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Hypogen pre-feasibility study. Final report

Peteves, S.D.; Tzimas, E.; Starr, F.; Soria, A.; Calabro, A.; Deiana, P.; Mario, F. Di; Fiorini, P.; Girardi, G.; Iacobazzi, A.

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HYPOGEN PRE-FEASIBILITY STUDY

Final Report

Prepared by

ENEA, Italy

Fraunhofer ISI, Germany

Risø National Laboratory, Denmark

A study commissioned and guided by the
European Commission, DG Joint Research Centre
Institute for Energy and Institute for Prospective Technological Studies

Coordinated by S.D. Peteves, E. Tzimas, F. Starr and A. Soria

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ENEA

Antonio Calabrò, Paolo Deiana, Francesco Di Mario, Paolo Fiorini, Giuseppe Girardi, Agostino Iacobazzi, Stefano Stendardo

Fraunhofer ISI

Clemens Cremer, Ulrike Hasenauer, Peter Radgen

Risø National Laboratory

Janet J. Bentzen, Birte H. Jørgensen,

FOREWORD

The Sustainable Energy Technologies Reference and Information System (SETRIS) of the DG JRC, specifically its actions from the Institute for Energy (IE) and the Institute for Prospective Technological Studies (IPTS) commissioned this study on the HYPOGEN (HYdrogen POwer GENeration) concept, to its ESTO network, upon a request from its partner DG RTD/J (Sustainable Energy Systems). This report presents the work of the ESTO team that took place in the May-to-October 2004 period under the guidance of SETRIS.

The report covers the co-production of hydrogen and electricity from fossil fuels and the capture and storage of the carbon dioxide generated in the process. It identifies the main technological, socio-economic, financial, legal and environmental constraints. It has stimulated much thought and discussions on the subject during the two workshops (kick-off & dissemination/validation) organized in 2004 in which a large number of relevant stakeholders and the Services concerned (DGs JRC, RTD and TREN) participated. The study is very thorough and comprehensive. However, certainly in terms of the fuel choices and the plant designs proposed, this report should not be regarded as “blueprint” for the design and construction of a HYPOGEN facility.

In conjunction with this study SETRIS (IE) has been conducting its own analysis of the HYPOGEN concept. The coordinators of this report therefore consider that any design proposal should make a strong case for the choice of fuel, taking into account security of supply, environmental benefits and competitiveness of European industry. Furthermore, it seems likely that off-the-shelf fossil fuel generating plants and processes for producing hydrogen for the chemical industry may require modification. Specifically, the coordinators consider that a HYPOGEN Test Facility should have the flexibility to switch the ratio of hydrogen to electricity production over a relatively short time. This flexibility will meet future requirements of an energy system where electricity from renewable energy sources will be a dominant factor. The HYPOGEN project may require sustained research, development and demonstration of specific technologies and critical components for the facility of the HYPOGEN programme.

SETRIS intends to publish its own views on HYPOGEN during the first half of 2005.

Coordinated by

S.D. Peteves, E. Tzimas, F. Starr and A. Soria

DG – JRC, IE and IPTS

26 January 2005

Contents

List of figures

List of tables

EXECUTIVE SUMMARY

The Quick-start Programme of the European Initiative for Growth identifies the Hydrogen Economy as one of the key areas for investment in the medium term (2004-2015). Two hydrogen related programmes (or projects) have been outlined:

- **Hydrogen Communities (HyCom).** The creation of a limited number of strategically sited stand-alone “hydrogen communities”, producing hydrogen from various primary sources, mostly renewables, and using it for heat and electricity production and as fuel for vehicles, is the main goal of this project (with an indicative budget of ca. 1.5 billion EUR).
- **Hydrogen and Power Generation (Hypogen).** A major component will be the first large scale test facility for production of hydrogen and electricity from de-carbonised fossil fuels, with geological storage of CO_2 (with an indicative budget of ca. 1.3 billion EUR).

In April 2004, the European Science and Technology Observatory (ESTO) Network of the DG Joint Research Centre of the European Commission made a call to conduct two pre-feasibility studies of HyCom and Hypogen. The studies were awarded to a consortium of ENEA (I), Risø National Laboratory (DK) and Frauenhofer ISI (D). The studies were led by DG-JRC and conducted during the period 1 June 2004 to 1 October 2004. The Hypogen pre-feasibility study has been elaborated jointly by ENEA and Fraunhofer ISI with contributions from the Risø National Laboratory. Risø National Laboratory has been responsible for the HyCom pre-feasibility study supported by contributions from Fraunhofer ISI and ENEA. A kick-off meeting was held in Brussels with selected stakeholders on 24 and 25 May 2004 to take into account the views and experiences from key on-going EU projects. Draft summary findings were presented and discussed at seminars in Brussels on 18 October 2004 and 29 October 2004. Comments from these seminars have been considered in the final reports as well as from the project sponsors, the institutes for Energy and for Prospective Technological Studies of DG JRC.

