Results – Annual O&M Cost*

The table below summarises the annual O&M cost for the different cases.

	Revision	0	1	2	
	Date	May-2015	Jun-2015	Dec-2016	
	Issued by:	NF	NF	SS	
	Approved by:	GC	GC	SS	

ANNUAL O&M COST

	Base Case €/year	Case 1A €/year	Case 1B €/year	Case 2A €/year	Case 2B €/year	Case 3 €/year
Fixed Costs						
Direct labour	2,280,000	2,580,000	2,580,000	2,580,000	2,580,000	2,580,000
Adm./gen. overheads	991,714	1,137,247	1,185,264	1,180,922	1,208,592	1,323,590
Insurance & local taxes	1,709,520	2,018,040	2,284,800	2,260,680	2,414,400	3,053,280
Maintenance	2,564,280	3,027,060	3,427,200	3,391,020	3,621,600	4,579,920
Sub-total	7,545,514	8,762,347	9,477,264	9,412,622	9,824,592	11,536,790
Variable Costs (Availability - 95%)						
Feedstock & fuel	70,965,387	73,281,851	77,393,826	73,899,460	70,804,450	77,962,676
Raw water (make-up)	99,365	101,861	128,658	101,362	99,365	70,071
Chemicals & catalysts	420,000	420,000	505,000	420,000	420,000	420,000
Sub-total	71,484,752	73,803,712	78,027,484	74,420,822	71,323,814	78,452,748
Total Fixed & Variable Cost	79,030,265	82,566,059	87,504,748	83,833,444	81,148,406	89,989,538
Other Revenues						
Electricity Export / Import	-6,603,008	-993,314	-1,026,602	712,363	-189,076	-283,614
Other Cost						
CO2 Transport & Storage	-	3,877,737	4,908,973	3,791,720	3,569,042	6,661,077
Annual O&M Cost	**72,427,258**	**85,450,483**	**91,387,119**	**88,337,527**	**84,528,373**	**96,367,002**

8.3. Estimating the Levelised Cost of Hydrogen (LCOH) & CO_2 Avoidance Cost (CAC)

8.3.1. *Objective of the Economic Modelling*

The economic modelling is a simplified financial analysis that estimates, for each cases, the Levelised Cost of Hydrogen (LCOH) and the CO_2 Avoidance Cost (CAC), based on specific macro-economic assumptions.

The method of calculation is based on a discounted cash flow analysis. This is similar to how the Levelized Cost of Electricity (LCOE) are calculated in other IEAGHG studies, except that it also takes into account the revenues from the sale of electricity as co-product.

The LCOH predictions are estimated by obtaining a zero Net Present Value (NPV) for the project, corresponding to an Internal Rate of Return (IRR) equal to the Discount Rate (DR).

Therefore, the financial analysis is a high-level economical evaluation only, while the rigorous project profitability for the specific case is beyond the scope of the present study.

8.3.2. Levelised Cost of Hydrogen (LCOH)

The Cost of Hydrogen (COH) production is defined as the selling price at which hydrogen must be produced to reach the break even at the end of the plant lifetime for a targeted rate of return. However, for the purpose of screening the different technology alternatives, the levelised value of the cost of hydrogen (LCOH) is commonly preferred than the year-by-year data.

The Levelized Cost of Hydrogen (LCOH) is defined as the selling price of hydrogen which enables the present value from all sales of the product(s) over the economic lifetime of the plant to equal the present value of all costs of building, maintaining and operating the plant over its lifetime. In other word, the selling price of the product is calculated based on the assumption that NPV = 0 (over the whole life time of the plant).

In this type of analysis, the assumptions for the long-term inflation and the price/cost variations throughout the project life-time are not considered; therefore, the COH should be equal to the LCOH.

8.3.3. CO_2 Avoidance Cost (CAC)

The CO_2 Avoidance Cost (CAC) is calculated by comparing the costs and specific emissions of the plant with CCS with the cost and emissions of the reference case without CCS. For the hydrogen plant, it is defined as follows:

$$CO_2 \text{ Avoidance Cost (CAC)} = \frac{LCOH_{CCS} - LCOH_{Reference}}{CO_2 Emissions_{\ Reference} - CO_2 Emissions_{\ CCS}}$$

where:

- Cost of CO_2 avoidance is expressed in Euro per ton of CO_2
- LCOH is expressed in Euro per Nm^3 of H_2
- CO_2 emissions is expressed in tonnes of CO_2 per Nm^3 of H_2
- The selected reference case for the evaluation of the CAC is the Base Case, i.e. the conventional hydrogen plant without capture.

8.3.4. Macro-Economic Basis

The economic assumptions and macro-economic basis are reported in the Reference Document (see Annex I) of the report.

These mainly include:

- Reference dates and construction period,
- Financial leverage,
- Capital expenditure curve,
- Discount rate,
- Spare parts cost,
- Start-up cost,
- Owner's cost,
- Interests during construction,
- Working capital,
- Insurance cost,
- Local taxes and fees,
- Decommissioning cost.

The principal financial basis assumed for the financial modelling are reported also hereafter for reader's convenience:

ITEMS	DATA
Type of feedstock and fuel	Natural Gas at 6 €/GJ (LHV)
Discount Rate	8%
Capacity factor(*)	95%
EE selling price	80 €/MWh
CO_2 transport & storage cost	10 €/t STORED
CO_2 emission cost	0 €/t EMITTED
Inflation Rate	Constant Euro
Currency	Euro reported in 4Q2014

(*) 70% Capacity factor is assumed for Year 1.

8.3.5. Summary of Results – Financial Analysis

This section summarizes the results of the financial analysis performed for all the different cases of the study, based on the input data reported in the previous sections.

Table 3 reports the summary of the economical modelling results. Figure 1 and Figure 2 present the LCOH and CAC for all the study cases. The LCOH figures also show the relative weight of:

- Capital investment,
- Fixed O&M,
- Variable O&M
- Fuel,
- CO_2 transportation & storage.

For the cases with power export, the revenues from the electricity (EE) selling consequently reduces the LCOH. This effect is graphically shown in the LCOH figures starting from a negative value.

Table 3. Financial results summary: LCOH and CO_2 avoidance cost

Case	Description	LCOH c€/Nm^3	CAC €/t
Base Case	SMR w/o capture	11.4	-
Case 1A	CO_2 Capture from shifted syngas using MDEA	13.5	47.1
Case 1B	CO_2 capture from shifted syngas using MDEA with H_2 Rich Fuel Firing Burners	14.6	62.0
Case 2A	CO_2 Capture from PSA tail gas using MDEA	14.2	66.3
Case 2B	CO_2 Capture from PSA tail gas using Cryogenic and Membrane Technology	14.0	59.5
Case 3	CO_2 capture from flue gas using MEA	16.5	69.8

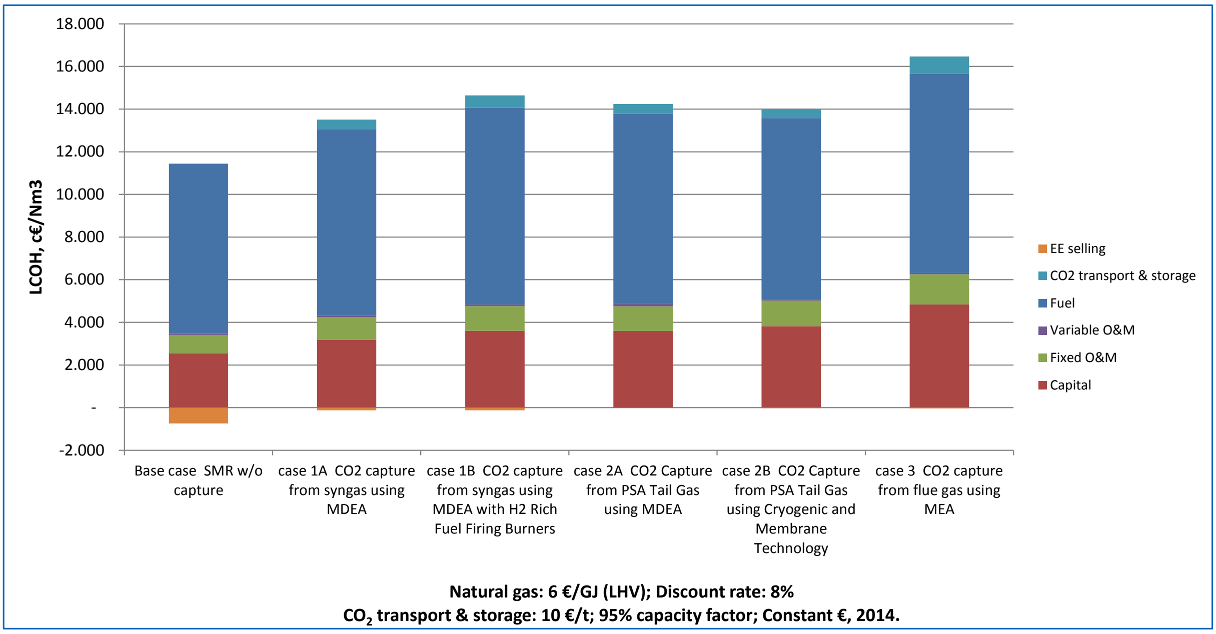


Figure 1. LCOH for the different study cases

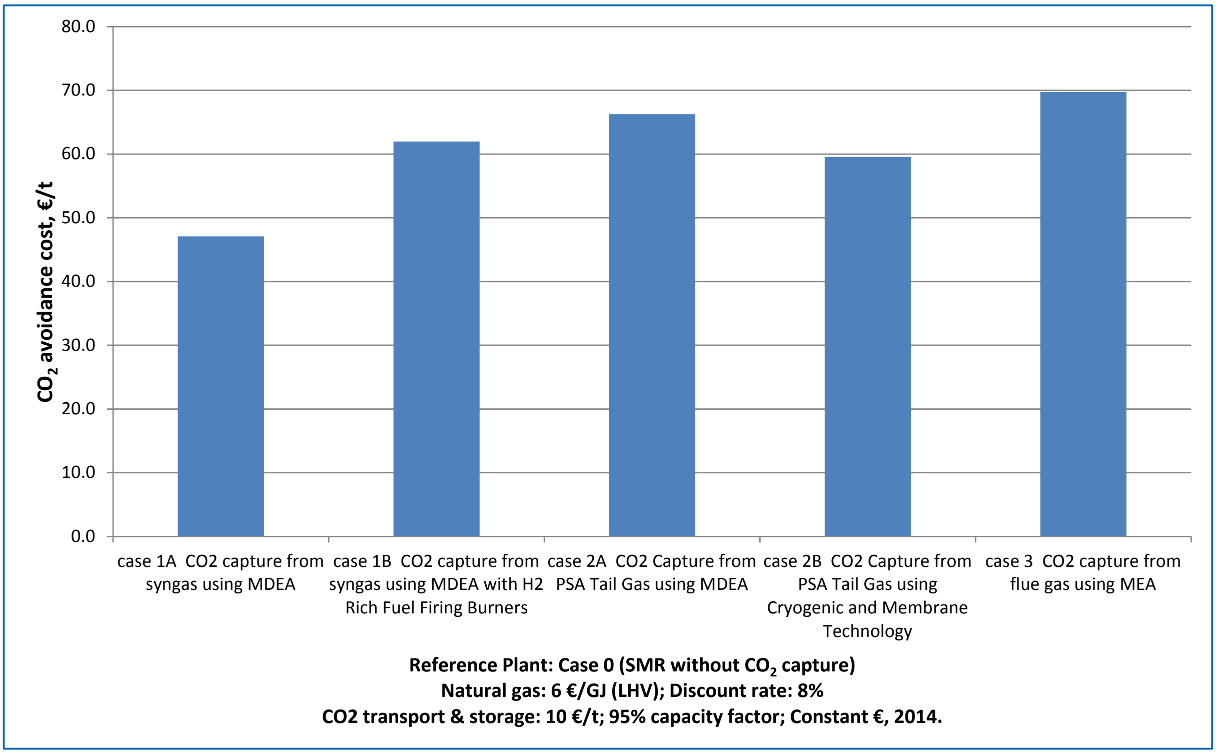


Figure 2. Cost of CO_2 avoidance for the study cases

8.4. Cost Sensitivity to the Main Financial Parameters

This section summarizes the results of the sensitivity analyses performed to estimate the LCOH and the CO_2 Avoidance Cost of the different study cases, versus the variation of the following economical parameters:

