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Abstract

This report is the first result of the activities of the European Benchmarking Task Force (EBTF) – a team of participants of three CCS R&D projects, which are DECARBit, CAESAR and CESAR. It defines a set of parameters to be applied to the study of CCS technologies in these three projects and in future European CCS R&D projects. Such parameters are related to ambient conditions, fuels, gas separation, coal gasification, shift reaction, gas turbine, steam cycle, heat exchangers, efficiency calculations, emission limits and economic assessment criteria. Its purpose is to serve as a basis for cycle definition, cycle analysis, comparison of different technologies and comparison of economic evaluations, making such comparisons consistent and reliable, by being based on the same set of fundamental assumptions. It builds on previous work carried out in FP6 projects, in particular ENCAP, DYNAMIS, CASTOR and CACHET. Power generation technology development has been fast in recent years and so values that are considered appropriate now may require some revision in the near future. Also, because the EBTF is formed by a number of experts from different areas of Europe, consensus is not always easily or quickly achieved. For these reasons, this report should be considered a living document, subject to revisions by its authors, coming not only from their experience in the projects themselves but also from suggestions that the report may attract from other experts, readers and users.

Public introduction (*)
This report is the first result of the activities of the European Benchmarking Task Force (EBTF) – a team of participants of three CCS R&D projects, which are DECARBit, CAESAR and CESAR. It defines a set of parameters to be applied to the study of CCS technologies in these three projects and in future European CCS R&D projects. Such parameters are related to ambient conditions, fuels, gas separation, coal gasification, shift reaction, gas turbine, steam cycle, heat exchangers, efficiency calculations, emission limits and economic assessment criteria. Its purpose is to serve as a basis for cycle definition, cycle analysis, comparison of different technologies and comparison of economic evaluations, making such comparisons consistent and reliable, by being based on the same set of fundamental assumptions. It builds on previous work carried out in FP6 projects, in particular ENCAP, DYNAMIS, CASTOR and CACHET. Power generation technology development has been fast in recent years and so values that are considered appropriate now may require some revision in the near future. Also, because the EBTF is formed by a number of experts from different areas of Europe, consensus is not always easily or quickly achieved. For these reasons, this report should be considered a living document, subject to revisions by its authors, coming not only from their experience in the projects themselves but also from suggestions that the report may attract from other experts, readers and users.

(*) According to Deliverables list in Annex I, all restricted (RE) deliverables will contain an introduction that will be made public through the project WEBsite

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1. INTRODUCTION

This report presents a collection of parameters that should serve as a basis for cycle definition, cycle analysis, comparison of different technologies and comparison of economic evaluations. Its objective is to make such comparisons consistent and reliable, by being based on the same set of fundamental assumptions. Its objective is not to recommend any values as the right or best ones to be used in any future power plant project. Also, it is important, particularly in economic evaluations, that the origin of data and assumptions is clear and well documented and this is another objective of this work.

The report is a contribution from three projects sponsored by the European Commission in FP7: DECARBIT, CESAR and CAESAR. A large portion of the material included here comes from previous FP6 projects – ENCAP, DYNAMIS, CASTOR and CACHET. The contributors from DECARBit are NTNU, Shell, University of Ulster and ALSTOM, the contributors from CESAR are TNO and E.ON and the contributor from CAESAR is Politecnico di Milano.

The report begins with the very basic selection of unit system and ambient conditions. It then describes the characteristics of three types of fuel: Bituminous coal, Lignite and Natural Gas. As the objective of the projects of interest is to study the technologies of power generation, the authors think that three standard compositions are sufficient. After these definitions, the report describes the choice of parameters for a number of modules or processes of the power plants objective of study. Such modules and processes are air separation, coal gasification, shift reaction, gas turbine, steam cycle and heat exchangers. Then more general issues are defined: the procedure for efficiency calculation, CO_2 treatment and emission limits from solid fuels. Finally, criteria for economic assessments of new technologies and cycles are established.

2. GENERAL DEFINITIONS AND CONDITIONS

In this chapter very basic definitions are made. These are the unit system to be used in formal comparisons of technologies and economic evaluations and the ambient conditions on which the calculations are to be based.

2.1 Units

In all reports and presentations, SI units - ***S****ystème* ***I****nternational d'Unités* – is to be used.

2.2 Ambient conditions

Ambient conditions vary from site to site. However, it has been decided to use ISO standard conditions for an inland construction site with natural draught cooling towers. Such conditions are:

2.2.1 Air

- Pressure: 0.101325 MPa
- Temperature: 15 ^{o}C
- Relative humidity: 60%
- Composition: Table 2-1 below

Table 2-1 – Air composition

Component	Volume fraction dry	Volume fraction at 60% Relative Humidity
N_2	78.09	77.30
CO_2	0.03	0.03
H_2O		1.01
Ar	0.932	0.923
Oxygen	20.95	20.74
Gas constant [J/(kg K)]	287.06	288.16
Molecular weight	28.964	28.854

2.2.2 Power plant heat rejection

Calculations of energy and mass balances should be based on the following conditions for heat rejection by the power plant to the cooling medium:

- Condensing pressure: 48 mbar (note 1)
- Cooling water temperature: 18.2 ^{o}C (note 2)

Notes:
1) This condensing pressure gives high efficiency but requires large cooling towers and consequently high investments. So, different pressures may be considered in evaluations, if their effect is properly highlighted.

2) When applying the ISO conditions this is equivalent to a temperature of 10.8 ^oC wet bulb that, with cooling tower pinch of 7.4 ^oC, gives a cooling water temperature at the inlet of the condenser of 18.2 ^oC. If the cooling water temperature at the outlet of the condenser is 29.2 ^oC. with a condenser pinch of 3 ^oC, the temperature inside the condenser equals 32.2 ^oC, equivalent to 48 mbar. A different temperature may be used in calculations, if the effect of a different choice is highlighted.