This report presents the results from the pre-feasibility study on Hypogen. The results from the HyCom study are presented in a separate report.

The **objectives of the pre-feasibility study** for the Hypogen Initiative were more specifically:

- To provide an overview about technological options and financial, regulatory and other barriers;
- To shed some light on key issues of the programme, making a preliminary evaluation of its feasibility;
- To provide options and to make preliminary recommendations.

The results from the study are expected to stimulate discussions and exchange among all those involved for leading eventually to a more precisely defined concept of Hypogen and for providing guidance to the European Commission in its planning of the next steps of the Initiative.

The main conclusions and recommendation from the study address:

- The context for Hypogen;
- The technology options;
- The non technical barriers;
- The potential impacts, possible financial and juridical implications and key problems for long term success.

The context of Hypogen

The de-carbonisation of fossil fuels via CO_2 capture and storage can play, in the medium-long term, an essential role in the development of a sustainable energy system in Europe, where renewable energy sources will be increasingly used within an energy mix of secure energy supply. In this context, the Hypogen programme will give an important contribution by demonstrating the technical feasibility and economic viability of producing hydrogen and electricity from fossil fuels with near-zero CO_2 emissions and promoting the development of hydrogen as an energy carrier. Moreover, Hypogen will improve the competitiveness of the European industry, fostering the development of advanced technologies with a large export potential.

The achievement of the ambitious goals of the programme requires huge efforts in order to focus on the necessary resources and competences, involving the key industrial players, and establishing useful synergies with other European and national programmes.

The production of hydrogen and/or electricity via the de-carbonisation of fossil fuels is gaining a growing attention in the frame of the European and international programmes. In Europe Hypogen represents an important element of the strategy for the development of a sustainable energy system and is strictly linked to other projects planned in the field of hydrogen and clean power generation from fossil fuels. The experience and the technologies developed within these projects together with the possible synergies will give an essential contribution to the success of Hypogen. The integrated production of both electricity and hydrogen from fossil fuels, with the capture of the CO_2 generated in the process, is also developed in the frame of other international programmes. The most important of them is FutureGen, a large demonstration project launched by the US government in February 2003, whose fundamental goal is to overcome the environmental constraints associated with the production of electricity and other forms of energy from coal.

The development of the de-carbonisation of fossil fuels for electricity and hydrogen production in a liberalised energy market requires the availability of suitable technologies and a framework that promotes the investments in these environmentally compatible energy systems, making their higher costs affordable at present and future market conditions. Both aspects have been analysed in this study.

Technology options

Several technological options exist for Hypogen, mainly depending on the solutions adopted for:

- hydrogen production (fuel and process);
- CO_2 capture and storage;
- electricity production (thermal cycle).

Hydrocarbons, especially natural gas, are the dominant source of hydrogen today in refining and other industrial applications and are generally the lowest cost option. Different processes are employed (steam reforming, autothermal reforming, partial oxidation) and their technologies are commercially mature. The production of hydrogen from coal can be based on a variety of gasification processes (fixed bed, fluidised bed, entrained flow). Even in this case the technology is mature but the system is more complex and the cost of hydrogen produced is higher than that from natural gas. The deployment of CO_2 capture and storage at these plants will increase the cost of hydrogen by 15-20%. However, even without considering the CO_2 capture, hydrogen is actually not competitive in the transport sector.

Among the different options for CO_2 capture (post combustion, pre combustion, oxyfuel combustion), the pre combustion capture is the only way where hydrogen, or an hydrogen rich gas, could be produced. Since the CO_2 concentration is relatively high (about 30%), it can be separated using physical solvents. This process is less energy intensive than using chemical solvents as those adopted in the post combustion capture.

The choice of the transportation system for the CO_2 (pipeline, ship, combined) will largely depend both on the site chosen for the facility and on the site chosen for storage. The existing information indicates that there are no technical obstacles that could put the whole transportation system at risk, even if the impact of the transportation costs and the permitting process has to be considered for the Hypogen project.

The feasibility and the proof of a permanent CO_2 storage are critical to the success of the de-carbonisation approach and represent a high risk associated with the success of Hypogen. Among the several options actually under discussion, the storage in geological formations, and, in particular, the storage in oil and gas fields and in aquifers, seems the most promising solution for Hypogen. In particular, storage in connection with enhanced hydrocarbons recovery (EOR) offers the possibility to improve the economics of the carbon capture and storage and will probably cause the least problems with undeveloped regulations for CO_2 storage.