- Natural gas cost,
- EE selling / buying price
- Discount rate,
- CO_2 transport & storage cost,
- CO_2 emission cost,
- Plant life (project duration).

The sensitivity range has been selected in accordance to the study requirement, of which the following table below represents a summary.

Sensitivity relevant to all cases			
Criteria	**Unit**	**Base Number**	**Sensitivity Range**
Feedstock and fuel price	€/GJ (LHV)	6	2 to 18
EE selling / buying price	€/MWh	80	20 to 100
Discount rate	%	8	4 to 12
CO_2 transport & storage	€/t stored	10	-20 to 40
CO_2 emission costs	€/t emitted	0	0 to 100
Plant life	years	25	25 to 40

8.4.1. Sensitivity to the Natural Gas Price

LCOH

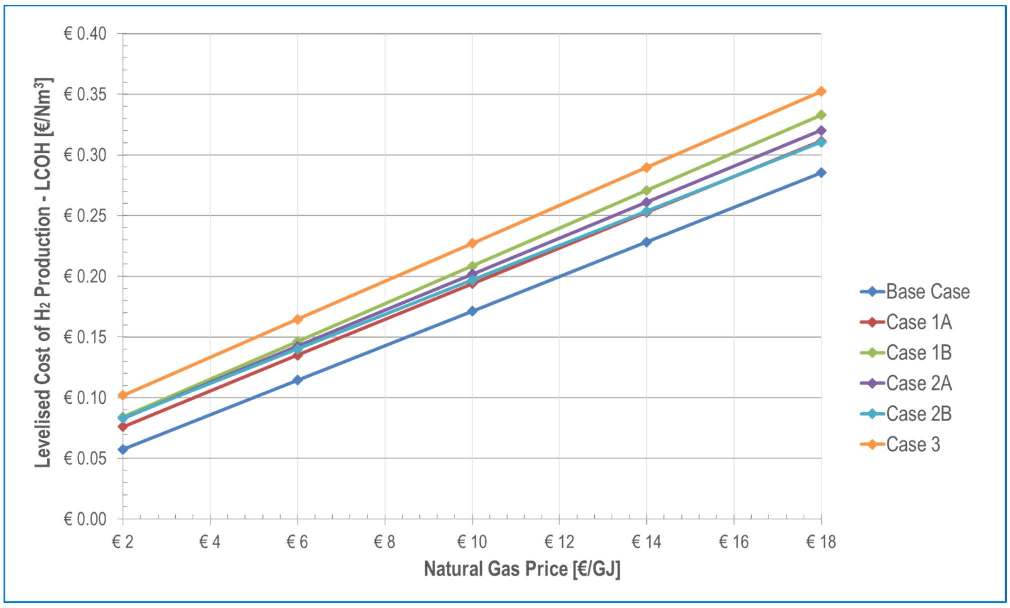


Figure 3. **LCOH sensitivity to the natural gas price**

CO_2 avoidance cost

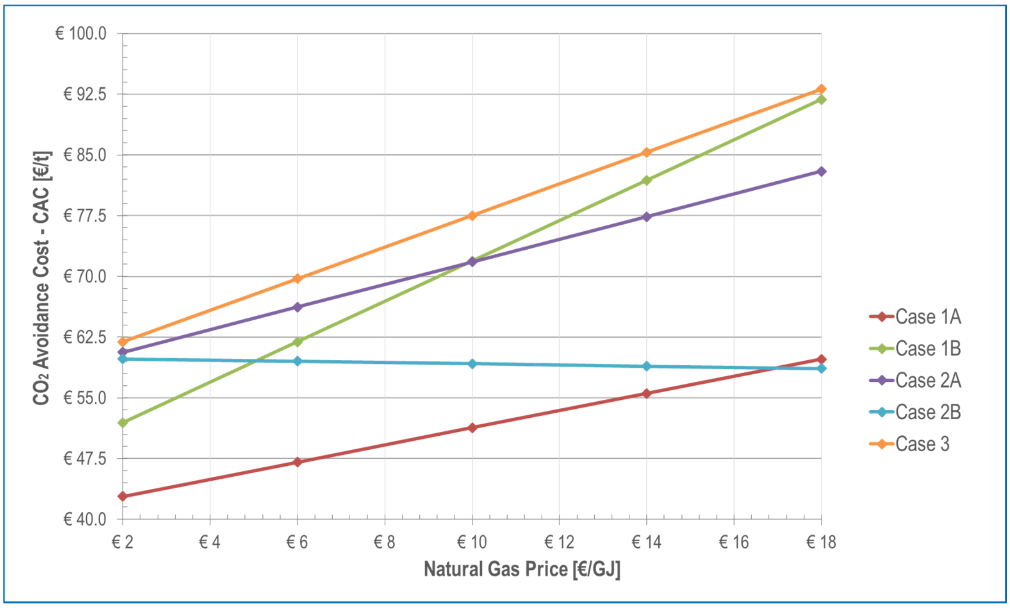


Figure 4. **Cost of CO_2 avoidance sensitivity to natural gas price**

8.4.2. Sensitivity to the Electricity (EE) Selling/Buying Price

LCOH

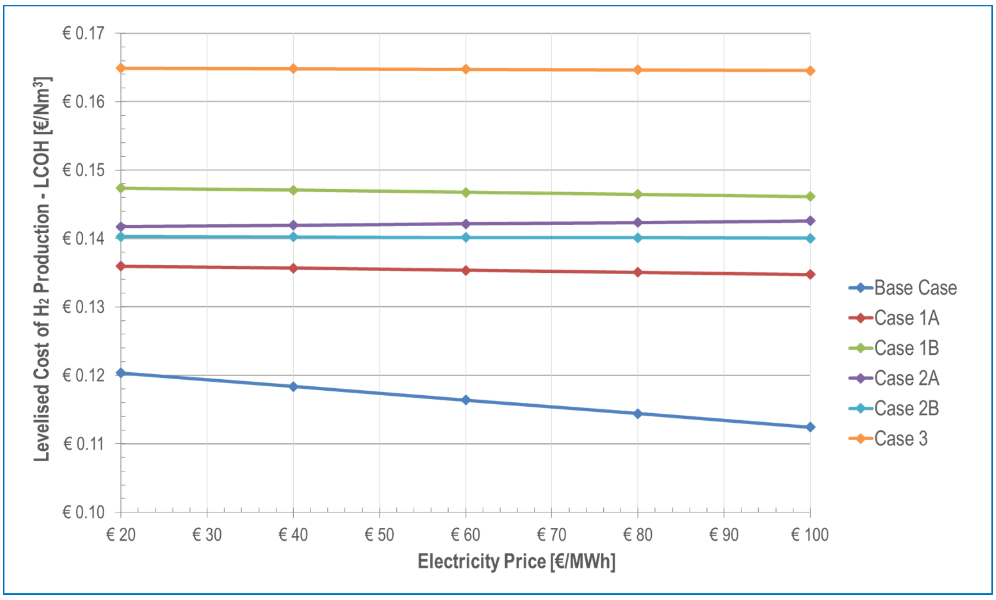


Figure 5. **LCOH sensitivity to EE selling/buying price**

CO_2 avoidance cost

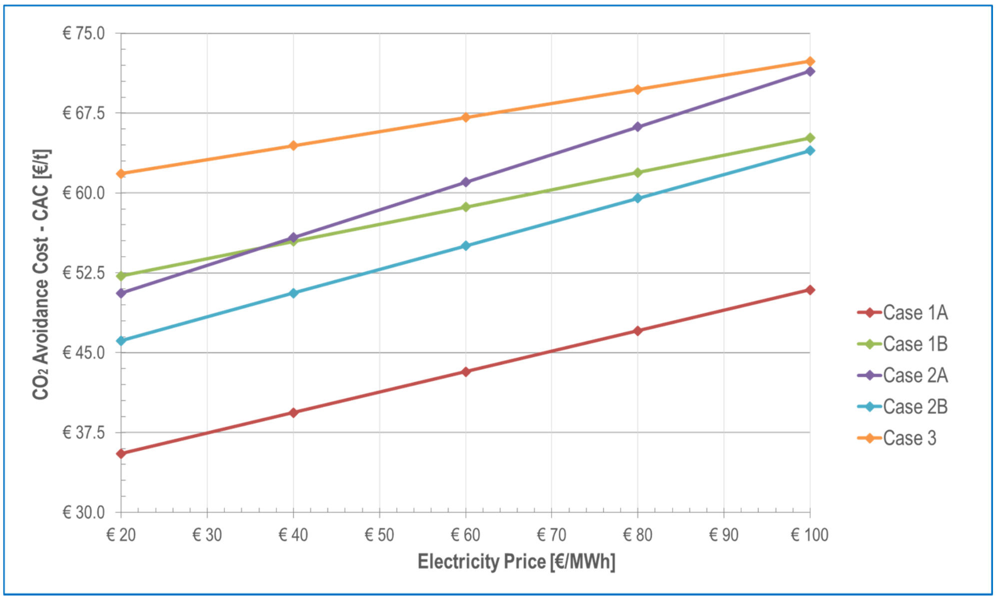


Figure 6. **Cost of CO_2 avoidance sensitivity to EE selling/buying price**

8.4.3. Sensitivity to the Discount Rate

LCOH

