- Firewater
- Water treatment chemicals
- Chemicals for the gasification unit

The following commodities are produced from the plant at the battery limits:

- Dry carbon dioxide product
- Hydrogen rich stream to existing fuel gas system
- Electrical power
- Sulfur product
- Treated wastewater suitable for disposal
- Filter waste
- Sulfur recovery vent
- Air Separation Unit vent
- Flue gas
- Cooling tower evaporation
- Cooling tower drift (water droplets carried by the wind)
- Sewage
- Storm Drains

The firewater is the only integration of the new plant with the existing utility systems.

4.2 Site Data

4.2.1 Location

The case is based on a typical European refinery and is modeled after BP's facilities at Grangemouth. Site information was taken from Exhibit E – Technical Specification: BP Grangemouth (Scenario A), Revision C dated October 1, 2001 (PC-RFP-006).

BP Grangemouth collects oil and gas from fields across the Central Area of the North Sea. The complex is made up of a series of business units, including:

a) Kinneil – gas and liquids collected from the Forties system are stabilized, separated and processed.

b) Refinery – crude oil collected from the Forties Pipeline system is refined to produce LPG, Alkylate, Petrol, Diesel Jet Fuel, Kerosene and Fuel Oil.

c) Chemicals – gases and light distillate feedstocks from the refinery are converted to petrochemical products.

d) Power Station – power and steam are produced for users in the complex.

BP Grangemouth is located between the estuaries of the Rivers Carron and Avon in Scotland, United Kingdom. The exact plot location of the gasification plant in the existing plant is to be determined; however, it is assumed that the plot is clean, level and free of any underground obstructions.

The elevation of the plot is 3.5 meters above sea level. The associated barometric pressures are shown in Table 4-1.

Table 4-1
Barometric Pressures (mbara)

Estimated mean	1015
Maximum	1030
Minimum	970

4.2.2 Meteorological Data

4.2.2.1 Site Temperatures

The dry bulb temperatures are summarized in Table 4-2.

Table 4-2
Ambient Air Dry Bulb Temperatures (°C)

Estimated mean	7°C
Maximum	30°C
Minimum	-12°C
Design temperature for winter	-15°C

4.2.2.2 Relative Humidity

The relative humidity for the site is shown in Table 4-3. The average relative humidity of 78.5% is estimated using the mathematical average of the two humidities reported in the morning (0700) and the afternoon (1500).

Table 4-3 Relative Humidity (%)	
Average	78.5
At 0700	87
At 1500	70

4.2.2.3 Rainfall

The annual average rainfall is 815 mm with a one (1) hour maximum of 6.5 mm.

4.2.2.4 Wind

The maximum wind velocity is 50 m/s.

4.3 Process Design Basis

4.3.1 Feedstocks

There are a wide range of existing process furnaces and heaters, distributed across the BP Grangemouth complex. These units are fired with fuel gas from the refinery or chemicals plants and refinery fuel oil. In the CO_2 Capture Report, Grangemouth developed by Fluor, the flue gases from these furnaces and heaters were routed to a proposed plant for the post combustion recovery of carbon dioxide. There were approximately twenty (20) points of source emissions for the carbon dioxide, which added up to twice the amount required for recovery for the Grangemouth site. Therefore, sources were eliminated based on the following:

a) Size of source.

b) Distance from the proposed carbon dioxide recovery plant.

c) Potential difficulties in making ties ins between the carbon dioxide plant and existing flue gas ducting.

d) Operational status in the future.

The remaining sources fell into three natural groupings:

a) BP refinery group
b) Power plant group
c) BP Chemicals ethylene plant source group

The final selection consisted of refinery sources F, G, H & I, power plant sources K, L & M and finally the ethylene plant sources S & T. For this

MWGS Reactor Study, the feed usually fed to these existing furnaces and heaters will be routed to the proposed gasification plant. The hydrogen rich fuel gas from the membrane WGS reactor will be fed to the existing furnaces and heaters. Any deficiency of fuel for the existing equipment will be augmented by natural gas. The amount of fuel available to the gasification plant is set by the BP Grangemouth Technical Specification (Exhibit E). The feed will be adjusted so that two (2) million tonnes of carbon dioxide per year is recovered from the plant (based on 330 days per year operation and a carbon recovery of 100%). The feed is supplied to the gasifier in the following priority:

a) Fuel oil,
b) Refinery fuel gas,
c) Fuel gas from the chemicals plant, and
d) Natural gas.