A part of the hydrogen, or hydrogen rich gas, produced in Hypogen is utilized for power generation. The combined cycle is the most advanced and efficient solution. The integration of the production of hydrogen rich gas from coal and heavy oils (syngas) with a combined cycle, without CO_2 capture, is already used in existing plants (Integrated Gasification Combined Cycle, IGCC), with electrical efficiencies ranging between 40 and 42% and very low emissions of pollutants. The further development of this type of plants with a pre combustion CO_2 capture is the most promising solution for the production of de-carbonised hydrogen and electricity from coal in the medium-long term. In order to make this technology widely competitive in the electricity market significant improvements are needed: i) the increase of the plant efficiency; ii) the reduction of capital cost; iii) the improvement of reliability and operating flexibility.

Another option for the plant configuration is the integration of CO_2 capture and combined cycle with production of hydrogen from natural gas. This solution, completely new in the field of power generation but at the state of the art in the chemical industry, can rely on commercial technologies and lead to a system with a higher efficiency and lower investment and operating costs.

In both cases the deployment of pre combustion CO_2 capture will increase the investment cost (by 30-40% for IGCC systems and 70-80% for natural gas systems) and the cost of electricity (by 30-40%), with a reduction of the plant efficiency of about 6-12 points. A comparison of estimated capital costs and efficiencies for natural gas and coal systems with pre combustion decarbonisation is summarized in the following table:

	Natural gas	Coal
Capital cost [€/kW]	1,000 - 1,100	1,800 - 1,900
Efficiency (LHV) [%] (2004)	45 - 48	36 - 38
Efficiency (LHV) [%] (2010-2015)	50 - 52	40 - 42

The cost of hydrogen and electricity largely depends on the assumptions made for fuel cost. The future trend of this cost, and the security of supply, are among the critical factors to be taken into account in the fuel choice for Hypogen plant.

Moreover, a key issue is the utilization in these systems of a gas with different characteristics in thermal cycles, which requires some changes and optimisation in the power plant, and, in particular, the availability of high efficiency gas turbines with a sufficient size, able to operate with hydrogen rich gas.

Plant site

Apart from the selection of the technology options, the choice of the plant site is another key issue for the success of the programme. This choice has to take into consideration, besides the typical aspects of the conventional plants, some critical factors related to the CO_2 storage and the hydrogen market:

- Hypogen has to be located inside or near an area where the hydrogen demand is or is going to become comparable with the productive capacity of the plant (taking into account also the possible industrial applications);
- an appropriate site for CO_2 storage must be available, such as: i) an EOR application, with an income that counterbalances, at least in part, the transportation cost at a significant distance from the plant; ii) a depleted gas field; or iii) a saline aquifer not too far from the plant;
- the area selected should present a favourable framework in terms of public acceptance, regulations for innovative part of the facility, availability of incentives for de-carbonised hydrogen and electricity, and availability of public regional or national funds.

Non technical barriers

The development of a favourable framework for de-carbonised hydrogen and electricity production is of primary importance for the implementation of a full scale demonstration project, like Hypogen, and for the participation of key industrial players. The creation of this framework presents a high risk and largely depends on:

- the promotion of measures for the reduction of greenhouse gas emissions;
- the overcoming of some critical barriers related to CO_2 storage (e.g. legal and regulatory aspects, public acceptance);
- the development of a hydrogen market for stationary and transport applications.

Actually, the promotion of measures for the reduction of greenhouse gas emissions (emission trading) is a long term process that presents a lot of uncertainties. Consequently, it is hardly feasible to found the economics of the Hypogen plant only on the financial contributions resulting from these measures. However, Hypogen could benefit by incentives for the de-carbonised hydrogen and electricity production, put in place through the tariff structure (like tax exemption and green certificates). A high risk is also linked with the legal permission procedures and with the public acceptance of CO_2 storage. In order to reach this task, an effort has to be done by the policy makers and the stakeholders to foster the development of the required regulations and to spread the information in this field. Finally, the development of hydrogen as an energy carrier requires the overcoming of several technical and socio-economic barriers. Even if a large effort is spent in this field in Europe, it is difficult to estimate the hydrogen demand in the period of Hypogen operation (2012-2015). In this situation, Hypogen should have the flexibility in the shares of output products (hydrogen and electricity). Apart from the application on the vehicles, the supply of hydrogen for other markets (e.g. industrial applications) will constitute an important option for the use of the hydrogen produced in the short term.

Hypogen impacts and possible financial and juridical implications

The construction and successful operation of Hypogen will play a fundamental role in verifying the feasibility of de-carbonisation of fossil fuels for hydrogen and electricity production, with a strong impact on:

- the development of a sustainable European energy system;
- the development of hydrogen technologies and market, particularly in the transport sector;

- the competitiveness of the European industry;
- the employment in the field of hydrogen components and systems manufacturing, operation, maintenance and servicing and in the power plant sector.