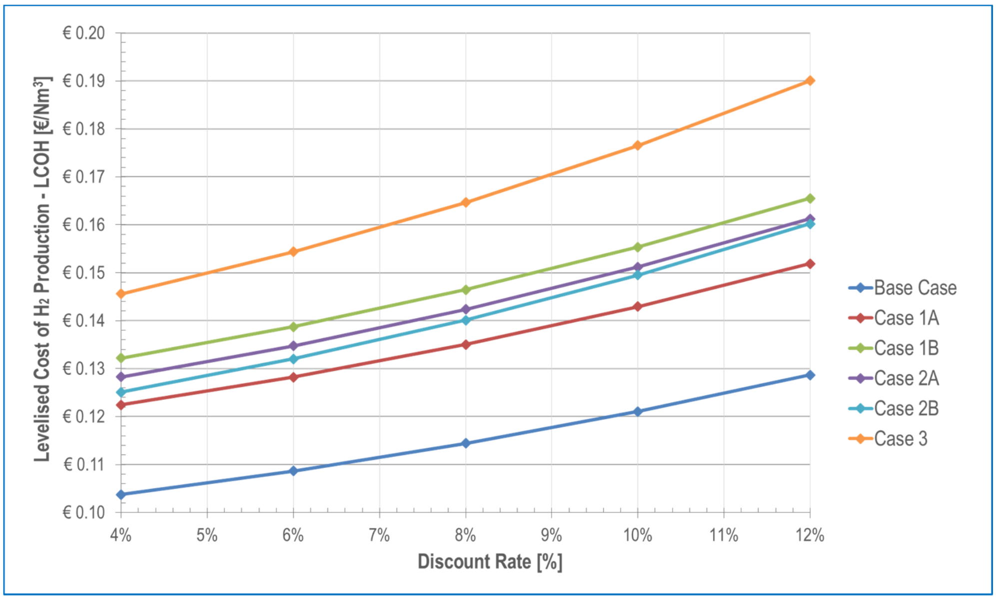


Figure 7. LCOH sensitivity to discount rate

CO_2 avoidance cost

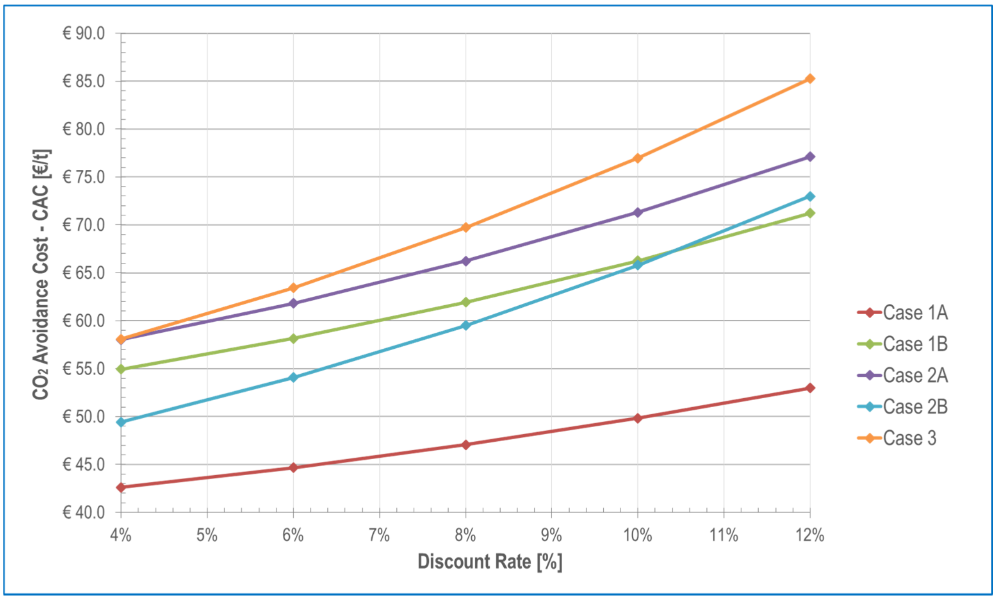


Figure 8. Cost of CO_2 avoidance sensitivity to discount rate

8.4.4. *Sensitivity to the CO_2 Transport & Storage Cost*

LCOH

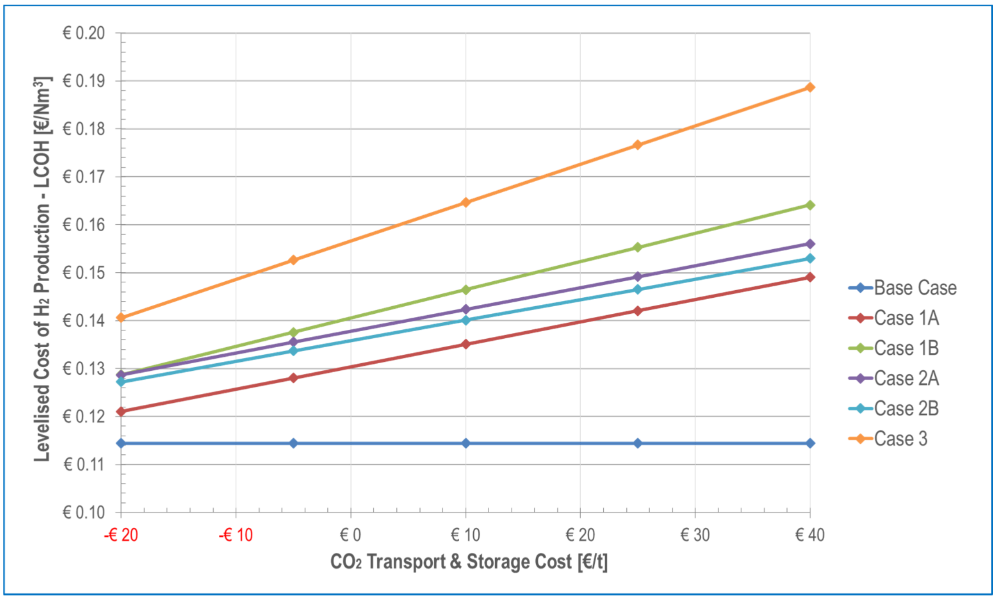


Figure 9. **LCOH sensitivity to CO_2 transport & storage cost**

CO_2 avoidance cost

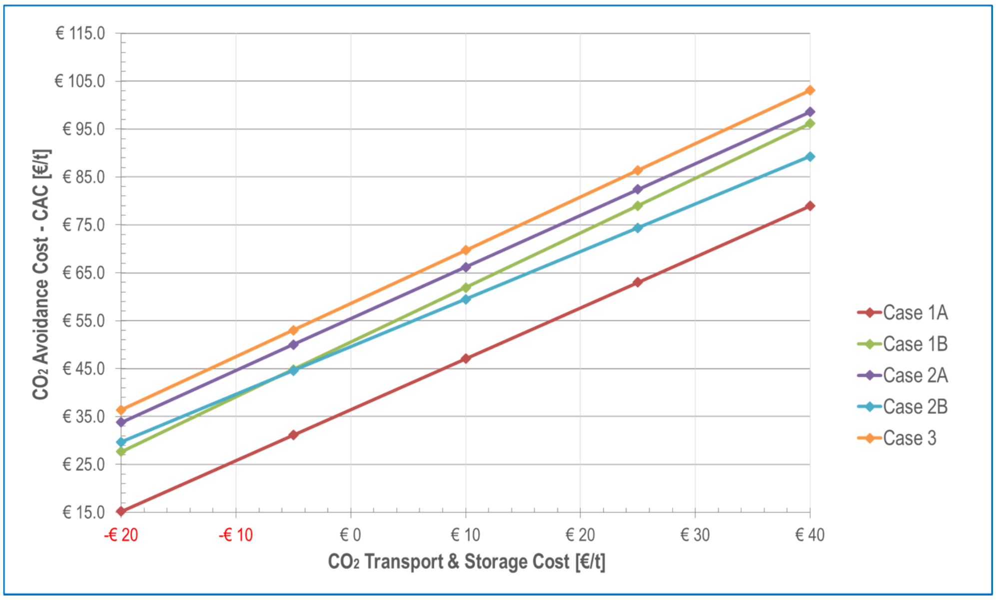


Figure 10. **Cost of CO_2 avoidance sensitivity to CO_2 transport & storage cost**

Note: Negative CO_2 transport and storage cost could represent income received from CCS operation (i.e. EOR revenues, any incentives or tax credits from authorities)

8.4.5. Sensitivity to the CO_2 Emissions Cost

LCOH

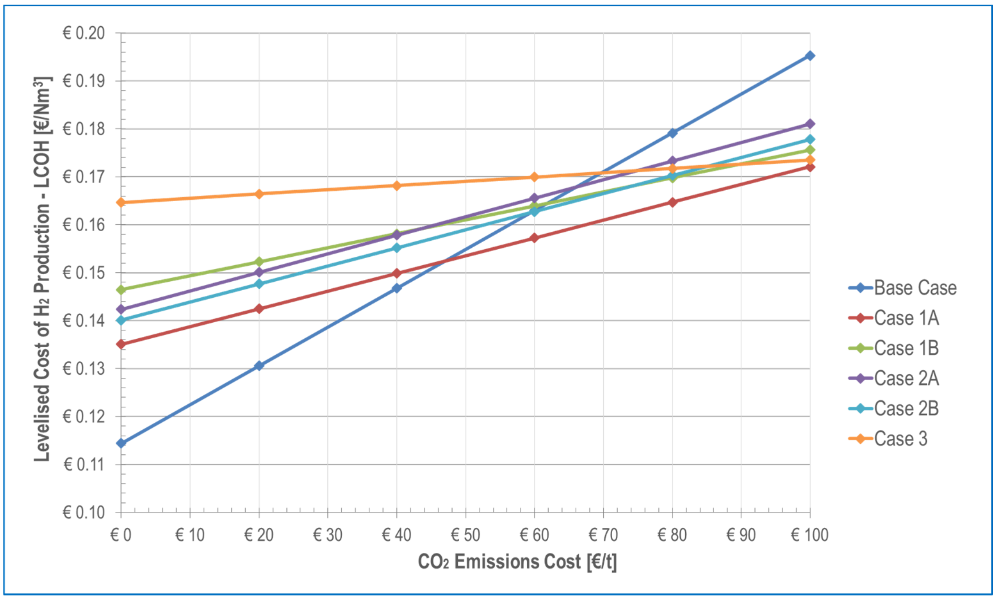


Figure 11. LCOH sensitivity to CO_2 emission cost

CO_2 avoidance cost

The CO_2 avoidance cost is expected to be neutral with the variation of CO_2 emissions cost.

Nonetheless, it is important to note that the CAC should be equal to zero at the point in the x-axis (CO_2 emissions cost) where the LCOH of H_2 plant with CCS intersect with the LCOH of H_2 plant without CCS. The CO_2 emissions cost at the intersection point for each case should be equal to the CAC values reported in Table 3 – see Sheet 99.