3 FUEL

The characteristics of the fuel are fundamental in energy and mass balance calculations and in the definition of processes such as gasification, gas reforming, gas cleaning and combustion. They also affect efficiency results and economic evaluations. However, the authors assume that three basic types of fuel are representative of all fuels of interest in the power generation technologies studied in CCS projects. They are Bituminous Douglas Premium coal, Lignite and Natural Gas. In order to ensure as much consistency across projects as possible, the characteristics of these three types of fuels adopted here are those adopted in previous FP6 projects – ENCAP, DYNAMIS, CASTOR and CACHET.

3.1 Bituminous Douglas Premium Coal

The composition, calorific values and CO_2 emissions of the Bituminous Douglas Premium coal is given in Table 3.1.

Table 3-1 – Douglas Premium coal characterisitics			
Proximate analysis %		**Ultimate analysis %**	
Moisture	8.000	Carbon	66.520
Ash	14.150	Nitrogen	1.560
Volatiles	22.900	Hydrogen	3.780
Fixed carbon	54.900	Total sulphur	0.520
Total sulphur	0.520	Ash	14.150
		Chlorine	0.009
		Moisture	8.000
		Oxygen	5.460
HHV (MJ/kg)	26.230		
LHV (MJ/kg)	25.170		
CO_2 emission (g/kWh LHV)	3490		

3.2 Lignite

The composition, calorific values and CO_2 emissions of Lignite is given in Table 3.2.

Table 3-2 – Lignite characteristics			
	German blend		**Greek Florina**
	As received %	Pre-dried %	%
Moisture	54.50	12.00	36.80
Ash	4.90	9.50	27.40
Carbon	27.30	52.80	22.60
Hydrogen	2.00	3.90	2.10
Nitrogen	0.40	0.80	0.37
Oxygen	10.30	19.90	9.88
Sulphur	0.60	1.10	0.94
HHV (MJ/kg)	10.778		
LHV (MJ/kg)	9.010	19.700	7.955
CO_2 emission (g/kWh LHV)	400		375

3.3 Natural Gas

The composition, calorific values and CO_2 emissions of natural gas are given in Table 3.3.

Table 3-3 – Natural gas characteristics (ENCAP)	
Component	**Volume %**
CH4 - Methane	89.00
C2H6 - Ethane	7.00
C3H8 - Propane	1.00
C4-i – I-Butane	0.05
C4-n – N-Butane	0.05
C5-i – I-Pentane	0.005
C5-n – N-Pentane	0.004
CO2	2.00
N2	0.89
S	< 5 ppm
HHV (MJ/kg)	51.473
LHV (MJ/kg)	46.502
CO_2 emission g/kWh LHV	208

It is assumed that natural gas is supplied at 10 ^{o}C and 7 MPa.

4 AIR SEPARATION

The specifications provided here are for state-of-the-art cryogenic air separation units. New technologies developed for air separation, either in DECARBit SP3 or any other project do not need to comply with these specifications.

4.1 Integration with the power plant and gas stream conditions

4.1.1 Integration with the power plant

Air supplied to the Air Separation Unit (whatever the separation process) may come from the compressor of the gas turbine, from an entirely independent compressor or part from the gas turbine and part from an independent compressor. So, 100% integration of the air separation process with the power plant means that all air supplied to the process comes from the compressor of the gas turbine. An integration of 0% means that all air comes from an entirely independent compressor. The present experience with power plants based on coal gasification recommends a maximum of 50% integration, on grounds of reliability and availability. So, for purposes of definition of base cycles, this is the value that should be adopted.

4.1.2 Gas stream conditions

The following specifications follow information provided by Shell:

4.1.2.1 Temperature of the Nitrogen leaving the ASU: 22 ^{o}C [Shell, personal communication, June 2008]
4.1.2.2 Oxygen purity: 95% ['Shell Coal Gasification Process', DECARBIT internal report, Rev. 3, May 22, 2008]
4.1.2.3 Nitrogen purity for fuel dilution at the gas turbine: 99% [Shell, personal communication, June 2008]
4.1.2.4 Nitrogen purity for the gasifier: 99.9% [Shell, personal communication, June 2008]

4.2 Energy requirement for oxygen production

For reference purposes only, an equation is given here for the calculation of the energy requirement for generating an oxygen-rich stream at pressures above 0.238 MPa. The equation is (pressure in bars)

Power(kWh/ton O_2) = 697* 0.11 * log10(P/2.38) [*Source: ENCAP*]

Other equations may be used but their origin should be mentioned.

4.3 Energy requirement for nitrogen production

For reference purposes only, an equation is given here for the calculation of the energy requirement for production of pure nitrogen at pressures above 0.1 MPa (pressure in bars):

Power(kWh/ton N_2) = 800* 0.11 * log10(P/1.013) [*Source: ENCAP*]

The delivery temperature for the pure nitrogen stream is determined by the pressure after the main heat exchanger in the ASU and the specified delivery pressure. The nitrogen pressure after the main heat exchanger is determined by the air feed pressure to the ASU:

$$p_{N_2,prod} = p_{air} \cdot \left(0.0728 \cdot \ln\left(p_{air}\right) + 0.126\right) - 0.300$$ [Source: ENCAP]

p_{air} = ASU air feed pressure [bara] 5.5 bara < p_{air} < 21 bara
$p_{N2, prod}$ = pressure of the pure nitrogen stream after the main heat exchanger [bara]

The temperature of the pure nitrogen stream after the main heat exchanger is 15 ^oC. To estimate the delivery temperature, a compression process from the pressure after the main heat exchanger and 15 ^oC to the delivery pressure is calculated using an isentropic efficiency of 80 %. The power consumption for this compression process should be approximately the same as the one calculated with the power requirement equation for nitrogen given above.