Hypogen programme will require large investment and will present high technical and financial risks. A strong public/private partnership has to be put in place to raise the necessary capital for the construction and operation of the facility, with the utilization of a variety of funding sources (European, national and regional) and financing instruments, besides incentives for the utilization of de-carbonised hydrogen and electricity. Industry will however only take the risk, if the technology is seen cost effective in the mid term.

The huge effort required by Hypogen, and the complexity of the programme, suggest that a consortium for the construction and operation of the facility has to be formed. This consortium should include several utilities and technology suppliers from different European Countries and should have strict connections with the main public organizations involved, both European and national, through an appropriate public/private partnership.

Preparatory phase of the programme

Many technical, economical, social and political challenges must be addressed in the preparatory phase of the programme, in order to identify the best technology options, financing mechanisms, juridical structure and site, to clarify the environmental and public acceptance issues and to develop an appropriate regulatory framework. Moreover, the identification of possible synergies with other national and European projects is of great importance in order to co-ordinate the main initiatives carried out in this field in Europe and to optimize the utilization of the considerable resources required.

In order to do this, a detailed feasibility study is needed, together with actions concerning:

- R, D & D support activities,
- Site selection, monitoring and characterization,
- Permitting,
- Public information.

In order to go on with the programme as quick as possible, sufficient funding should be provided for the feasibility study and other support activities under the 6th Framework Programme.

1. SCOPE OF THE PRE-FEASIBILITY STUDY

In November 2003, the European Commission launched the Quick-start Programme for European Initiative for Growth with 56 projects: 31 in transport, 17 in energy, and 8 in communications network, R&D and innovation. The common nominator for these projects was that they were ready to start immediately, and would have a positive impact on growth, employment, and protection of the environment (Speech by President of the European Commission Romano Prodi, 11 November 2003). An annual investment of around 10 billion EUR was expected, to come from public and private sources. Although the contributions from the public and private sector might vary from sector to sector and from project to project, an overall 60/40 split between public and private funding was estimated.

The Quick-start Programme identified the Hydrogen Economy as one of the key areas of investment with two initiatives planned in the area over a 10-year period (2004-2015):

- **Hydrogen Communities (HyCom).** The creation of a limited number of strategically sited stand-alone "hydrogen communities", producing hydrogen from various primary sources, mostly renewables, and using it for heat and electricity production and as fuel for vehicles, is the main goal of this project (with an indicative budget of ca. 1.5 billion EUR).
- **Hydrogen and Power Generation (Hypogen).** A major component will be the first large scale application for production of hydrogen and electricity from de-carbonised fossil fuels, with geological storage of CO_2 (with an indicative budget of ca. 1.3 billion EUR).

In March 2004, the Commissioner for Research Philippe Busquin presented these ambitious initiatives to boost a transition from a fossil-based economy to a hydrogen-based one:

> *"Our aim is clear: to develop cost-competitive, sustainable energy systems for future generations. Although hydrogen represents a bridge to a sustainable energy future, it is also a revolutionary technology. It signals major changes in the way we produce, distribute and use energy. Complex transition strategies have to be worked through, involving heavy investments and building consensus between key players."* (Speech at "Fuels for a Future Generation", 18 March 2004, Brussels).

An ESTO call was made in April 2004 to simultaneously conduct **two pre-feasibility studies of HyCom and Hypogen**. The main boundary condition for the studies was the necessity (expressed clearly by the final customer in DG RTD) of having a final deliverable ready to contribute to a successful start of the Quick Start Programme, which is organised under the 6th Framework Programme call for proposals of September 8th 2004. This necessity precluded a large ESTO consortium, for in this occasion a reduced team would prove easier to coordinate.

Following an evaluation process, the studies were awarded in May 2004 to a consortium of ENEA (Italy), Risø National Laboratory (Denmark), and Fraunhofer ISI (Germany).

The pre-feasibility studies address the key issues concerning the definition and development of the two initiatives, HyCom and Hypogen, in order to make a preliminary evaluation of their feasibility. To this end, technical, economic, social and environmental aspects are considered, with the aim of clarifying the broad content of the initiatives, their complementarity and possible contribution to sustainable economic growth.

The studies have been organised with ENEA as Operating Agent for the two studies. The Hypogen pre-feasibility study has been elaborated jointly by ENEA and Fraunhofer ISI with contributions from the Risø National Laboratory. Risø National Laboratory has been responsible for the HyCom pre-feasibility study supported by contributions from Fraunhofer ISI and ENEA.

The studies have been conducted in the period 1st June 2004 to 1 October 2004. A kick-off meeting was held in Brussels with selected stakeholders on 24 and 25 May 2004 to take into account the views and experiences from key on-going EU projects.

The findings of the studies have been compiled in two separate reports, one dealing with Hypogen, the second dealing with HyCom.

This report presents the results from the pre-feasibility study on Hypogen.