The summary of the annual fuel consumption of the existing equipment is shown in Table 4-4.

Table 4-4 Annual Fuel Consumption for Existing Equipment					
		Tonnes/yr		kg/hr (based on 330 days per year operation)	
	Source	**Gas**	**Oil**	**Gas**	**Oil**
Refinery Site Stacks					
F	CCR	63,972	2,324	8,077	293
G	HCU	52,117	-	6,580	-
H	VDU	26,676	7,797	3,368	984
I	H2U	35,039	-	4,424	-
Total		177,804	10,121	22,449	1,277
Power Plant Stacks					
K	Boiler 9/10	45,614	79,612	5,759	10,052
L	Boiler 11/12/13	81,502	114,218	10,291	14,421
M	Boiler 14/15	104,559	107,970	13,202	13,633
Total		231,675	301,800	29,252	38,106
BP Chemicals Stacks					
S	KG (36F1A/F)	136,200	-	17,197	-
T	Boilers	49,100	-	6,199	-
Total		185,300	-	23,396	-
Overall Total Fuel Oil			**311,921**		**39,384**
Overall Total Refinery Fuel Gas		**409,479**		**51,702**	
Overall Total Fuel Gas from Chemicals Plant		**185,300**		**23,396**	

The quality of the Fuel Oil varies significantly. Therefore, the ultimate analysis for the Fuel Oil to the gasifier was estimated as an average and is shown in Table 4-5 (reference: CCP Membrane Water Gas Shift Reactor Invitation for Proposals).

Table 4-5 Fuel Oil Ultimate Analysis	
	wt%
Carbon	87.2
Hydrogen	9.9
Nitrogen	0.7
Oxygen	0.8
Sulfur	1.4
Total	100.0
Flow rate available, kg/hr (Note 2)	39,384

Notes:
1) Ash content is assumed to be zero.
2) Based on 330 days per year operation

The quality of the fuel gas varies significantly across the Grangemouth site. Therefore, an analysis of the refinery and chemicals plant fuel gas was estimated as an average and is shown in Table 4-6 (reference: BP Grangemouth Technical Specification).

Table 4-6
Fuel Gas Typical Analysis

	Refinery Fuel Gas	Chemicals (Site 1)
	mol%	mol%
Methane	67.80	58.0
Ethane	9.42	0.1
Ethene	0.02	0.1
Propane	7.42	0.0
Propene	0.01	0.0
Iso-Butane	1.07	0.0
N-Butane	3.12	0.0
Iso-Butene	0.05	0.0
Methyl-1-Butenes	0.15	0.0
n-Pentane	0.04	0.0
Iso-Pentane	0.16	0.0
Hydrogen	7.87	40.8
Oxygen	0.03	0.0
Nitrogen	0.75	1.0
Carbon Monoxide	0.00	0.0
Carbon Dioxide	2.01	0.0
Hydrogen Sulfide	0.08	0.0
Total	100.00	100.0
Flow rate available, kg/hr*	51,702	23,396

*Note: Based on 330 days per year operation.

4.3.2 Products

The products of the plant are a hydrogen rich stream to the existing furnaces and heaters and a carbon dioxide rich stream for sequestration. In the CCP Membrane Water Gas Shift Reactor Invitation for Proposals, the target production rate of the hydrogen is 700,000 Nm^3/hr. However, CCP has directed Fluor that recovering the amount of hydrogen corresponding to two million tonnes per year of carbon dioxide captured is sufficient for this project. Therefore, the design of the plant was not constrained by a hydrogen production rate of 700,000 Nm^3/hr. The specifications for the product streams are shown in Table 4-7.

Table 4-7
Product Specifications

	CO_2	H_2
Production Rate, million tonnes/yr (100% basis with carbon recovery of 100% (Note1))	2	Governed by amount of fuel to gasifier and extent of shift conversion
kg/hr (Note 2)	252,525	To be determined
Nm^3/hr (Note 2)	128,609	To be determined
Target design carbon recovery, % (Note 1)	90	-
Minimum purity, mol%, dry	90	-
Minimum heating value, Btu/SCF (LHV)	-	150
Temperature at battery limits, °C	45	45
Minimum pressure at battery limits, bara	80	3

Notes:
1) Carbon recovery = carbon compounds in retentate/carbon compounds in feed
2) Based on 330 days per year operation.