8.4.6. *Cost Sensitivity to the Plant's Economic Life*

LCOH

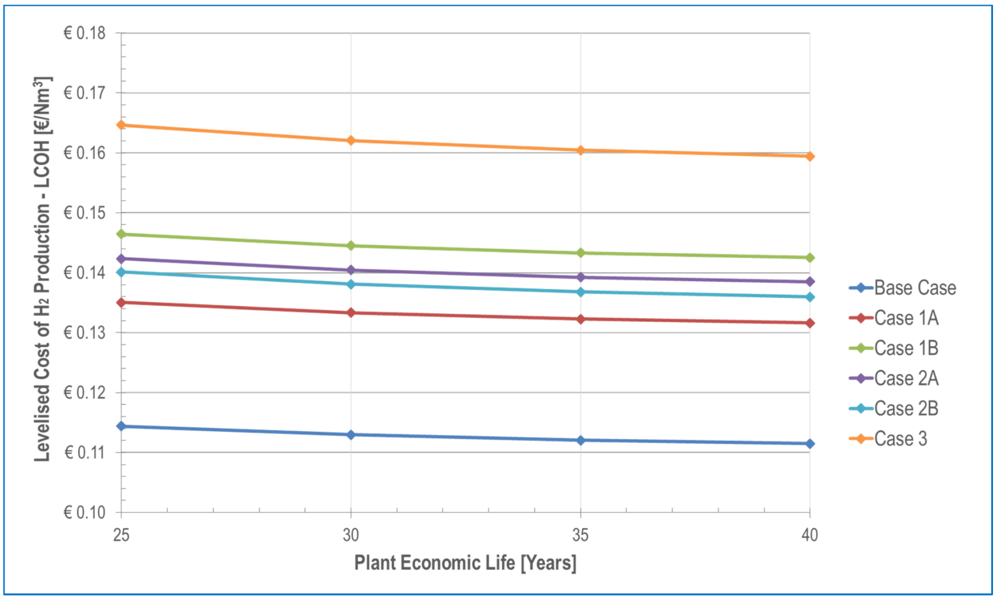


Figure 12. LCOH sensitivity to plant life

CO_2 avoidance cost

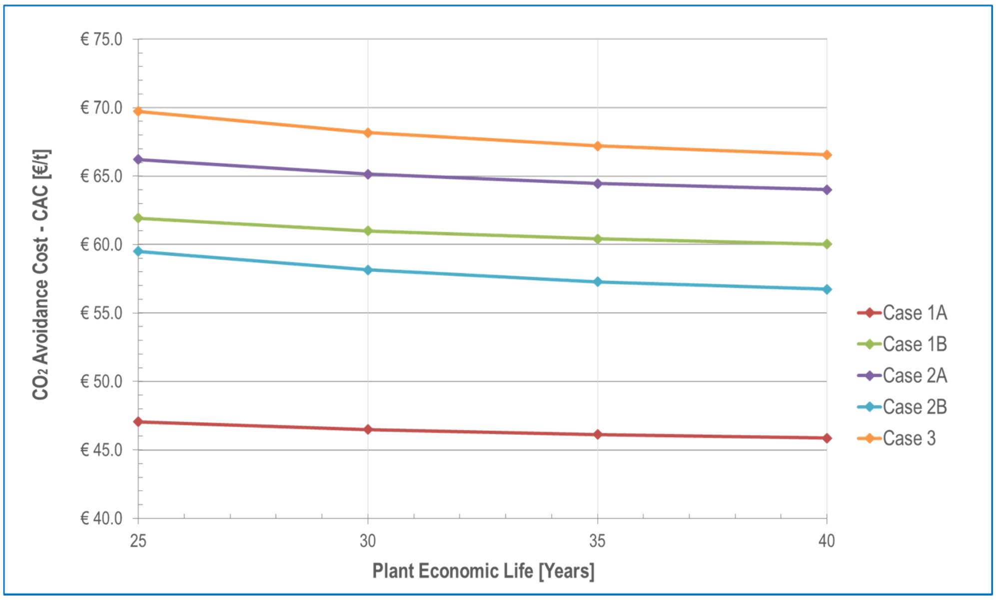


Figure 13. Cost of CO_2 avoidance sensitivity to plant life

Annex I:

Reference Document (Task 2): Criteria for Assessing the Techno-Economic Evaluation of H_2 or HYCO Plant

CLIENT : IEA Greenhouse Gas R&D Programme (IEAGHG)
PROJECT NAME : Techno-Economic Evaluation of H_2 Production with CO_2 Capture
DOCUMENT NAME : Reference Document
FWI Contract : 1BD0840A

ISSUED BY : G. AZZARO
CHECKED BY : G. COLLODI
APPROVED BY : G. COLLODI

DATE	REVISED PAGES	ISSUED BY	CHECKED BY	APPROVED BY

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1. Introduction

In the past years, IEA Greenhouse Gas R&D Programme (IEAGHG) has issued a series of reports presenting the performance and cost of CO_2 capture technologies when applied to energy intensive industries and these include cement, iron and steel, pulp and paper, oil refining, co-production of power and hydrogen from coal.

In line with the commitment to support and understand any development and deployment of low carbon energy technologies, IEAGHG has contracted Amec Foster Wheeler (Amec FW) to perform a study aiming to investigate the deployment of CO_2 capture technologies in a hydrogen production unit operating as standalone (merchant) or integrated to an industrial complex.

Hydrogen is used as feedstock to various industries. This could be delivered as nearly pure H_2 or as HYCO gas. Currently, nearly 95% of hydrogen generated industrially is consumed by ammonia production, oil refineries and other chemical industries (i.e basic chemicals, petrochemicals, oleo-chemicals etc...), and metal industries (i.e. direct iron reduction or DRI production).

Nearly 90% of the Hydrogen production from NG or other light hydrocarbon (HC) feedstock is produced from steam methane reforming (SMR). Other production routes include autothermal reforming (ATR) and partial oxidation (POX).

The leading technologies available for capturing CO_2 from H_2 plants include the use of chemical absorption technology (in post-combustion or pre-combustion options), cryogenic or low temperature separation technology, membrane, PSA and others.

This study mainly aims to evaluate performance and cost of capturing CO_2 from the shifted syngas, PSA tail gas or SMR's flue gas using chemical absorption technology (as applied to all the possible CO_2 capture schemes) or cryogenic and membrane separation technology (as applied to capturing of CO_2 from the PSA tail gas only).

One of the objectives of this study is aimed to develop a common methodology of assessing the techno-economics of H_2 production. As such, the scope of TASK 2 has been set to provide a "Reference Document" to serve as a good basis to develop the different assumptions (engineering and techno-economic parameters) that could be used in evaluating the levelised cost of H_2 production without and with CO_2 capture (for TASK 3); and the levelised cost of ammonia and methanol production without and with CO_2 capture (for TASK 4).

2. Definition of the Reference Document

The scope of the techno-economic assessment consists of the following:

- TASK 3 – evaluating the performance and cost of deploying CCS in a standalone (merchant) H_2 plant.
- TASK 4 – evaluating the performance and cost of deploying CCS in an SMR based HYCO plant integrated with ammonia/urea or methanol production complex.

The "Reference Document" describes the general plant design basis and cost estimating criteria which will be used as a common basis for the techno-economic evaluation of H_2 plant without and with CO_2 capture.

The design and economic criteria outlined in the following sections will be mainly used as a reference for developing the H_2 plant configurations (scope of TASK 3) to be analysed as part of the study.

Specific criteria for TASK 4 are presented in the final report of TASK 4, as applicable.

It should be noted that in TASK 4, additional CO_2 is specifically captured from the SMR's flue gas. For the ammonia case, part of the CO_2 captured from this source will be used to maximised the production of the urea.

Where relevant, information retrieved from IEAGHG document "Criteria for Technical and Economic Assessment of Plants with Low CO_2 Emissions" Version C-6, March 2014, are included.

2.1. Merchant Hydrogen Plant

For the scope of TASK 3, the plant scheme analysed in the study includes:

- Hydrogen Plant (with or without CO_2 capture) via SMR
- Cogen Plant
- Utility Plant

The hydrogen plant will produce H_2 as the main product and HP steam as co-product.

The HP steam will be used to fulfil power requirements of the H_2 Plant by driving a steam turbine (COGEN Plant).

Should the electricity produced within the plant not be sufficient to fulfil the H_2 plant needs, the following two options will be evaluated for supplying the additional power to the H_2 plant: (a.) power import from the grid, or (b.) power production inside the battery limit via gas fired boiler (to be confirmed over the course of the work).

2.2. HYCO Plant or Syngas Generation Unit

For the scope of TASK 4, the plant scheme analysed in the study includes:

- Primary reformer
- Secondary reformer
- Associated syngas processing units
- Ammonia/urea or methanol synthesis plant

For the plants without CO_2 capture, the HP and MP steam produced in the syngas generation section and the synthesis section are mainly used to drive various turbo-machineries.

The electricity required by the plants without and with CCS are imported from the grid. The indirect CO_2 emission from the electricity will be accounted for by assuming that electricity is coming from an NGCC or USCPC power plants (without CCS).[1]

2.2.1. Ammonia/Urea Production

The HYCO plant for the ammonia/urea production consists of the SMR based primary reformer in tandem with the air blown autothermal reformer to produce a raw syngas (containing mainly CO_2, CO, CH_4, H_2 and N_2).

The raw syngas is then processed in the following units:

- Syngas cooling
- High and low temperature shift reactors
- Bulk CO_2 removal unit
- Methanation reactor
- Syngas compressor

This produces the product syngas (mainly containing H_2, N_2 with small amount of CH_4) used in the ammonia synthesis plant. The ammonia is then fed into the urea synthesis plant together with the CO_2 from the bulk removal unit.

The ammonia/urea plant produces granulated urea as the main product with chilled ammonia as co-product (for the Base Case only).

[1] CO_2 emissions from the NGCC or USCPC will be based on the information from previous IEAGHG studies:

- IEAGHG Report No. 2014-03 "CO_2 Capture at Coal Based Power and Hydrogen Plant"
- IEAGHG Report No. 2015-05 "Oxy-Combustion Turbine Power Plants"

2.2.2. Methanol Production

The HYCO plant for the methanol production consists of the SMR based primary reformer in tandem with the oxygen blown autothermal reformer to produce a raw syngas (containing mainly CO_2, CO, CH_4, and H_2).

The raw syngas is then processed in the following units:
- Syngas cooling
- Syngas compressor

This product syngas (mainly containing CO_2, CO, H_2 with small amount of CH_4) is used as the make-up gas or MUG of the methanol synthesis plant.

The methanol plant only produces AA grade methanol as the main product.

3. General Data and Technical Assumptions

This section summarizes the general plant design criteria and assumptions used as a common basis for the design of the SMR based H_2 or HYCO plant with and without CO_2 capture.