The Hypogen Study

More specifically, the study for the Hypogen Initiative has the following aims:

- To provide an overview about technological options and financial, regulatory and other barriers;
- To clarify key issues of the programme;
- To start to engage key players;
- To provide options and recommendations.

The results from the study are expected to stimulate discussions and exchange among all those involved for leading eventually to a more precisely defined concept of Hypogen and for providing guidance to the European Commission in its planning of the next steps of the Initiative.

Apart from this initial chapter on the scope of the pre-feasibility study, this report consists of six chapters:

Chapter 2 describes and analyses the context for the Hypogen Initiative. In the first part, the role and objectives of Hypogen in the framework of the development of a sustainable European energy system are described. The second part gives information about similar international programmes and an overview of the most important European projects relevant to Hypogen.

Chapter 3 describes the possible technology options for Hypogen, analysing the alternatives for: i) hydrogen production from fossil fuels (natural gas, heavy oils and coal); ii) carbon capture, transport and storage; iii) thermal cycles for power production; iiii) auxiliary systems (gas clean up, O_2 production).

Chapter 4 analyses some social and economical factors that could promote or hinder the creation of a favourable framework for Hypogen. In the first part the impact on Hypogen of factors related to carbon capture and storage, such as the European Emission Trade Scheme, legal and regulatory aspects and public acceptance, is presented. The second part focuses on market development for de-carbonised hydrogen and electricity.

Chapter 5 analyses the main issues related to the development of Hypogen programme: the choice of fuel and plant configuration, the potential socio-economic impacts, the possible synergies with other European projects, the preparatory actions that will be needed, the possible financing sources and juridical structure.

Chapter 6 describes the main risks and success factors associated with the programme, considering technical, financial and socio-economic aspects.

Chapter 7, in conclusion, gives some recommendations concerning the key issues of the programme and outlines the most important actions that should be started in near term to verify in detail the technical and economical feasibility of Hypogen.

An appendix, with a preliminary analysis of a possible coal-based Hypogen plant, is attached.

2. HYPOGEN IN CONTEXT

2.1 Hypogen in the European energy system

The European energy system faces a number of significant challenges over the coming decades, as highlighted in several studies, like, for example, the Green Paper on European strategy about energy [EU, 2001]. The major concerns in this sector are the security and economy of energy supply and the reduction of greenhouse gas emissions associated with climate change.

According to the Green Paper forecast that reflects the continuation of existing trends and policies for the next 30 years, the energy consumption is expected to rise by 25 % between 1998 and 2030 in 30 European countries (EU-30). The strongest growing fuels are natural gas and oil (from 61% in 1998 to 66% in 2030), while the share of renewables would increase from 6,8% in 1998 to reach 8,1% by 2030. In the same year, the import dependence is expected to reach over 60% (from the 1998 level of 36%), due to a decline in North Sea oil and gas production as well as lower production of solid fuels and nuclear energy. Furthermore, without additional policies, the emissions of CO_2 are projected to exceed their 1990 level by 31% in 2030.

While managing supply dependence requires a diversity of energy sources and supplies, that reduces the external risk factors present, the reduction of greenhouse gas emissions need substantial modification in conversion and utilization of different energy sources and can be achieved by adopting the following solutions:

- efficiency improvement, with reduction of fossil fuel consumption;
- use of low-carbon or carbon-free energy sources (natural gas, renewables, nuclear);
- capture and storage of the CO_2 produced from fossil fuels.

Since fossil fuels will continue to satisfy the largest part of the energy demand in the medium term, efficiency improvement and renewables will not be sufficient by themselves to stabilize the atmospheric CO_2 concentration.

The solution for both the aspects of emission control and security of energy supply could be found in adopting an energy vector such as it:

- is emission free in the final use, while pollutant emissions can be heavily reduced during the production processes;
- can be obtained from a variety of different primary sources (fossil, renewable, nuclear).

Nowadays just electricity and hydrogen exhibit these characteristics.

In particular hydrogen [ESTO, 2003]:

- can be produced from fossil fuels by conversion, with CO_2 capture and storage; this one can be considered the cleanest way to continue using these fuels, that have also in future an important role in our societies;
- can be produced from other sources (renewables, nuclear) without CO_2 emissions;
- can be utilized in different applications (transportation, power production, etc.), not producing any pollutant but water steam.

If the feasibility of CO_2 storage in the long term will be demonstrated, the production from fossil fuels could be considered as a “technological bridge” towards new production processes from renewables and “new nuclear”. Actually, the development in the next decades of technologies for distribution and utilization of hydrogen produced from fossil fuel will be the basis for the introduction of these CO_2-free production technologies in the long term.

Of course introducing hydrogen as a secondary energy carrier presents, beside indubitable pros, several problems in developing technologies for the whole hydrogen cycle (production, distribution, storage, utilization).