4.3.3 Make-up Water

Make-up water is available as Towns Water from the local water supplier (reference: BP Grangemouth Technical Specification). It is possible that chemically treated cooling water and demineralized water may be provided by the existing facilities. However, at this phase of the project, it is assumed the new plant requires facilities for water treating. In the event, demineralized water is imported from the existing facilities, the feedwater is accessible at 150 barg ±4 bar and 126°C. The parameters for the feedwater quality from the existing plant are shown in Table 4-8 and are based on a steam drum pressure of 140 barg.

Table 4-8 Demineralized Water Quality (Potentially Available from Existing Facilities)		
Normal Conductivity	2.5 – 6	µS/cm
pH	8.5 – 9.5	
Silica as SiO_2	< 0.02	mg/kg
Iron	< 0.02	mg/kg
Aluminum	-	mg/kg
Sulfate as SO_4	-	mg/kg
Sodium	-	mg/kg
Copper	< 0.003	mg/kg
Hardness as $CaCO_3$	< 0.15	mg/kg
Oxygen	< 0.01	mg/kg

For the majority of the time, the make-up water is supplied by the Towns Water. A typical water quality is shown in Table 4-9.

Table 4-9 Towns Water Typical Quality		
Conductivity	68 – 128	µS/cm
pH	7.2 – 10.0	
Turbidity	0.12 – 1.17	FTU
Iron as Fe	< 2 – 272	µg/l
Aluminum as Al	17 – 170	µg/l
Sulfate as SO_4	4.7 – 19.3	mg/l
Sodium as Na	3.6 – 5.8	mg/l
Copper as Cu	1.8 – 52.6	µg/l
Dry Residues	57 – 61	mg/l
Calcium as Ca	5.7 – 9	mg/l
Magnesium as Mg	0.97 – 1.6	mg/l
Chlorides as Cl	6.4 – 10.4	mg/l
Ammonium as NH_4	0.004 – 0.0019	mg/l
Total Organic Carbon as C	1.03 – 1.22	mg/l
Alkalinity as HCO_3	9.8 – 18.3	mg/l
Manganese as Mn	< 0.5 – 24.2	µg/l

Table 4-9 Towns Water Typical Quality		
Phosphorus as P	< 8 – 162	µg/l
Barium as Ba	15 – 18	µg/l
Lead as Pb	< 0.4 – 37.8	µg/l
Nickel as Ni	1.5 – 6.2	µg/l
Mercury as Hg	< 0.05 – 0.36	µg/l
Chromium as Cr	< 0.8 – < 1.0	µg/l
Zinc as Zn	5 – 315	µg/l
Cadmium as Cd	< 0.4 – < 0.5	µg/l

4.3.4 Environmental Criteria

The level of pollutants in the plant emissions should be below those of the current operating environmental discharges. Environmental limits for the new plant are to be determined. The existing emissions for NOx and SO_2 are provided in Table 4-10.

Table 4-10
Existing Emissions

Stack	Fuel Fired	Total Flue Gas Flow Rate, kg/hr	NOx, ppm (Note 1)	SO_2, ppm
F	Oil/Gas	188,616	300	37
G	Gas	155,762	100	27
I	Gas	105,639	100	27
K	Oil/Gas	322,778	300	211
L	Oil/Gas	514,604	300	192
M	Oil/Gas	558,474	300	171
S	Gas	402,257	100	0
T	Gas	146,437	100	0

Notes:
1) NOx emissions are estimated.
2) No emissions were provided for Stack H.

The plant emission/effluent points are as follows:

- Flue gas,
- Sulfur recovery vent

- Air Separation Unit vent
- Cooling tower evaporation/drift
- Waste water
- Sewage
- Storm Drains
- Sulfur product,
- Cooling tower evaporation/drift,
- Waste water, and
- Filter waste.

Noise limitations at the site boundary are < 55 dB.

4.3.5 Utility Information

The following utilities are provided for the plant:

- Steam
- Boiler Feedwater
- Condensate
- Cooling Water
- Demineralized Water
- Plant Water
- Potable Water
- Firewater
- Drains and Blowdown
- Plant and Instrument Air
- Nitrogen
- Natural Gas
- Flare
- Electrical Power

Conditions for the steam are shown in Table 4-11.

Table 4-11 Selected Utility Conditions			
Commodity	**Pressure, barg**	**Saturation Temperature °C**	**Superheat Temperature °C**
Extra High Pressure Steam	127	330	520
High, High Pressure Steam	43	256	400
High Pressure Steam	33	241	400
Medium Pressure Steam	12.8	194	245
Low Pressure Steam (typically)	1	120	240

The cooling water system is a stand-alone unit. The cooling water supply temperature is set to 23°C, which results in a 5°C approach temperature to the assumed design wet bulb temperature of 18°C. The maximum temperature rise is 26°C.