Again, other equations may be used for this purpose but their origin should be mentioned.

5 COAL GASIFICATION

5.1 Main process parameters

Shell gasification technology specifications are adopted for the base case cycle [*Decarbit_SCGP Info_1 Revised.pdf*]. Two study cases are in general considered by Shell:

- Base case, with convective cooler, dry solids removal and scrubber
- Alternative case, with water quench and wet scrubbing

Here only the Base case is considered because it is seen as more appropriate to the Douglas Premium Bituminous coal.

The conditions at the outlet of the gasifier are:

- Gasifier outlet pressure: 4.4 MPa
- Gasifier outlet temperature : 1550 °C
- HP steam produced at the gasifier:
  - Flow rate: 2.4737 t / t of coal
  - Pressure: 14.4 MPa
  - Temperature: 339 °C
- MP steam produced at the gasifier:
  - Flow rate: 0.5186 t / t of coal
  - Pressure: 5.4 MPa
  - Temperature: 300 °C

The syngas leaving the gasifier to acid removal or shift reaction has the conditions and compositions given below, downstream the scrubber:

- Temperature: 165 °C
- Pressure: 4.1 MPa
- Flow rate: 2.3034 t / t of coal
- Flow rate: 109.054 kmol / t of coal
- Molecular mass: 21.12
- Composition – mol %
  - H_2O 18.13
  - H_2 22.02
  - CO 49.23
  - CO_2 3.45
  - CH4 0.02
  - H2S 0.13
  - N2 + Ar 6.97
  - NH3 0.02
  - COS 0.02
  - HCN 0.01
  - Total 100.00

5.2 Oxygen entering the gasifier

5.2.1 Flow rate

The flow rate of oxygen is given as a function of the flow rate of coal. The flow rate of oxygen to feed rate ratio is 0.8122 t of O_2 / t of coal (Bituminous Douglas Premium).

5.2.2 Gas conditions

- Temperature: ambient = 15^{o}C
- Pressure: 4.8 MPa
- Purity: 95 % (exit of ASU and input to gasifier)

5.3 Nitrogen entering the gasifier

5.3.1 Flow rate

The flow rate of nitrogen is given as a function of the flow rate of coal. The flow rate of nitrogen to feed rate ratio is 0.2207 t of N_2 / t of coal (Bituminous Douglas Premium)

5.3.2 Gas conditions

- Temperature: 80 ^{o}C
- Pressure: 8.8 MPag
- Purity: 99.9% [*Shell personal communication June 2008*]

5.4 CO_2 entering the gasifier as coal transport gas instead of nitrogen

5.4.1 Flow rate

The flow rate of CO_2 is given as a function of the flow rate of coal. The flow rate of CO_2 should be taken as 2 x the rate of N_2 [*Shell personal communication Dec. 2008*].

5.4.2 Gas conditions

- Temperature: 80 ^{o}C [*Shell personal communication Dec. 2008*]
- Pressure: 5.00 MPag (higher than the pressure of the gasifier) [*Shell personal communication Dec. 2008*]

5.5 Gasifier availability and reliability

- Availability: 90%, including scheduled shut-down [*Shell IGCCH_CCS_DECARBIT_3SI*]
- Reliability: 97% excluding scheduled shut-down [*Shell IGCCH_CCS_DECARBIT_3SI*]

6 SHIFT REACTOR

6.1 General characteristics

The process considered is Sour Shift, with 95% CO conversion and typical H2O/CO ratio = 2.1 and pressure loss of 0.5 bar in each reactor (Haldar Topsoe). These values are references and other values can be used, if justified. Only Bituminous coal is considered here at this moment. Other fuels will be considered in future revisions of this document.

6.2 Syngas leaving the gasifier to acid removal or shift reactor

Please see section 5.1.

6.3 Syngas leaving the shift reactor

Conditions and composition are given here as an indication only. They should be calculated in each case and a reference to the calculation procedure should be given. The numbers given here were calculated by NTNU for the Decarbit Base Cycle:

- Pressure: 36.7 bara (NTNU Base Cycle)
- Composition in mol % (NTNU Base Cycle):
    - H_2 53.85
    - CO 1.73
    - CO_2 38.18
    - N_2 4.77
    - O_2 0.00
    - Ar 0.94
    - H_2S 0.31
    - H_2O 0.17
    - Other 0.05 (for reference only)

7 GAS TURBINE

This section provides a guidance for gas turbine performance calculations.

The typology of gas turbine considered is large-scale "F class" 50 Hz. The present (2008-9) state-of-the-art performance of these turbines is summarized in the Table 7.1, derived from manufacturers' data, as published in the Gas Turbine World – 2008 Performance Specifications.

Table 7.1 – Plant output, net plant efficiency, pressure ratio, turbine outlet temperature and specific work of large-scale gas turbines of the "F class"

Manufacturer and model	Plant Output	Net Plant Efficiency	Pressure Ratio	Turbine Outlet Temperature	Specific Work
	MW	%		(°C)	(kJ/kg)
Alstom GT-26[(1)]	289.1	39.1	33.4	615	451
GE 9371F	279.2	37.9	18.3	630	426
Siemens STG5-4000F	286.6	39.5	17.9	577	416

[(1)]GT with sequential combustion

The data refer to use of air (ISO conditions) as compressor inlet working fluid and natural gas fuel.