Most of the major R, D&D programmes in the world in the energy field are paying attention to the introduction of hydrogen as a fuel and energy carrier as well as to the development of related technologies, like fuel cells.

The important role that hydrogen and fuel cells could play in achieving sustainable energy has been recognized by the European Commission, that created in October 2002 a High Level Group (HGL) with the aim of formulating an integrated EU vision in this field. The HGL prepared a vision report (”Hydrogen and fuel cells – a vision of our future”) (2003) outlining the research, deployment and non-technical actions that would be necessary to move from today’s fossil-based economy to a future sustainable hydrogen-oriented economy with fuel cells as converters.

A preliminary roadmap for this transition is represented in Figure 2.1. The production of hydrogen from fossil fuels, with CO_2 capture and storage, is expected to give an important contribution in the medium term.

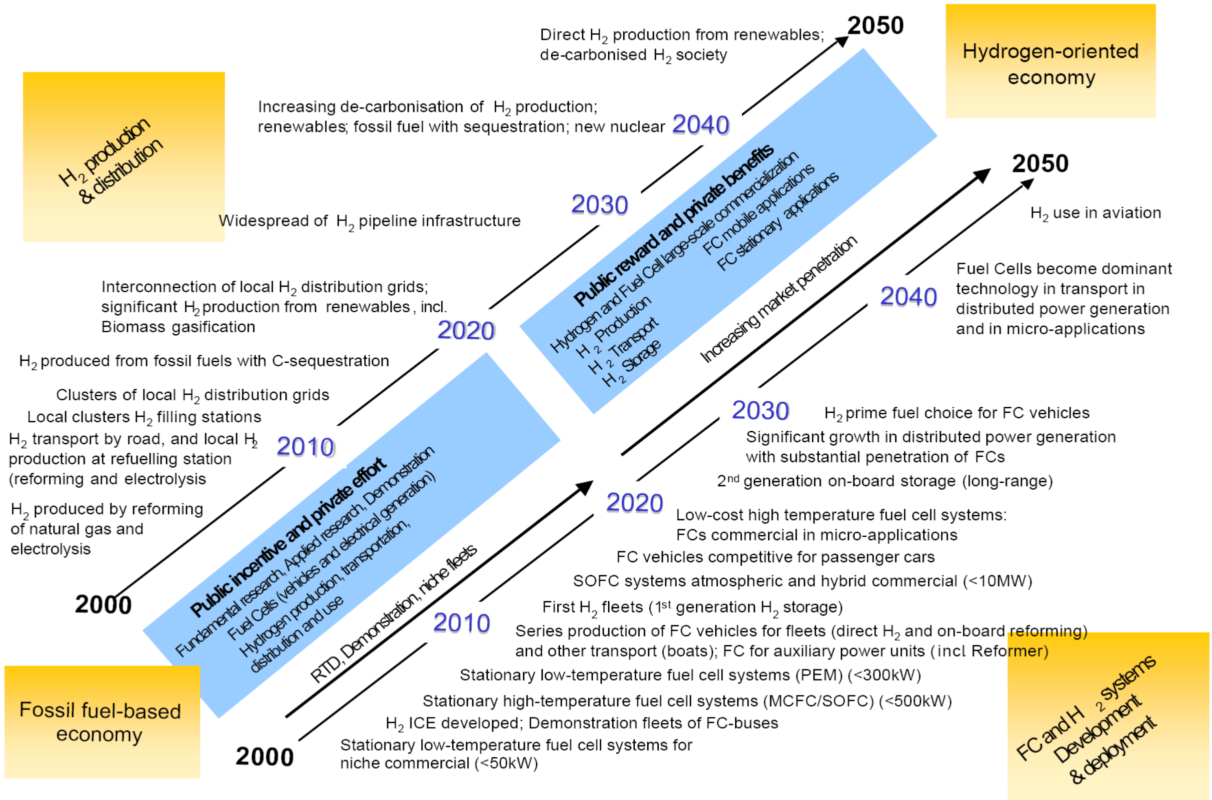


Figure 2.1 – European Hydrogen Vision [EUR 20719 EN]

One of the main recommendation of the HGL report was the establishment of a “European Hydrogen and Fuel Cell Technology Platform”, in order to stimulate and manage the series of initiatives that were identified in the report as being crucial to achieving the transition towards a sustainable energy future.

The European Hydrogen and Fuel Cell Technology Platform was launched at the beginning of 2004, with the main goal of “*facilitating the development and deployment of cost-competitive, world class European hydrogen and fuel cell based energy systems and component technologies for applications in transport, stationary and portable power*”.

The different bodies of the Technology Platform are developing a coherent European research and deployment strategy in the hydrogen and fuel cell sector, including public-private partnership, lighthouse projects, standards and regulations.