3.1. Plant Location

The plant is situated at a greenfield site located at the North East coast of The Netherlands, with no major site preparation required. There will be no restrictions on plant area and no special civil works or constraints on the delivery of equipment are assumed. Rail lines, roads, fresh water supply and high voltage electricity transmission lines, high pressure natural gas pipeline are considered available at plant battery limits.

3.2. Climatic and Meteorological Data

Main climatic and meteorological data are listed below. Conditions marked (*) are considered reference conditions for the plant performance evaluation.

- Atmospheric pressure 101.3 kPa (*)
- Relative humidity
  - Average 80% (*)
  - Maximum 95%
  - Minimum 40%
- Ambient temperatures
  - minimum air temperature -10°C
  - maximum air temperature 30°C
  - average air temperature 9°C (*)

3.3. Feedstock Specification

3.3.1. Natural Gas

Natural gas is used as the main feedstock and fuel to the H_2 or HYCO plant and delivered to the plant battery limits from a high pressure pipeline.

The specifications of the natural gas are shown in the table below.

Table 1. Natural Gas Specifications

Natural Gas Analysis (vol%)	
Methane	89.0
Ethane	7.0
Propane	1.0
Butane	0.1
Pentane	0.01
Carbon Dioxide	2.0
Nitrogen	0.89
Sulphur (as H_2S)	5 ppmv*
Total	100.00

HHV (MJ/kg)	51.473
LHV (MJ/kg)	46.502

Conditions at plant B.L.	
Pressure, MPa	7.0

*5 ppm_v of H_2S are assumed to be present in the natural gas for design purposes

3.4. Products and Co-Products

The main products and co-products of the Hydrogen Plant analysed in TASK 3 of this study are listed in this section, together with their main specifications.

The main products of the Ammonia/Urea and Methanol Plants analysed in this study are presented in the TASK 4 final report.

3.4.1. Hydrogen

The specification for the hydrogen used in the analysis are presented in Table 2.

The syngas or HYCO gas used in the ammonia or methanol synthesis are specified in the TASK 4 report. The pressure at the B.L. of the Syngas Generation Section is dependent on the requirement of the industrial complex.

Table 2. Hydrogen Specifications

H_2	99.5%v (min.)
$CO + CO_2$	10 ppm (max.)
CO	10 ppm (max.)
H_2S, HCl, COS, HCN, NH_3	Free
N_2 + Ar	Balance

LHV	119.96 MJ/kg
HHV	141.88 MJ/kg

Pressure at B.L.*	2.5 MPa
Temperature at B.L.	40°C

* This is the pressure at the B.L. (to be assumed for TASK 3 evaluation).
It should be noted that this is the pressure of the H_2 product from the PSA (i.e. without any H_2 compressor)

3.4.2. Carbon Dioxide

The specifications of the CO_2 as delivered from the plant's B.L. to the pipeline are presented Table 3.

Table 3. Product CO_2 Specifications

Maximum allowable impurities in the product CO_2 [(1)]	
H_2	4% [(2,4)]
N_2 + Ar	4% [(3,4)]
O_2 [(5)]	100 ppm[(4,6)]
CO	0.2% [(7)]
H_2S	20 ppm[(8)]
H_2O	50 ppm [(9)]

Pressure at B.L.*	11 MPa
Temperature at B.L.	30°C

(1) Based on information available in 2012 on the requirements for CO_2 transportation and storage in saline aquifers
(2) Hydrogen concentration to be normally lower to limit loss of energy and economic value. Further investigation is required to understand hydrogen impact on supercritical CO_2 behaviour.
(3) The limit on concentrations of inerts are to reduce the volume for compression, transport and storage and limit the increase in Minimum Miscibility Pressure (MMP) in Enhanced Oil Recovery (EOR).
(4) Total non-condensable content (N_2 + O_2 + H_2 + CH_4 + Ar): maximum 4% vol. basis. This is based on the recommendations reported in the ENCAP Project (http://www.encapCO2.org)
(5) Oxygen content should be specified in conjunction with water content to limit corrosion in the downstream infrastructure.
(6) Oxygen limit is considered tentative due to the lack of practical experience on the operation of the CO_2 storage infrastructure. It is expected that stringent limit will be in place for EOR operation.
(7) CO limits are set from a health and safety perspective.
(8) H_2S specification should be specified in conjunction with water content to limit corrosion in the downstream infrastructure.
(9) Water specification is to ensure there is no free water and hydrate formation.

3.4.3. HP Steam

Refer to Section 3.11.4

3.4.4. Electric Power

High voltage grid connection: 380 kV
Frequency: 50 Hz

3.5. Environmental Limits

The environmental limits set up for each cases are outlined in this section.

3.5.1. Gaseous Emissions

The overall gaseous emissions from the plant should not exceed the following limits:

NO_x (as NO_2)*	$\leq$ 120 mg/Nm^3
SO_x (as SO_2)*	N.A.**
CO	$\leq$ 30 mg/Nm^3

* Emission expressed in mg/Nm^3 @ 3% O_2, dry basis.
** SOx will be very minimal – given that the PSA tail gas is expected to be sulphur free and NG as supplementary fuel contains only less than 5 ppm_v.

3.5.2. Liquid Effluent Discharge

Characteristics of waste water discharged from the plant should comply with the standard limits required by the EU directives currently in force.

The main liquid effluent that continuously flows out of the B.L. is coming from the blow-down of the steam drum (in the Deaerator section of the BFW system).

Sea water used in the primary cooling system is returned to the sea with allowable maximum temperature increase of 7°C.

3.5.3. Solid Wastes Disposal

Solid wastes from the Hydrogen Plant consists of the spent catalysts. All solid wastes will be handled in accordance to the instruction and guidelines provided by the catalyst vendors and the plant owner's established procedure.

The spent catalysts collected from the plant are in their oxidized/inert state; as such, these are considered non-hazardous.

The reformer's and pre-reformer's catalyst contains nickel, which can often be recovered. The other spent catalyst would normally be disposed of in the landfill.

3.5.4. Noise Pollution

All the equipment of the plant are designed to obtain a sound pressure level of 85 dB(A) at 1 meter from the equipment.

3.6. Key Features of the Hydrogen Production Plant

This key features of the SMR based Hydrogen Plant considered for TASK 3 are presented in this section of the report.

The key features of the Syngas Generation or HYCO plant considered for the ammonia and methanol production are specified in the Final Report of TASK 4.

3.6.1. Capacity

The plant capacity is assumed contact for all cases producing 100,000 Nm^3/h of high purity Hydrogen.

3.6.2. Configuration

The hydrogen production plant consists of one train and integrates the following sections:

- Feed Pre-treatment
- Pre-reforming
- Primary Reforming
- Water Gas Shift Conversion
- Final Hydrogen Purification (based on PSA)
- Steam and BFW System
- CO_2 Capture System (only for CO_2 capture cases)
- CO2 Compression and Dehydration (only for CO_2 capture cases)

3.6.3. Plant Turndown

The minimum turndown of the hydrogen plant considered in this study is assumed at 40%.

For TASK 4, the minimum turndown is dependent on the chemical complex it is integrated with.. However, it is expected that high availability is required for the syngas or HYCO production to meet the demand of the chemical production operation. Nonetheless, in typical normal operation, 40% turn down for the SMR should be necessary during start-up or upset within the chemical complex (hence reducing natural gas consumption during these events).

3.7. Capacity Factor

The table below presents the expected capacity factor (average yearly capacity factor) of the hydrogen plant evaluated in TASK 3.

Plant	Year	Average capacity factor
H_2 Production	1st year of operation	70%
	2nd – 25th year of operation	95%

The capacity factor of 90% will be assumed for the ammonia/urea and methanol production complex evaluated in TASK 4.

3.8. Process and Utility Units

This section summarised the different unit processes and utilities included in the B.L. of the hydrogen plant considered for TASK 3.

Process Units

- Feed Pre-treatment
- Pre-reforming
- Primary Reforming
- Water Gas Shift conversion
- Final Hydrogen purification (PSA)
- Steam and BFW system
- CO_2 capture system (only for CO_2 capture cases)
- CO_2 compression (only for CO_2 capture cases)

Utilities and Offsite Units

- Cooling water
- Demineralised, Condensate recovery Water Systems
- Plant/Instrument Air Systems
- Inert gas System
- Fire Fighting System
- COGEN Plant (import/export, depending on cogeneration option considered)
- Chemicals
- Flare system
- Interconnecting

The different unit processes and utilities of the ammonia/urea and methanol production complex are presented in the Final Report of TASK 4.

3.9. Units of Measurement

The units of measurement used in this study are in SI units.

3.10. Plant's Battery Limits

The plant's battery limits are defined in the Final Report of TASK 3 and TASK 4.

3.11. Utility and Service Fluids Characteristics/Conditions

The following sections present the main utilities and service fluids used within the hydrogen or HYCO plant.

3.11.1. Cooling Water

The cooling water system is based on once through seawater cooling for the primary system and close circuit demi-water cooling for the secondary system.

Primary System – Seawater Cooling Specifications

Source	:	sea water in once through system
Service	:	for steam turbine condenser and CO2 compression unit.
Type	:	clear filtered and chlorinated, without suspended solids and organic matter.
Salinity	:	22 g/l

Supply temperature:

- average supply temperature (on yearly basis): 12°C
- max supply temperature (average summer): 14°C
- min. supply temperature (average winter): 9°C
- max. allowable seawater temperature increase: 7°C

Return temperature:

- average return temperature: 19°C
- max return temperature: 21°C

Design temperature: 50°C
Operating pressure at condenser inlet: 0.05 MPa(g)
Design pressure: 0.4 MPa(g)
Max allowable ΔP for Users: 0.05MPa(g)
Turbine condenser minimum ΔT: 5°C*
Turbine condenser conditions

- Temperature 28°C*
- Pressure 0.0038 MPa*

Secondary System: Closed Circuit Demineralised Water (Demi-Water) Cooling

Source	:	demineralised water stabilized & conditioned – seawater cooled
Service	:	for machinery cooling and for all plant users other than steam turbine condenser and CO_2 compression exchangers

Supply temperature:

- average supply temperature	19°C
- max. supply temperature:	21°C
- max. allowable temperature increase:	11°C

Design temperature:	50 °C
Operating pressure at Users:	0.3 MPa(g)
Design pressure:	0.7 MPa(g)
Max. allowable ΔP for Users:	0.15 MPa(g)

3.11.2. Air Cooling System

Air temperature to be considered for the air cooler design is set at 25 °C.