For the two models not adopting sequential combustion (GE 9371F and Siemens STG5-4000F), the nominal net power output, specific work and net efficiency of this class turbines are in the range of 280-285 MW, 416-426 kJ/kg and 38-39% respectively, while the pressure ratio and TOT vary between 17.9-18.3 and 577-630°C respectively.

Hence, a *"reference, average"* F-class large-scale gas turbine could be described by the following operating parameters and performance:

- Pressure ratio: 18.1
- Pressure drop:
    - Inlet filters: dp = 0.001 MPa
    - Exhaust: dp = 0.001 MPa (no HRSG)
    - Natural gas pressure at the combustor inlet: 2.31 MPa (5 bar above the compressor outlet pressure)
- Net efficiency= 38.5%
- Specific work (defined as gas turbine output divided by the compressor intake mass flow rate) = 420 kJ/kg
- Turbine Outlet Temperature (TOT) = 603 °C

A number of various models for gas turbine performance calculations are being used. No attempt is here made to prescribe a computational method, because there exists such a variety in modelling approaches. Turbine cooling is an example of a performance related issue, which is dealt with in various manners. Another example is the calculation of the compressor and turbine; for which a stage-by-stage analysis, maps or lumped model approaches are being used.

In order to be applied in simulating the gas turbine performance in capture CO_2 capture cycles, the models should have a built-in capability to correctly account for different working conditions, fuel properties, etc. Different models adopted for cooled expansion in the gas turbines can result in different temperatures and cooling flows: values used for the calibration of TIT (the term **turbine inlet temperature** (TIT) is assumed calculated as the mixing temperature of all cooling flows and the combustor exit flow) should be indicated as well as cooling flows (defined as mass flow rate of cooling air divided by the compressor intake mass flow rate).
A complete mass and energy balance should be provided, with thermodynamic conditions of the most representative flows.

Many CO_2 capture methods imply a more or less significant change in operating conditions for the gas turbine. Some of the changes make a big impact on the gas turbine performance, such as change of working fluid composition (e.g., oxy-combustion cycles) or a change in the fuel to much lower volumetric heating value (e.g., the H_2-rich fuel stream from an IGCC with CO_2 capture). If the gas turbine cycle to be evaluated is different compared to the air/NG gas turbine, the following is advised:

1. The computational model is validated to obtain the above mentioned *reference, average* performance (specific work, net plant efficiency, turbine outlet temperature) when operated at the conditions set above (ISO conditions, pressure ratio, pressure drops, air as working fluid and reference natural gas as fuel).
2. There is a description on the methodology applied for prediction with quite different operating conditions than for the air/methane gas turbine. This may include:
    a. General deviation of compressor and turbine efficiencies caused by fluid properties, number of stages, blade geometry
    b. Use of the choked nozzle equations for the turbine inlet relation between pressure, temperature and flow rate (evaluation of given/existing gas turbines).
    c. Turbine inlet temperature decrease/increase because of higher/lower heat transfer flux (as with the content of H_2O)
    d. Cooling flow variation to maintain the same maximum metal temperature of the turbine blades experienced with air/NG when operating under different conditions.
3. The new, modified mass and energy balance should be provided, with thermodynamic conditions of the most representative points.

8 STEAM CYCLE

8.1 Cycle Configuration

Steam cycles based on PC boilers are the preferred technology worldwide for power generation from coal, assuring high availability and the lowest cost of electricity. Ultra-supercritical live steam parameters (300 bar, 600/610 °C) are selected according to today state of the art large plants. Water pre-heaters produce boiler feed-water at 315 °C.

8.1.1 Fired boilers

8.1.1.1 Basic parameters – Bituminous coal

- One pressure level
- Conditions at boiler exit: 300 bar, 600 °C
- Single reheat: 50 bar, 610 °C
- Boiler efficiency: 95% for Bituminous coal

8.1.1.2 Pressure losses

- $\Delta p_{cold} = 3\%$ for each heat exchanger
- $\Delta p_{reheat,cold} = 10\%$
- $\Delta p_{steam\_pipe+valve} = 7\%$

8.1.1.3 Temperature losses

- From superheater / reheater to turbine: 2 °C

Natural circulation is considered.

8.1.2 Heat Recovery Steam Generator - HRSG

8.1.2.1 Basic parameters

- Triple pressure, single reheat
- Reheat: mix superheated IP steam with cold reheat steam before reheat
- $\eta_{HRSG} = 99.7\%$

8.1.2.2 Pressure losses

- $\Delta p_{HRSG-hot} = 3$ kPa
- $\Delta p_{HRSG-cold} = 3\%$ for each heat exchanger
- $\Delta p_{reheat-cold,tot} = 10\%$
- $\Delta p_{steam-pipe,valve} =$
    - HP 7%
    - IP 9%
    - IP 9% for reheat IP steam mixing
    - LP 12%

8.1.2.3 Temperature losses

- From superheater / reheater to turbine: 1kJ/kg (approximately 0.5 K)

8.1.2.4 Temperature differences

- $\Delta T_{steam-gas} = 25\ ^{o}C$
- $\Delta T_{pinch\_point\_gas-boiling\_liquid} = 10\ ^{o}C$
- $\Delta T_{gas-liquid} = 10\ ^{o}C$
- $\Delta_{approach-ECO} = 5\ ^{o}C$

Natural circulation is considered.

8.2 Condenser

- Natural draft cooling tower – water cooled steam condenser
    - Condenser pressure: 0.0048 MPa at saturation temperature of 26. ^{o}C
    - Cooling water pumping work: 0.5% of steam turbine power
    - Cooling water pressure: 0.2 - 0.25 MPa

  Saturated condensate is assumed at the condenser outlet.