In November 2003 the Commission also launched the European Initiative for Growth to accelerate EU economy recovery [COM (2003) 690 final]. The Growth Initiative includes a "Quick Start Programme" of projects of public and private investment in infrastructure, networks and knowledge. The aim is to encourage the creation of public-private partnerships, in cooperation with the European Investment Bank, to leverage finance.

This programme identifies the Hydrogen Economy as one of the key areas for investment in the medium term (2004-2015) and foresees a ten year initiative for hydrogen-related research, production and use, with an indicative total budget of 2,8 billion EUR of public and private funding. This initiative consists of two major projects designed to enable a progressive transition from today's fossil based energy systems to renewable energy sources, based on hydrogen as energy carrier:

- *Hydrogen Communities (HyCom)*. The creation of a limited number of strategically sited stand-alone "hydrogen communities", producing hydrogen from various primary sources, mostly renewables, and using it for heat and electricity production and as fuel for vehicles, is the main goal of this project.
- *Hydrogen and Power Generation (Hypogen)*. A major component will be the first large scale test facility for production of hydrogen and electricity from de-carbonised fossil fuels, with geological storage of CO_2.

The de-carbonisation of fossil fuels via CO_2 capture and storage is a key component of the European strategy in the field of hydrogen and it is seen as a very cost-effective way of producing, in the short to medium term, large quantity of hydrogen needed to accelerate the introduction of this energy vector and its use as a vehicle fuel. The integration of the production plant with a thermal cycle, that uses part of the hydrogen produced for electricity generation, seems to be the most promising solution.

The feasibility of the permanent storage of CO_2 is critical to the success of this approach and represents a high risk associated with the construction of this type of plant and, generally, with the production of hydrogen from fossil fuels in the medium to long term. The capture and storage of CO_2 is, on the other hand, of primary importance for the utilization of fossil fuels in the long term and also in Europe a large R, D&D effort is being carried out in this field, in the context of the development of near-zero-emissions fossil fuel based energy systems.

The carbon capture and storage is a focal point for European research within the 6th Framework Programme, that states explicitly the targets to be met in this field [2002/834/EC]:

> *Capture and sequestration of CO_2, associated with cleaner fossil fuel plants: cost effective capture and sequestration of CO_2 is essential to include the use of fossil fuels in a sustainable energy supply scenario, reducing costs to the order of €30 in the medium term and €20 or less in the longer term per tonne of CO_2 for capture rates above 90%. Research will be focus on: developing holistic approaches to near zero emission fossil fuel based energy conversion systems, low cost CO_2 separation systems, both pre-combustion and post combustion as well as oxyfuel and novel concepts; development of safe, cost efficient and environmentally compatible CO_2 disposal options, in particular geological storage, and exploratory actions for assessing the potential of chemical storage and innovative uses of CO_2 as a resources.*

2.2 Hypogen Objectives

The Hypogen programme could play an important role in the context of the development of an European sustainable energy system in several aspects. First it could demonstrate the technical feasibility and economic viability of producing hydrogen and electricity from fossil fuel with near-zero emissions. Second it could promote the development of hydrogen as energy carrier. With the outreach of the Hypogen programme in mind, the study team tried to formulate the rational behind the Hypogen programme. The specific formulation of these objectives should help to evaluate possible technical and economical solutions for the Hypogen demonstration facility. In detail the set of objectives used for the elaboration of this study comprises the following:

a. Scientific objectives

- develop and prove Hydrogen production technologies with CO_2 capture;
- maintain competitiveness of European research and development as well as of European technology producers;
- stimulate innovation;
- prepare the ground for a hydrogen economy;
- identify barriers and risks.

b. Economic objectives

- install a facility producing hydrogen and electricy;
- demonstrate feasibility of CO_2 capture and storage in a large facility;
- develop a project with "lighthouse" character;
- support security of supply policies, through the utilization of globally better available and long term secure energy carriers and domestic energy carriers;
- stimulate economic growth with R&D and infrastructure investments.

c. Regional objectives

- contribute to infrastructure development;
- contribute to integration of new EU-members.

The European Commission has outlined a series of five phases with an indicative timetable for the realization of the programme:

1.	Pre-feasibility study	2004
2.	Preparation actions and complete feasibility study	2005 - 2007
3.	Demonstration of key technologies	2007 - 2012
4.	Construction and commissioning of major facilities	2008 – 2012
5.	Operation and validation	2012 – 2015.

However, the time frame for the implementation of Hypogen should be flexible enough so that the extensive current and future research should have the possibility to contribute to the development and successful future operation of the plant.

2.3 Similar international programmes

The production of hydrogen and electricity via de-carbonisation of fossil fuels is receiving a growing attention in the frame of international programmes. The most important of them is FutureGen, a 10 years, US$1 billion demonstration project launched by the US government in

February 2003 for the integrated production of electricity and hydrogen from coal, with capture and storage of the CO_2 generated in the process [US DOE, 2004].