The cooling tower blowdown is calculated such that the cooling towers operate at five (5) cycles of concentration. The design of the cooling towers (e.g. supply temperature, design wet bulb temperature, maximum temperature rise and cycles of concentration) were set to be the same as the design in the BP Grangemouth CO_2 Capture Report.

It is assumed that firewater is provided from the existing site infrastructure. (This is the same as the design in the BP Grangemouth CO_2 Capture Report.)

Plant and instrument air and utility nitrogen are supplied by the Air Separation Unit.

Natural gas is supplied to the new gas turbine for the production of electrical power.

4.3.6 Units of Measurement

The design incorporates SI units. The specific units to be used on this project for each type of measurement are shown in Table 4-12.

Table 4-12
Units of Measurement

Measurement	Unit
Temperature	°C
Pressure	barg, bara
Vacuum	mbar
Mass	kg
Volume, liquids	m^3
Volume, gases (actual)	m^3
Volume, gases (standard)	Nm^3
Density	kg/m^3
Flow, liquids	m^3/h
Flow, gases	Nm^3/h, m^3/h, kg/h
Flow, solids	kg/h, kg/s
Heat	kJ/h
Power	MW, kW
Velocity	m/s

The following prefixes in Table 4-13 may be used.

Table 4-13
Unit Prefixes

Multiplication Factor	Prefix	Symbol
10^9	Giga	G
10^6	Mega	M
10^3	Kilo	k
10^{-2}	Centi	c
10^{-3}	Milli	m

5.0 PROCESS DESCRIPTIONS

The following section describes the main process systems for the gasification plant with a Membrane Water Gas Shift (MWGS) Reactor. The flow rates, temperatures and pressures referenced in the text correspond to the normal operating conditions. (See Section 6.0 for corresponding process schematics.) The performance of the gasification plant with the sulfur tolerant metal ceramic composite membrane with permeances based on experimental data for a sweet syngas feed is shown in Table 5-1.

Table 5-1
Gasification Plant Performance
Metal Ceramic Composite Membrane

Gasifier feed (41% fuel oil/59% refinery fuel gas)	3802.8 GJ/hr (LHV)
Natural gas for power generation	755.8 GJ/hr (LHV)
Total fuel to plant	4558.6 GJ/hr (LHV)
Hydrogen fuel return to existing boilers	2800.1 GJ/hr (LHV)
Overall thermal efficiency for hydrogen fuel	61%
Carbon dioxide to sequestration (100% CO_2)	2.02 million tonnes/yr
Power Generation	MWe
Combustion Turbine	72
Steam Turbine	34
Auxiliary Power Consumption	69
Net Power Export	37

The overall block flow diagram (BFD-001) for the plant shows the main process flow scheme. Information for major streams is shown in Table 5-2 for the corresponding heat and material balance. The plant is a self-supporting facility with the necessary utilities and support systems. The plant is composed of the following process units and utilities:

- Air Separation Unit
- Gasification Island
- Preheating and Bulk Shift Catalyst Unit
- Membrane WGS Reactor
- Permeate Cooling Unit
- Retentate Cooling Unit
- Condensate (Ammonia) Stripper Unit
- Sulfur Recovery (Sulferox) Unit
- CO2 Compression/Dehydration Unit

- Natural Gas Fired Combined Cycle
- Utilities & supporting systems include:
  - Natural gas supply
  - Demineralized water package
  - Cooling water package
  - Potable water package
  - Oily water separator
  - Fire protection and monitoring systems (firewater supplied by existing plant)
  - Back-up plant and instrument air package
  - Wastewater treatment package (includes drains and sewer)
  - Flare system
  - Miscellaneous material handling system
  - Electrical distribution
  - Uninterruptible power supply (UPS)
  - Generator step-up transformer
  - Continuous emissions monitoring system (CEMS)
  - Distributed control system (DCS)
  - Interconnecting piping
  - Other supporting facilities (Process analyzers; Hazardous gas detection system; Communications; Control room; Maintenance, warehouse and administration facility; Laboratory for inspection, certification and process control; Turbine building; Overhead turbine crane; Heating, ventilation and air conditioning (HVAC) systems; and Roads, parking, fencing and lighting)