8.3 Steam turbines

8.3.1 Isentropic efficiencies

- $\eta_{HP} = 92\%$
- $\eta_{IP} = 94\%$
- $\eta_{LP} = 88\%$

8.3.2 Pressure losses for steam extraction

- HP extraction pipe + preheater: 3%
- LP extraction pipe + preheater: 5%

8.4 Pumps

- Efficiency: 70%

9 HEAT EXCHANGERS

The specifications given here apply to heat exchangers not in the steam cycle.

9.1 Pinch points

- Gas / gas: 25 ^oC
- Gas / boiling or liquid phase: 10 ^oC
- Liquid / liquid: 10 ^oC
- Condensing / liquid : 3 ^oC

These values are given as guidance reference. Issues like metallurgy, size, pressure or composition may influence the heat transfer and there may be situations where very low temperature differences may be appropriate. So, other values can be used, if justified.

9.2 Pressure drop

Pressure drop in heat exchangers is strictly dependent on phase. Usually liquid phase pressure drop is absolute and does not depend on relative pressure of the liquid. However, considering the infinite number of possible cases and for simplicity in this report, relative pressure drop will be adopted also for liquid.

- Liquid phase pressure drop for cold and hot side: 0.04 MPa
- Gas phase pressure drop for cold and hot side: 2%

10 EFFICIENCY CALCULATIONS

10.1 Specific values

10.1.1 Mechanical efficiency:

$$\eta_m = 99.6\%$$

10.1.2 Generator efficiency:

$$\eta_G = 98.5\%$$

10.1.3 Auxiliary power:

η_{Aux} = estimated case by case

10.2 Power island

The efficiency of the power island shall be calculated using the following formula:

$$\eta_{net,PI} = \frac{(W_T + W_C)\eta_m \eta_g + W_{ST}\eta_m \eta_g + W_p + W_{aux}}{\dot{m}_f \; LHV}$$

$\eta_{net,PI}$	net efficiency of the Power Island	-
$\dot{m}_f$	fuel flow rate	kg/s
LHV	lower heating value	kJ/kg
W_T	turbine work, calculated as fluid enthalpy change	kW (>0)
W_C	compressor work, calculated as fluid enthalpy change	kW (<0)
η_m	mechanical efficiency	-
η_g	generator efficiency	-
W_{ST}	steam turbine work, calculated as fluid enthalpy change	kW (>0)
W_P	total pump work, feed water pumps, cooling water pumps, etc.	kW (<0)
$W_{aux,PI}$	total auxiliary work (power island only!)	kW (<0)

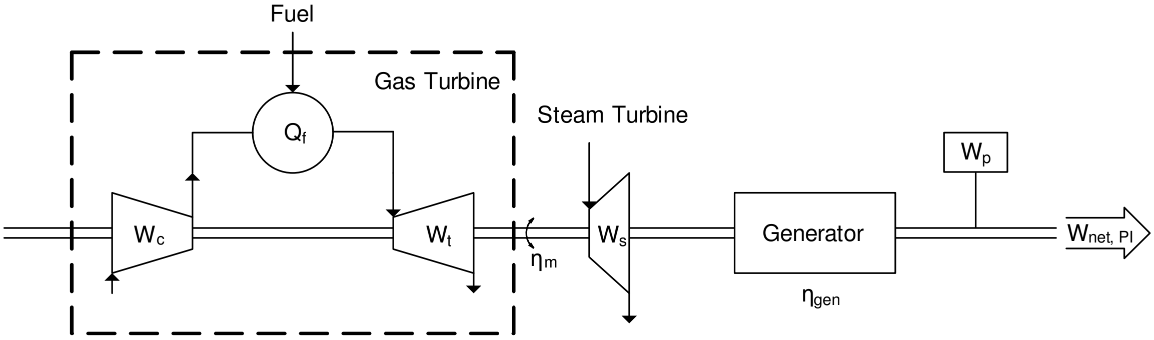

Fig. 10.1 – Nomenclature for the efficiency formula

11 CO_2 STREAM

In this chapter, the CO2 delivery conditions and compression process are defined. Pressure and temperature are adopted, as well as a standard composition. The final section describes the compression process. In principle, more than one destination can be given to the captured CO2 and for each destination different conditions and compositions may be appropriate. For simplification of comparisons, only one set of conditions and one set of composition are specified here.

11.1 Conditions

Most international studies on CO_2 capture are based on CO_2 delivery pressures 11.0 MPa – among others the studies made by IEAGHG - and in some cases 10.0 MPa. CASTOR and ENCAP projects have used 11.0 MPa, making results comparable to IEAGHG studies. The same pressure is adopted here.

- Pressure: 110 bar [following IEAGHG studies, ENCAP D1.1.1, pg. 27]
- Temperature : < 30°C [ENCAP D1.1.1 pg.27, for ISO conditions]

11.2 Composition

Tables 11-1 and 11-2 are adapted from ENCAP. They give values for storage in aquifers, oil reservoirs and the values adopted here.

Table 11-1 – Adopted limits in the CO_2 stream			
	Recommended for EBTF	**Aquifer**	**EOR**
CO2	> 90 vol %	> 90 vol %	> 90 vol %
H2O	< 500 ppm (v)	< 500 ppm (v)	< 50 ppm (v)
H2S	< 200 ppm (v)	<1.5 vol %	< 50 ppm (v)
NOx	< 100 ppm (v)	NA	NA
SOx	< 100 ppm (v)	NA	<50 ppm (v)
HCN	< 5 ppm (v)	NA	NA
COS	< 50 ppm (v)	NA	< 50 ppm (v)
RSH	< 50 ppm (v)	NA	> 90 vol %