3.11.3. Demineralised Water (Demi-Water)

Type:		Treated raw water
Operating pressure at grade (min):		0.5 MPa(g)
Design pressure:		0.95 MPa(g)
Operating temperature:		Ambient
Design temperature:		38°C
Specifications:		
- pH		6.5÷7.0
- Total dissolved solids	mg/kg	0.1 max
- Conductance at 25°C	µS	0.15 max
- Iron	mg/kg as Fe	0.01 max
- Free CO_2	mg/kg as CO_2	0.01 max
- Silica	mg/kg as SiO_2	0.015 max

3.11.4. Steam Conditions

The conditions for the HP and LP steam used in the evaluation for the Hydrogen Plant in TASK 3 are summarised below.

Table 4. Steam Conditions used by the Process Units

Steam (at Process Unit's B.L.)	Pressure - MPa(g)				Temperature - °C			
	min	normal	max	design	min	normal	max	design
HP Steam	3.92	4.13	4.21	4.68/FV	375	395	405	425
LP Steam	0.31	0.34	0.37	0.63/FV	150	177	180	210

The conditions for the HP, MP and LP steam used in the evaluation for the Ammonia/Urea and the Methanol Production Complex are presented in the Final Report of TASK 4.

3.11.5. Instrument and Plant Air Specifications

Instrument Air

Operating pressure
- normal: 0.7 MPa(g)
- minimum: 0.5 MPa(g)

Design pressure: 1 MPa(g)
Operating temperature (max): 40°C
Design temperature: 60°C
Dew point @ 0.7 MPa(g): -30°C

Plant Air

Operating pressure: 0.7 MPa(g)
Design pressure: 1MPa(g)
Operating temperature (max): 40°C
Design temperature: 60°C

3.11.6. Nitrogen

Low Pressure Nitrogen
Supply pressure: 0.65 MPa(g)
Design pressure: 1.15 MPa(g)
Supply temperature (min): 15°C
Design temperature: 70°C
Min Nitrogen Purity: 99.9 % vol. (instrument grade)

3.11.7. Chemicals

The chemicals used in the Hydrogen (TASK 3) or HYCO (TASK 4) generally consists of the additives used in treating boiler feed water and condensates. For example:

- Oxygen scavenger: Nalco Elimin-OX 100%, or equivalent,
- Phosphate injection: Water solution with 50% Na_2HPO_4 and
- pH control injection: Morpholine (100%)

Design pressure: atmospheric pressure plus full tank of liquid solution
Design temperature: 80°C

3.12. Codes and Standards

The design of the process and utility units are in general accordance with the main International and EU Standard Codes.

3.13. Software Codes

For the design of the plant, three software codes have been mainly used to evaluate the heat and mass balances of the different study cases:

- PROMAX v3.2 (by Bryan Research & Engineering Inc.): Simulation of the CO_2 capture from the shifted syngas, PSA tail gas or SMR's flue gas using amine sweetening process.
- Aspen HYSYS v7.3 (by AspenTech): Simulation of the SMR based hydrogen or HYCO plant and the CO_2 compression and dehydration unit.
- Gate Cycle v6.1 (by General Electric): Simulation of the Power Island used by the Steam Turbine and the Preheating Line of the condensate and BFW.

4. Criteria for Economic Evaluation

The following sections describe the main bases in estimating the cost or criteria used in the economic assessment of the H_2 or HYCO plants (without and with CO_2 capture).

4.1. Economic Criteria

4.1.1. Plant Economic Life

The plant is designed for 25 years life.

4.1.2. Project Schedule

Project start		2016
Plant operation start		2019
Investment phase duration	(years)	3
Plant operating life	(years)	25
Plant operation end		2043

4.1.3. Total Capital Requirement

The Total Capital Requirement (TCR) includes:

- Total Plant Cost (TPC)
- Spare parts cost
- Start-up costs
- Owner's costs.
- Interest during construction
- Working capital

The estimates are quoted in euros (€), based on 4Q 2014 price level.

4.1.4. Total Plant Cost

The Total Plant Cost (TPC) is the installed cost of the plant including contingencies. The estimates are broken down into the main process units and, for each cases and further split into the following items:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency

4.1.5. *Estimate Accuracy*

The accuracy of the estimates are in the range of +35%/-15% (which in accordance to AACE Class 4 specification).

4.1.6. *Contingency*

The project contingency is added to the capital cost to give a 50% probability of a cost over-run or under-run.

For the accuracy considered in this study, 20% of the TPC is assumed for all the different units of the plant.

4.1.7. *Design and Construction Period*

Plant design and construction period and the curve of capital expenditure during construction are defined as follows:

- Construction period(1) 3 years
- Capital Expenditure Curve

Year	Investment Cost %
1	20
2	45
3	35

(1) Note: Starting from issuance of the "Notice to Proceed" to the EPC contractor

4.1.8. *Financial Leverage (Ration of Debt / Invested Capital)*

All the capital requirements are treated as debt, i.e. the financial leverage equal to 100%.

4.1.9. *Interests during Construction*

Interest during construction is calculated from the plant construction schedule and interest rate is assumed same as the discount rate.

Expenditure is assumed to take place at the end of each year and interest during construction payable in a year is calculated based on money owed at the end of the previous year.

4.1.10. Discount Rate

The analysis is based on Discounted Cash Flow analysis. The discount rate of 8% is assumed.

4.1.11. Inflation Rate

Not considered. Real constant money is assumed in all the calculation.

4.1.12. Depreciation

Not considered. The results are reported on the Earnings Before Interest, Taxes, Depreciation and Amortisaton (EBITDA) basis.

4.1.13. Spare Parts Cost

0.5% of the TPC is assumed to cover spare part costs. It is assumed that spare parts have no value at the end of the plant life due to obsolescence.

4.1.14. Start-Up Cost

Start-Up cost consists of:

- 2% of the TPC, to cover modifications to equipment that needed to bring the unit up to full capacity.
- 25% of the full capacity feedstock and fuel cost for one month, to cover any inefficient operation that occurs during the start-up period.
- Three months of operating labour and indirect labour cost and the maintenance labour cost, to include training.
- One month of chemicals (including solvent for CO_2 capture if applicable), catalysts, and waste disposal costs and the maintenance materials cost.

4.1.15. Owner's cost

7% of the TPC is assumed to cover the Owner's cost and fees.

The Owner's cost covers the expenditure related to the feasibility studies, land surveys, land purchase, construction or improvement to roads and railways, water supply, other infrastructures, etc… beyond the site boundary, owner's engineering staff costs, permitting and legal fees, arranging financing and other miscellaneous costs.

The Owner's costs are assumed to incur in the first year of construction, allowing for the fact that some of the costs would be incurred before the start of construction.

4.1.16. Working Capital

Working capital includes inventories of fuel and chemicals (materials held in storage outside of the process plants). Storage for 30 days at full load is considered for chemicals and consumables.

It is assumed that cost of these materials is recovered at the end of the plant life.

The study also assumed a zero balance for both Trade Debtors and Trade Creditors.

4.1.17. Insurance Cost

0.5% of the TPC is assumed to cover the plant's insurance cost.

4.1.18. Local Taxes and Fees

Another 0.5% of the TPC is assumed to cover the local taxes and fees.

4.1.19. Decommissioning Cost

The salvage value of equipment and materials is normally assumed to be equal to the costs of dismantling and site restoration, resulting in a zero net cost of decommissioning.

4.2. Annual Operating and Maintenance Cost

Operating and Maintenance (O&M) costs include:
- Feedstock
- Fuel
- Chemicals
- Catalysts
- Solvents
- Raw water make-up
- Direct operating labour
- Maintenance
- Overhead Charges.

The annual O&M costs are generally classified as variable and fixed costs.

Variable cost depends on the annual operating hour of the plant; and the fixed operating costs are essentially independent from the plant operating load. They can be expressed as €/y.

4.2.1. *Variable Cost*

Consumables are the principal components of variable O&M cost. These include feedstock, water, catalysts (Feedstock Purification catalyst, Pre-reforming catalyst, Steam Reformer Catalyst and Shift Catalyst), chemicals, solid waste disposal and others.

Reference values for Natural gas and main consumables prices are summarised in the table below.

Item	Cost
Natural Gas €/GJ (LHV)	6
Raw process water, €/m^3	0.2
Electric power, €/MWh	80
CO_2 transport and storage, €/t CO_2 stored (1)	10
CO_2 emission cost, €/t CO_2 emitted	0

(1) Transport and storage cost as specified by IEAGHG, in accordance with the range of costs information in the European Zero Emissions platform's report "The costs of CO_2 capture, transport and storage", published in 2009. Sensitivity to transport and storage costs are assessed to cover lower or negative cost for EOR, due to the revenue for sale of CO_2, or higher cost, in case of off shore storage with long transport distances.

4.2.2. *Fixed Cost*

The fixed cost of the different plants include the following items:

Direct Labour

The yearly cost of the direct labour is calculated assuming, for each individual, an average cost equal to 60,000 €/y. The number of personnel engaged is estimated for each plant type, considering a 5 shift working pattern.

Administrative and Support Labour

All other company services not directly involved in the operation of the plant fall in this category, such as:

- Management
- Administration
- Personnel services
- Technical services
- Clerical staff.

These services vary widely from company to company and are also dependent on the type and complexity of the operation.

Administrative and support labour is assumed to be 30% of the direct labour and the maintenance labour cost (see below).

Annual Maintenance Cost

A precise evaluation of the cost of maintenance would require a breakdown of the costs amongst the numerous components and packages of the plant. Since these costs are all strongly dependent on the type of equipment selected and statistical maintenance data provided by the selected supplier, this type of evaluation of the maintenance cost is premature at study level.

For this reason the annual maintenance cost of the plant is normally estimated as a percentage of the total plant cost of the facilities, as shown in the following:

- Whole Plant 1.5% of TPC

Maintenance labour is assumed to be 40% of the overall maintenance cost.