Note: 1 vol % = 10000 ppm (v) - NA = not available

Table 11-2 – Adopted limits in the CO_2 stream - non-condensable components			
	Recommended for EBTF	**Aquifer**	**EOR**
N_2	< 4 vol % *	< 4 vol % *	< 4 vol % *
Ar	< 4 vol % *	< 4 vol % *	< 4 vol % *
H_2	< 4 vol % *	< 4 vol % *	< 4 vol % *
CH_4	< 2 vol %	< 4 vol % *	< 2 vol %
CO **	< 0.2 vol %	< 4 vol % *	< 4 vol % *
O_2 ***	<100 ppm vol	< 4 vol % *	<100 ppm vol

Note: * - $x + \Sigma x_i < 4$ vol % = total content of all non-condensable gases
** - health and safety issues
*** - to avoid ignition

11.3 Compression

As said before, a final pressure of 11 MPa is adopted here. The compressed CO_2 should be cooled to a temperature corresponding to cooling water temperature at inland site at ambient temperature 15°C and 60% humidity (according to ISO-conditions Section 2.1) plus appropriate pinch. This means that the CO_2 should be cooled down to below 30°C.

This section describes how CO2 compression is to be carried out. A flow diagram is shown in Fig. 11.1. Energy requirement for CO2 compression is estimated, so that net power plant efficiency calculations can be obtained without making simulations of the CO2 compression. The total electricity requirement for CO_2 compression from 0.15 MPa to 11.0 MPa is estimated here as 0.34 MJ/kg CO_2 (wet base). This is the result of a calculation example and different values may be found and used. They should be justified. The energy requirement for CO_2 compression may be influenced, for example, by the amount of impurities.

Three compressor stages with inter-coolers up to 8.0 MPa are considered, with the discharge pressure for each stage as specified in Fig. 11.1:

- Compression stage 1: 0.435 MPa
- Compression stage 2: 1.865 MPa
- Compression stage 3: 8.0 MPa

Polytropic efficiencies are adopted as:

- Compression stage 1: 80%
- Compression stage 2: 80%
- Compression stage 3: 75%.

The efficiency of the compressor driver is defined as 95%.

For the pumping of dense CO2 from 8.0 MPa up to the end pressure, pump efficiency of 75% and driver efficiency of 95 %.should be considered.

The temperature change in the process is adopted as:

*Inter-cooling to **18** (cooling water temperature) +**10** (cooling water temperature rise) = **28** ^{o}C*

Pressure loss in all heat exchangers is shown in Fig. 11.1.

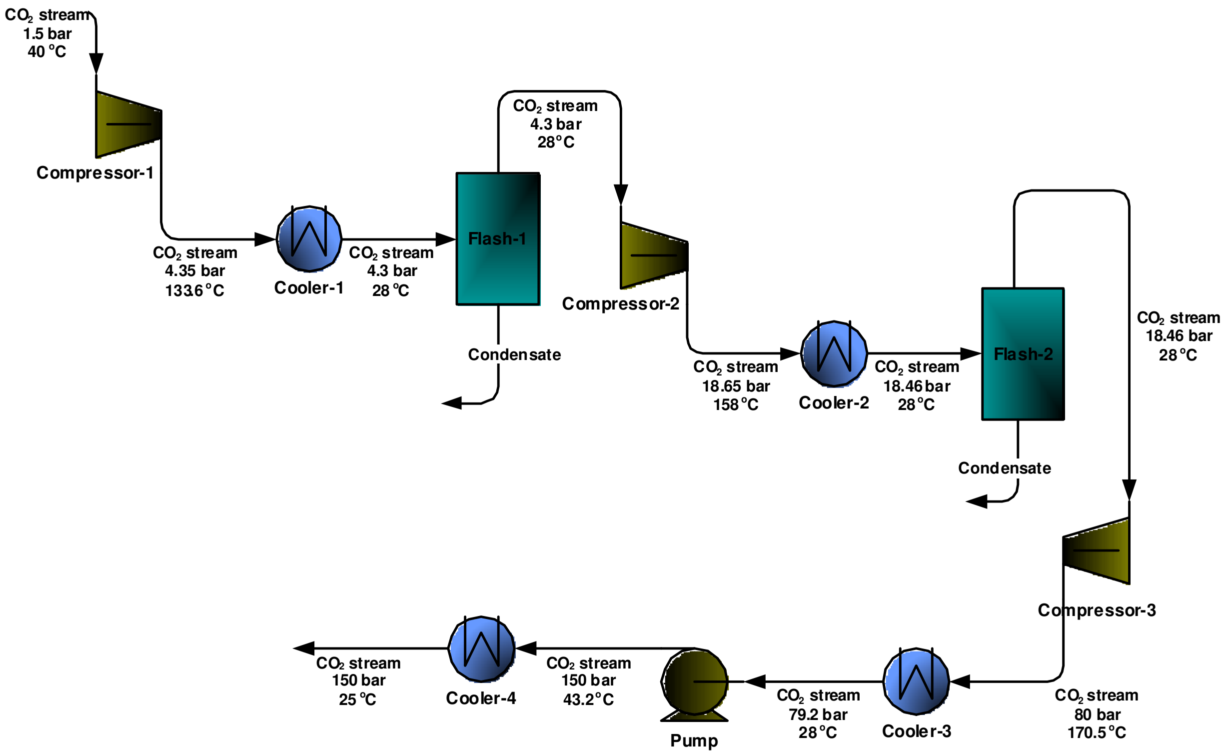

Fig. 11.1 – Flow diagram of CO_2 compression

12 EMISSION LIMITS FROM SOLID FUELS

12.1 Emissions to air

Table 12.1 is extracted from the EC Document 'Integrated Pollution Prevention and Control Reference Document on Best Available Techniques for Large Combustion Plants' – July 2006 (http://eippcb.jrc.ec.europa.eu/pages/Factivities.htm):

Table 12.1 – Emission limits according to EC guidelines for large combustion plants

Component	Presence	Comments
SO_2	20-150 mg/m^3	BAT: FGD scrubber – efficiency up to 98%
NOx	90-150 mg/m^3	BAT : combustion mods _ SCR
Particles	5-10 mg/m^3	BAT: electrostatic precipitator or fabric filter + wet scrubber
O_2 dry, daily average excluding start-up and shut-down	6%	Emission concentrations reported as daily averages, excluding start-up and shut-down, at a reference oxygen concentration of 6% on a dry basis.

For this Common Framework, the average values of the numbers in Table 12.1 are adopted and given in Table 12.2:

Table 10.2 – Emission limits adopted in this Common Framework

Component	Presence	Comments
SO_2	85 mg/m^3	BAT: FGD scrubber – efficiency up to 98%
NOx	120 mg/m^3	BAT : combustion mods _ SCR
Particles	8 mg/m^3	BAT: electrostatic precipitator or fabric filter + wet scrubber
O_2 dry, daily average excluding start-up and shut-down	6%	Emission concentrations reported as daily averages, excluding start-up and shut-down, at a reference oxygen concentration of 6% on a dry basis.

13 ECONOMIC ASSESSMENT CRITERIA

13.1 Introduction

The viability of the selected novel CO_2 capture cycles is not only determined by the favourable technical performance characteristics but also depends strongly on the overall economic attributes. The economic assessment comprises different stages. In the initial stage, a set of assumptions are produced in order to evaluate the economic viability of the suggested cycles on a consistent basis. Subsequently, the economic assessment of the base case systems with and without a CO_2 capture is carried out. The economic attributes of all the novel cycles are measured against these reference plants. The economic assessment consists mainly of bottom-up cost estimations, variable cost extrapolations and breakeven electricity selling price calculations. This systematic approach is also applied to the selected novel systems with the additional task of estimating the costs of the new components and the impact on the overall financial system performance. The economic viability of the selected cycles is primarily measured through the CO_2 avoidance costs and the breakeven electricity selling prices. However, other factors indirectly related to the economics, such as cycling behaviour, reliability and flexibility issues should be discussed. Finally, a number of sensitivity analyses are performed to disclose the effect of some mostly volatile parameters on the economic characteristics of the cycle.

This report outlines the relevant assumptions conducive to assessing the economics of the novel technologies. Based on the stipulated values, it should be possible to extrapolate the lifetime cost of the selected systems. The total capital cost assessment is implemented according to the step-count exponential costing method using dominant or a combination of parameters derived from the mass and energy balance computation. The fixed and variable operating and maintenance costs are extrapolated as a function of material, fuel and energy flow along with relevant values specified in the assumption. Following the total capital cost assessment, the net present value computation will be applied to determine the breakeven electricity selling prices of the selected cycles. The variability of some relevant assumptions necessitates the implementation of a series of sensitivity analyses as part of the impact assessment.

13.2 Economic boundary conditions

The economic boundary conditions include the main assumptions related to the power plant life cycle from construction to decommissioning. All the economic assessments are based on the reference year 2008 – the start of the project. The economic ups and downs of this time, however, can make it difficult to carry out the economics on the same level. On this ground, an average Chemical Engineering Plant Cost Index (CEPCI) of 576% is assumed for the year 2008 (100% for 1958, see Fig. 13.1). Suggestions to set the reference time to year 2015 or 2020 – it is assumed the technology may be available by that time – were rejected since the long-term future economic developments are hard to predict. For this period, an annual average exchange rate of €0.683/\$ (€1.258/£) is assumed.

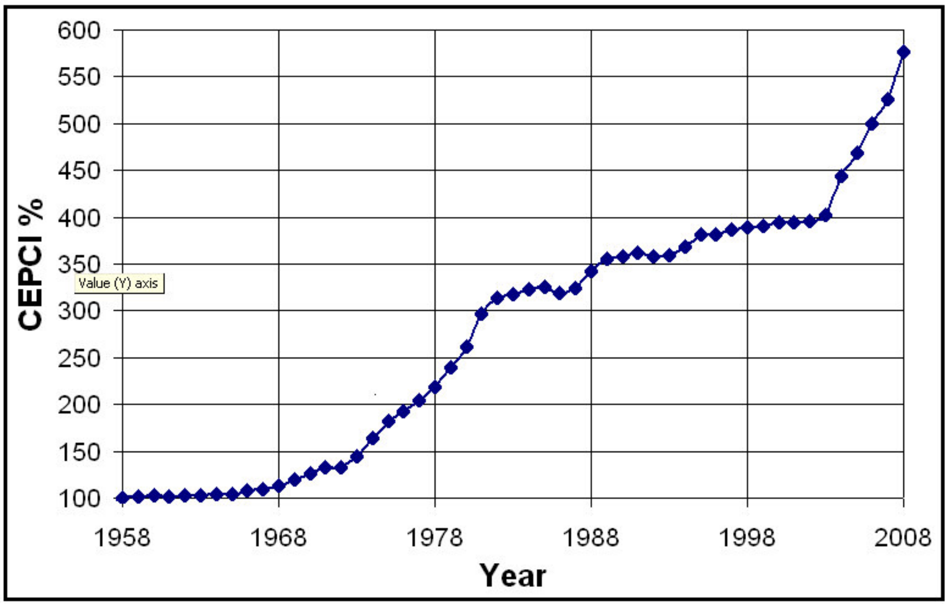

Fig. 13.1 – Chemical Engineering Plant Cost Index (1958-2008)