Annex II:

Annual Cash Flow

- Base Case: SMR Based Hydrogen Plant without CO_2 Capture
- Case 1A: Hydrogen Plant with CO_2 Capture from Shifted Syngas using MDEA
- Case 1B: Hydrogen Plant with H_2 rich fuel firing burners and CO_2 Capture from Shifted Syngas using MDEA
- Case 2A: Hydrogen Plant with CO_2 Capture from PSA Tail Gas using MDEA
- Case 2B: Hydrogen Plant with CO_2 Capture using Cryogenic and Membrane Separation Technology
- Case 3: Hydrogen Plant with CO_2 Capture from SMR’s Flue Gas using MEA

Cash Flow (€ Million) - EBITDA Basis

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Base Case

Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12
Sales				75.02	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82
Selling and Distribution Expenses															
Net Sales Revenue				***75.02***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***
Variable Costs				-52.78	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48
CO2 Emission Tax															
CO2 Transport & Storage															
Gross Margin				***22.24***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***
Fixed Costs				-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55
Net Margin				***14.70***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***
Residual Value - Capital Expenditure															
Capital Expenditure	-46.33	-81.34	-77.36	-17.82											
Working Capital				-0.04	0.01										
Recurring Capital															
EBITDA (€ Million)	***-46.33***	***-81.34***	***-77.36***	***-3.16***	***22.80***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***

Period	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Sales	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	101.82	
Selling and Distribution Expenses														
Net Sales Revenue	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	***101.82***	
Variable Costs	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	-71.48	
CO2 Emission Tax														
CO2 Transport & Storage														
Gross Margin	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	***30.33***	
Fixed Costs	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	-7.55	
Net Margin	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	
Residual Value - Capital Expenditure														
Capital Expenditure														
Working Capital														0.04
Recurring Capital														
EBITDA (€ Million)	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***22.79***	***0.04***

Internal Rate of Return (IRR)	**8.00%**
Discount Rate	**8.00%**
Net Present Value (NPV) - € Million	**€ 0.00**
Levelised Cost of Hydrogen	**€ 0.1144**

Cash Flow (€ Million) - EBITDA Basis

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 1A - CO2 Capture from Shifted Syngas using MDEA

Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Sales				83.55	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	113.40	
Selling and Distribution Expenses																													
Net Sales Revenue				***83.55***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	***113.40***	
Variable Costs				-54.49	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	-73.80	
CO2 Emission Tax																													
CO2 Transport & Storage Cost				-2.86	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	-3.88	
Gross Margin				***26.21***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	***35.71***	
Fixed Costs				-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	-8.76	
Net Margin				***17.44***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	
Residual Value - Capital Expenditure																													
Capital Expenditure	-54.69	-96.02	-91.14	-21.02																									
Working Capital				-1.04	0.01																								1.04
Recurring Capital																													
EBITDA (€ Million)	***-54.69***	***-96.02***	***-91.14***	***-4.61***	***26.97***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***26.95***	***1.04***

Internal Rate of Return (IRR)	**8.00%**
Discount Rate	**8.00%**
Net Present Value (NPV) - € Million	**(€ 0.0000)**
Levelised Cost of Hydrogen	**€ 0.1351**

Cash Flow (€ Million) - EBITDA Basis

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 1B - H2 Rich Fired SMR and CO2 Capture from Shifted Syngas using MDEA

Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Sales				90.56	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	122.91	
Selling and Distribution Expenses																													
Net Sales Revenue				***90.56***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	***122.91***	
Variable Costs				-57.63	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	-78.03	
CO2 Emission Tax																													
CO2 Transport and Storage Cost				-3.62	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	-4.91	
Gross Margin				***29.32***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	***39.97***	
Fixed Costs				-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	-9.48	
Net Margin				***19.84***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	
Residual Value - Capital Expenditure																													
Capital Expenditure	-61.92	-108.71	-102.96	-23.78																									
Working Capital				-1.31	0.02																								1.31
Recurring Capital																													
EBITDA (€ Million)	***-61.92***	***-108.71***	***-102.96***	***-5.25***	***30.51***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***30.49***	***1.31***

Internal Rate of Return (IRR)	**8.00%**
Discount Rate	**8.00%**
Net Present Value (NPV) - € Million	**(€ 0.0000)**
Levelised Cost of Hydrogen	**€ 0.1465**

Cash Flow (€ Million) - EBITDA Basis

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 2A - CO2 Capture from PSA Tail Gas using MDEA

Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Sales				86.78	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	117.77	
Selling and Distribution Expenses																													
Net Sales Revenue				***86.78***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	***117.77***	
Variable Costs				-54.95	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	-74.42	
CO2 Emission Tax																													
CO2 Transport and Storage				-2.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	-3.79	
Gross Margin				***29.04***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	***39.56***	
Fixed Costs				-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	-9.41	
Net Margin				***19.62***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	
Residual Value - Capital Expenditure																													
Capital Expenditure	-61.26	-107.56	-101.82	-23.52																									
Working Capital				-1.04	0.01																								1.04
Recurring Capital																													
EBITDA (€ Million)	***-61.26***	***-107.56***	***-101.82***	***-4.94***	***30.16***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***30.14***	***1.04***

Internal Rate of Return (IRR) **8.00%**

Discount Rate **8.00%**

Net Present Value (NPV) - € Million **(€ 0.0000)**

Levelised Cost of Hydrogen **€ 0.1424**

Cash Flow (€ Million) - EBITDA Basis

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 2B - CO2 Capture from PSA Tail Gas using Cryogenic and Membrane

Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Sales				86.06	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	116.79	
Selling and Distribution Expenses																													
Net Sales Revenue				***86.06***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	***116.79***	
Variable Costs				-52.66	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	-71.32	
CO2 Emission Tax																													
CO2 Transport & Storage				-2.63	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	-3.57	
Gross Margin				***30.76***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	***41.90***	
Fixed Costs				-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	-9.82	
Net Margin				***20.94***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	
Residual Value - Capital Expenditure																													
Capital Expenditure	-65.43	-114.88	-108.43	-25.09																									
Working Capital				-0.04	0.01																								0.04
Recurring Capital																													
EBITDA (€ Million)	***-65.43***	***-114.88***	***-108.43***	***-4.19***	***32.09***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***32.07***	***0.04***

Internal Rate of Return (IRR)	**8.00%**
Discount Rate	**8.00%**
Net Present Value (NPV) - € Million	**(€ 0.0000)**
Levelised Cost of Hydrogen	**€ 0.1401**

Cash Flow (€ Million) - EBITDA Basis

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 3 - CO2 Capture from SMR's Flue Gas using MEA

Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Sales				101.17	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	137.30	
Selling and Distribution Expenses																													
Net Sales Revenue				***101.17***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	***137.30***	
Variable Costs				-57.92	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	-78.45	
CO2 Emission Tax																													
CO2 Transport & Storage Cost				-4.91	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	-6.66	
Gross Margin				***38.34***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	***52.18***	
Fixed Costs				-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	-11.54	
Net Margin				***26.80***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	
Residual Value - Capital Expenditure																													
Capital Expenditure	-82.74	-145.28	-136.73	-31.70																									
Working Capital				-2.04	0.01																								2.04
Recurring Capital																													
EBITDA (€ Million)	***-82.74***	***-145.28***	***-136.73***	***-6.93***	***40.66***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***40.65***	***2.04***

Internal Rate of Return (IRR)	**8.00%**
Discount Rate	**8.00%**
Net Present Value (NPV) - € Million	**€ 0.0000**
Levelised Cost of Hydrogen	**€ 0.1646**

Annex III:

Breakdown of Total Capital Requirements

Total Capital Requirements

	Base Case Euro (€)	Case 1A Euro (€)	Case 1B Euro (€)	Case 2A Euro (€)	Case 2B Euro (€)	Case 3 Euro (€)
Total Plant Cost (TPC)						
Total Plant Cost	142,460,000	168,170,000	190,400,000	188,390,000	201,200,000	254,440,000
Contingencies	28,492,000	33,634,000	38,080,000	37,678,000	40,240,000	50,888,000
Sub-Total	170,952,000	201,804,000	228,480,000	226,068,000	241,440,000	305,328,000
Spare Parts	854,760	1,009,020	1,142,400	1,130,340	1,207,200	1,526,640
Start-Up & Commissioning Cost						
Start Up CAPEX	3,419,040	4,036,080	4,569,600	4,521,360	4,828,800	6,106,560
Additional Fuel Cost	1,478,446	1,526,705	1,612,371	1,539,572	1,475,093	1,624,222
O&M	1,074,356	1,232,018	1,284,036	1,279,333	1,309,308	1,433,890
Catalyst & Chemicals	163,214	265,197	293,993	289,735	216,080	345,328
Owner's Cost	11,966,640	14,126,280	15,993,600	15,824,760	16,900,800	21,372,960
Interest during Construction	32,941,928	38,871,174	43,989,192	43,520,631	46,452,142	58,709,969
Working Capital	36,337	1,036,337	1,313,691	1,036,337	36,337	2,036,337
Sub-Total	51,934,722	62,102,811	70,198,883	69,142,069	72,425,761	93,155,906
Total Capital Requirements (TCR)	**222,886,722**	**263,906,811**	**298,678,883**	**295,210,069**	**313,865,761**	**398,483,906**

Annex IV:

Annual Operating Expenditure

- Base Case: SMR Based Hydrogen Plant without CO_2 Capture
- Case 1A: Hydrogen Plant with CO_2 Capture from Shifted Syngas using MDEA
- Case 1B: Hydrogen Plant with H_2 rich fuel firing burners and CO_2 Capture from Shifted Syngas using MDEA
- Case 2A: Hydrogen Plant with CO_2 Capture from PSA Tail Gas using MDEA
- Case 2B: Hydrogen Plant with CO_2 Capture using Cryogenic and Membrane Separation Technology
- Case 3: Hydrogen Plant with CO_2 Capture from SMR's Flue Gas using MEA

Annual Operating Expenditure

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Base Case

	Base Number €'000/y	Period -3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12
1. Fixed Cost ('000)																
1a. Direct Labour	€ 2,280.00				2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00
1b. Admin. & General Overhead	€ 991.71				991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71
1c. Insurance & Local Taxes	€ 1,709.52				1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52
1d. Maintenance	€ 2,564.28				2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28
	Total (Fixed O&M Cost)	€ -	€ -	€ -	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51
2. Variable Cost ('000)																
2a. Feedstock Cost	€ 60,906.75				44,878.66	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75
2b. Fuel Cost	€ 10,058.63				7,411.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63
2c. Make Up Water	€ 99.36				73.22	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36
2d. Chemicals	€ 100.00				100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	€ 320.00				320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
	Total (Variable O&M Cost)	€ -	€ -	€ -	€ 52,783.50	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75
3. Revenues ('000)																
3a. Electrcity Export (Import) to the Grid	€ 6,603.01				4,865.37	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01
	Total (Additional Revenues)	€ -	€ -	€ -	€ 4,865.37	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01
4. Cost of Emissions ('000)																
4a. CO2 Emissions Tax	€ -															
	Total (Cost of CO2 Emissions)	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
5. Cost of CO2 Transport & Storage ('000)																
5a. CO2 Transport & Storage	€ -															
	Total (Cost of CO2 Storage)	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -

	13	14	15	16	17	18	19	20	21	22	23	24	25
1. Fixed Cost ('000)													
1a. Direct Labour	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00	2,280.00
1b. Admin. & General Overhead	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71	991.71
1c. Insurance & Local Taxes	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52	1,709.52
1d. Maintenance	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28	2,564.28
Total (Fixed O&M Cost)	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51	€ 7,545.51
2. Variable Cost ('000)													
2a. Feedstock Cost	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75	60,906.75
2b. Fuel Cost	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63	10,058.63
2c. Make Up Water	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36
2d. Chemicals	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
Total (Variable O&M Cost)	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75	€ 71,484.75
3. Revenues ('000)													
3a. Electrcity Export (Import) to the Grid	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01	6,603.01
Total (Additional Revenues)	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01	€ 6,603.01
4. Cost of Emissions ('000)													
4a. CO2 Emissions Tax													
Total (Cost of CO2 Emissions)	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
5. Cost of CO2 Transport & Storage ('000)													
5a. CO2 Transport & Storage													
Total (Cost of CO2 Storage)	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -

Annual Operating Expenditure

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 1A - CO2 Capture from Shifted Syngas using MDEA

	Base Number €'000/y	Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
1. Fixed Cost ('000)																														
1a. Direct Labour	€ 2,580.00					2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00
1b. Admin. & General Overhead	€ 1,137.25					1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25	1,137.25
1c. Insurance & Local Taxes	€ 2,018.04					2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04	2,018.04
1d. Maintenance	€ 3,027.06					3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06	3,027.06
	Total (Fixed O&M Cost)		**€ -**	**€ -**	**€ -**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**	**€ 8,762.35**
2. Variable Cost ('000)																														
2a. Feedstock Cost	€ 60,976.11					44,929.76	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11	60,976.11
2b. Fuel Cost	€ 12,305.74					9,067.39	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74	12,305.74
2c. Make Up Water	€ 101.86					75.06	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86	101.86
2d. Chemicals	€ 100.00					100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	€ 320.00					320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
	Total (Variable O&M Cost)		**€ -**	**€ -**	**€ -**	**€ 54,492.21**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**	**€ 73,803.71**
3. Revenues ('000)																														
3a. Electrcity Export (Import) to the Grid	€ 993.31					731.92	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31	993.31
	Total (Additional Revenues)		**€ -**	**€ -**	**€ -**	**€ 731.92**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**	**€ 993.31**
4. Cost of Emissions ('000)																														
4a. CO2 Emissions Tax	€ -																													
	Total (Cost of CO2 Emissions)		**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**
5. Cost of CO2 Transport & Storage('000)																														
5a. CO2 Transport & Storage	€ 3,877.74					2,857.28	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74	3,877.74
	Total (Cost of CO2 Storage)		**€ -**	**€ -**	**€ -**	**€ 2,857.28**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**	**€ 3,877.74**

Annual Operating Expenditure

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 1B - H2 Rich Fired SMR and CO2 Capture from Shifted Syngas using MDEA

	Base Number €'000/y	Period -3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
1. Fixed Cost ('000)																													
1a. Direct Labour	€ 2,580.00				2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00
1b. Admin. & General Overhead	€ 1,185.26				1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26	1,185.26
1c. Insurance & Local Taxes	€ 2,284.80				2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80	2,284.80
1d. Maintenance	€ 3,427.20				3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20	3,427.20
	Total (Fixed O&M Cost)	**€ -**	**€ -**	**€ -**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**	**€ 9,477.26**
2. Variable Cost ('000)																													
2a. Feedstock Cost	€ 77,393.83				57,027.03	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83	77,393.83
2b. Fuel Cost	€ -																												
2c. Make Up Water	€ 128.66				94.80	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66	128.66
2d. Chemicals	€ 100.00				100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	€ 405.00				405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00
	Total (Variable O&M Cost)	**€ -**	**€ -**	**€ -**	**€ 57,626.83**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**	**€ 78,027.48**
3. Revenues ('000)																													
3a. Electrcity Export (Import) to the Grid	€ 1,026.60				756.44	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60	1,026.60
	Total (Additional Revenues)	**€ -**	**€ -**	**€ -**	**€ 756.44**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**	**€ 1,026.60**
4. Cost of Emissions ('000)																													
4a. CO2 Emissions Tax	€ -																												
	Total (Cost of CO2 Emissions)	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**
5. Cost of CO2 Transport & Storage ('000)																													
5a. CO2 Transport & Storage	€ 4,908.97				3,617.14	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97	4,908.97
	Total (Cost of CO2 Storage)	**€ -**	**€ -**	**€ -**	**€ 3,617.14**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**	**€ 4,908.97**

Annual Operating Expenditure

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 2A - CO2 Capture from PSA Tail Gas using MDEA

Period	Base Number €'000/y	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12
1. Fixed Cost ('000)																
1a. Direct Labour	€ 2,580.00				2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00
1b. Admin. & General Overhead	€ 1,180.92				1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92
1c. Insurance & Local Taxes	€ 2,260.68				2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68
1d. Maintenance	€ 3,391.02				3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02
	Total (Fixed O&M Cost)	€ -	€ -	€ -	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62
2. Variable Cost ('000)																
2a. Feedstock Cost	€ 60,904.13				44,876.73	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13
2b. Fuel Cost	€ 12,995.33				9,575.50	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33
2c. Make Up Water	€ 101.36				74.69	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36
2d. Chemicals	€ 100.00				100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	€ 320.00				320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
	Total (Variable O&M Cost)	€ -	€ -	€ -	€ 54,946.92	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82
3. Revenues ('000)																
3a. Electrcity Export (Import) to the Grid	-€ 712.36				-524.90	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36
	Total (Additional Revenues)	€ -	€ -	€ -	-€ 524.90	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36
4. Cost of Emissions ('000)																
4a. CO2 Emissions Tax	€ -															
	Total (Cost of CO2 Emissions)	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
5. Cost of CO2 Transport & Storage('000)																
5a. CO2 Transport & Storage	€ 3,791.72				2,793.90	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72
	Total (Cost of CO2 Storage)	€ -	€ -	€ -	€ 2,793.90	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72

Period	13	14	15	16	17	18	19	20	21	22	23	24	25
1. Fixed Cost ('000)													
1a. Direct Labour	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00
1b. Admin. & General Overhead	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92	1,180.92
1c. Insurance & Local Taxes	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68	2,260.68
1d. Maintenance	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02	3,391.02
Total (Fixed O&M Cost)	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62	€ 9,412.62
2. Variable Cost ('000)													
2a. Feedstock Cost	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13
2b. Fuel Cost	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33	12,995.33
2c. Make Up Water	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36	101.36
2d. Chemicals	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
Total (Variable O&M Cost)	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82	€ 74,420.82
3. Revenues ('000)													
3a. Electrcity Export (Import) to the Grid	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36	-712.36
Total (Additional Revenues)	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36	-€ 712.36
4. Cost of Emissions ('000)													
4a. CO2 Emissions Tax													
Total (Cost of CO2 Emissions)	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -	€ -
5. Cost of CO2 Transport & Storage('000)													
5a. CO2 Transport & Storage	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72	3,791.72
Total (Cost of CO2 Storage)	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72	€ 3,791.72

Annual Operating Expenditure

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 2B - CO2 Capture from PSA Tail Gas using Cryogenic and Membrane

	Base Number €'000/y	Period -3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12
1. Fixed Cost ('000)																
1a. Direct Labour	€ 2,580.00				2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00
1b. Admin. & General Overhead	€ 1,208.59				1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59
1c. Insurance & Local Taxes	€ 2,414.40				2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40
1d. Maintenance	€ 3,621.60				3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60
	Total (Fixed O&M Cost)	**€ -**	**€ -**	**€ -**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**
2. Variable Cost ('000)																
2a. Feedstock Cost	€ 60,904.13				44,876.73	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13
2b. Fuel Cost	€ 9,900.32				7,294.97	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32
2c. Make Up Water	€ 99.36				73.22	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36
2d. Chemicals	€ 100.00				100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	€ 320.00				320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
	Total (Variable O&M Cost)	**€ -**	**€ -**	**€ -**	**€ 52,664.92**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**
3. Revenues ('000)																
3a. Electrcity Export (Import) to the Grid	€ 189.08				139.32	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08
	Total (Additional Revenues)	**€ -**	**€ -**	**€ -**	**€ 139.32**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**
4. Cost of Emissions ('000)																
4a. CO2 Emissions Tax	€ -															
	Total (Cost of CO2 Emissions)	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**
5. Cost of CO2 Transport & Storage ('000)																
5a. CO2 Transport & Storage	€ 3,569.04				2,629.82	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04
	Total (Cost of CO2 Storage)	**€ -**	**€ -**	**€ -**	**€ 2,629.82**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**

	13	14	15	16	17	18	19	20	21	22	23	24	25
1. Fixed Cost ('000)													
1a. Direct Labour	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00
1b. Admin. & General Overhead	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59	1,208.59
1c. Insurance & Local Taxes	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40	2,414.40
1d. Maintenance	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60	3,621.60
Total (Fixed O&M Cost)	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**	**€ 9,824.59**
2. Variable Cost ('000)													
2a. Feedstock Cost	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13
2b. Fuel Cost	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32	9,900.32
2c. Make Up Water	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36	99.36
2d. Chemicals	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
Total (Variable O&M Cost)	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**	**€ 71,323.81**
3. Revenues ('000)													
3a. Electrcity Export (Import) to the Grid	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08	189.08
Total (Additional Revenues)	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**	**€ 189.08**
4. Cost of Emissions ('000)													
4a. CO2 Emissions Tax													
Total (Cost of CO2 Emissions)	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**
5. Cost of CO2 Transport & Storage ('000)													
5a. CO2 Transport & Storage	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04	3,569.04
Total (Cost of CO2 Storage)	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**	**€ 3,569.04**

Annual Operating Expenditure

Techno-Econoic Evaluation of Deploying CCS in an SMR Based H2 Production using NG as Feedstock & Fuel
Case 3 - CO2 Capture from SMR's Flue Gas using MEA

	Base Number €'000/y	Period	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
1. Fixed Cost ('000)																														
1a. Direct Labour	€ 2,580.00					2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00	2,580.00
1b. Admin. & General Overhead	€ 1,323.59					1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59	1,323.59
1c. Insurance & Local Taxes	€ 3,053.28					3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28	3,053.28
1d. Maintenance	€ 4,579.92					4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92	4,579.92
		Total (Fixed O&M Cost)	**€ -**	**€ -**	**€ -**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**	**€ 11,536.79**
2. Variable Cost ('000)																														
2a. Feedstock Cost	€ 60,904.13					44,876.73	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13	60,904.13
2b. Fuel Cost	€ 17,058.54					12,569.45	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54	17,058.54
2c. Make Up Water	€ 70.07					51.63	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07	70.07
2d. Chemicals	€ 100.00					100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
2e. Catalyst	€ 320.00					320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
		Total (Variable O&M Cost)	**€ -**	**€ -**	**€ -**	**€ 57,917.81**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**	**€ 78,452.75**
3. Revenues ('000)																														
3a. Electrcity Export (Import) to the Grid	€ 283.61					208.98	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61	283.61
		Total (Additional Revenues)	**€ -**	**€ -**	**€ -**	**€ 208.98**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**	**€ 283.61**
4. Cost of Emissions ('000)																														
4a. CO2 Emissions Tax	€ -																													
		Total (Cost of CO2 Emissions)	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**	**€ -**
5. Cost of CO2 Transport & Storage ('000)																														
5a. CO2 Transport & Storage	€ 6,661.08					4,908.16	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08	6,661.08
		Total (Cost of CO2 Storage)	**€ -**	**€ -**	**€ -**	**€ 4,908.16**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**	**€ 6,661.08**

Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

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