The power plant design lifetime is limited to 25 years. However, the economics can be substantially improved if the lifetime of the power plant components such as the gas turbine could be extended over the designed expectancy. To study the impacts on the economics, it is recommended to perform a series of sensitivity analyses, considering for example 40 years for coal and 15 years for natural gas. The expected membrane lifetime is set to a default value of eight years with a range of ±50% unless specified explicitly by SP2 and SP3. Hence, the sensitivity analysis covers a value between 4 and 12 years. It is reasonable to assume a plant construction time of four years including the commissioning phase for coal and lignite fed systems and 3 years for natural gas cycles. The annual budget allocation for the plant construction is set according to the following table:

Table 13.1 – Annual allocation of finances		
Year	Allocation 3 years	Allocation 4 years
1	40%	20%
2	30%	30%
3	30%	30%
4	0	20%

13.3 Financial parameters

In the financial analysis of the project, an average discounted cash flow rate (DCF) of eight percent is used. This hurdle rate is established to compensate for any investment risks and shows the loss of the project value over time (equity rate). The discounted cash flow also incorporates the cost of the capital (interest rates) and inflation rates. As part of the sensitivity analysis, DCF variations of ±50% are applied in this project to make up for any future uncertainties (DCF: 4-12%). Corporate and emission taxes vary significantly across member states and are inconsistent during the project life. On this ground, the economics of all the cycles are based on a pre-taxation rate. Similarly, the level of depreciation is excluded from this study.

13.4 Capital investment

The calculation of the engineering and procurement costs (EPC) is carried out in a bottom-up approach using the exponential costing method. EPC includes the costs of all the construction works (for example: piping works, civil and planning costs), installed equipment pieces and raw materials. All the costs are adjusted to the price level of the year 2008. The development costs are not incorporated in this study. The total capital investments consist of EPC, indirect costs and working capitals as well as contingencies, whereas the capital costs are only the sums of EPC and of indirect costs. The indirect expenditures include the costs for the yard improvement, service facilities and engineering costs as well as the building and sundries. The values are given in Table 13.2 as a percentage of EPC. The working capital and contingency levels – known as owner's costs – are fixed to 15% of the capital cost (EPC+ indirect costs) for all the technology options.

Table 13.2 – Indirect costs

Indirect costs	% of EPC
Yard improvement:	1.5%
Service facilities	2%
Engineering/consultancy cost	4.5%
Building	4%
Miscellaneous	1%

13.5 Main operational parameters

The selected cycles are designed to operate at a base load power. However, the experience has shown that, due to unexpected technical issues in the first years of operation, higher capacity factors need to be built up gradually. It is assumed that after two years of operation a capacity factor of more than 85% can be achieved. For the first and the second year of operation after the completion of the constructions, capacity factors of around 40% and 65% are presumed respectively.

Although the mine-mouth coal prices have been stable over the last years, the market costs have risen significantly. The price for the bituminous coal and lignite is specified at €3/GJ and €1.2/GJ respectively. The sensitivity analysis covers a variance of -50% to + 50% (€1.5/GJ-€4.5/GJ for bituminous coal and 0.6-1.7 for lignite). The natural gas price is set to €6.5/GJ with a variation between €4/GJ and €9/GJ. Although there are no provisions for natural gas fired cycles in DECARBit, however, a small amount of natural gas utilisation needs to be considered for the power plant start-up and cycling. The costs of the main consumables are listed in the table 13.3 below:

Table 13.3 – Cost of main consumables	
Consumable	Cost
Clean water	€6/m^3 (range €4 m^3 -€8 m^3)
Cooling water	€0.35 /m3
Ash disposal	€0-32/t (no cost assumed if the ash could be used for construction or mining)
Limestone	€36/t (€24-48/t)

13.6 Main economic performance characteristics

The breakeven electricity selling price (BESP) is considered as the main economic performance characteristics of the selected cycles. This parameter captures the total capital cost of the plant and all the operating and maintenance costs. The sensitivity analysis should disclose the impact of a number of volatile variables on BESP. The most important variables are the specific investments of the selected power plants, discounted cash flow rates and coal prices as well as capacity factor variations and the operating and maintenance costs.

APPENDIX A - THERMODYNAMIC PROPERTIES

A.1 Air

Equation of state for air by Soave-Redlich-Kwong or similar.

A.2 Pure CO_2

- Equation of state for CO2 by Span and Wagner (1996)
- Viscosity: Fenghour et al., 'The viscosity of carbon dioxide', Journal of Physical and Chemical Reference Data, 1998, 27(1): 31-44.

A.3 Steam

International Association for Properties of Water and Steam (IAPWS)-IF97.
Wagner et al., 'The IAPWS Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam', ASME J. Engineering Gas Turbines and Power, 122, 150-182, 2000.

APPENDIX B - FLUX CALCULATIONS FOR CO_2 CAPTURE MEMBRANES

Selectivity of a membrane of a component A with respect to a component B (α) is defined as

$$\alpha = \frac{P_A}{P_B} \qquad \text{B.1}$$

where P_A and P_B are the permeabilities of components A and B and are given in m^3(STP)m/(m^2 h bar).

The driving force in membrane separation is the difference in partial pressures over the membrane. The flux of a component A across the membrane can be expressed as:

$$\frac{\dot{q}_P y_A}{A_m} = J_A = \frac{P_A}{l}\left(\hat{p}_A^{feed} - \hat{p}_A^{perm}\right) \qquad \text{B.2}$$

where:

$\dot{q}_P$ = volumetric flow of the permeating gas in m^3 (STP) / h
y_A = fraction of the permeating gas in the permeate
A_m = membrane permeation area in m^2
l = thickness of the membrane in m
$\hat{P}_A^{feed}$ = partial pressure of component A in the feed stream in bar
$\hat{P}_A^{perm}$ = partial pressure of component A in the permeate stream in bar