2.3.1 FutureGen

The fundamental goal of FutureGen is to overcome the environmental constraints, especially potential climate change impacts of CO_2 emissions, associated with producing electricity and other forms of energy from coal.

The FutureGen plant is planned to operate as a nominal 275 MW (net equivalent output) facility that produces both electricity and hydrogen and sequesters one million metric tons of CO_2 per year. Figure 2.2 provides a simplified flow diagram of the prototype plant.

The plant will employ coal gasification technology to produce a hydrogen-rich synthesis gas, that is

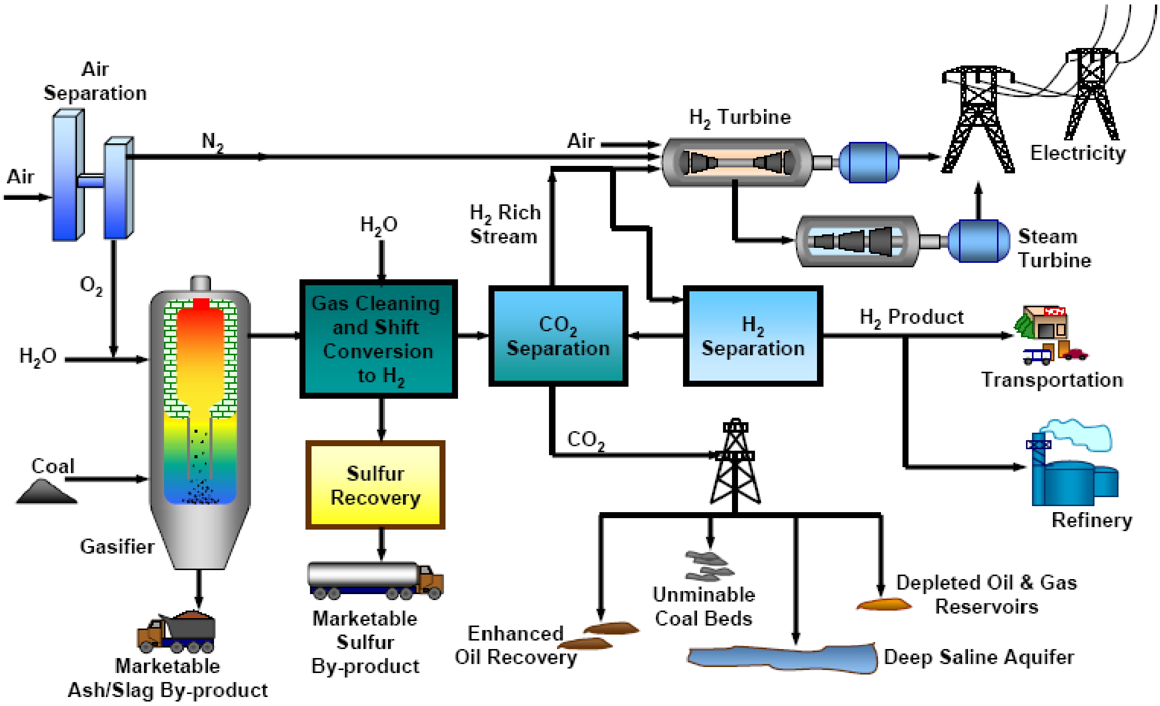


Figure 2.2 - Simplified flow diagram of FutureGen plant (US DOE, 2004)

"shifted" to obtain a concentrated gas stream of hydrogen, steam and CO_2. After separation of these three components, hydrogen can be used to power a gas turbine and/or a fuel cell to generate clean electricity. Some or all of the hydrogen can also be used as a fuel for vehicles or as a feedstock for chemical plants or petroleum refineries. CO_2 from the process will be stored in deep underground geologic formations, located in close proximity to the plant, that will be intensively monitored to verify the permanence of CO_2 storage.

The overall project objectives are to:

- Establish technical feasibility and economic viability of producing electricity and hydrogen from coal with near-zero emissions (including CO_2);
- Verify sustained, integrated operation of a coal conversion system with carbon capture and storage;
- Verify effectiveness, safety, and permanence of carbon storage;
- Establish standardized technologies and protocols for CO_2 measurement, monitoring and verifications; and

- Gain acceptance by the coal and electricity industries, environmental community, international community, and public-at-large for the concept of coal based system with near-zero carbon emissions through the successful operation of FutureGen.

It is not possible to reach these objectives using off-the-shelf commercial technology. Even if an industrial base exists for designing several critical FutureGen components, their efficiencies, environmental performance, reliability and economics must be significantly advanced and tested. Therefore, the prototype plant will serve as a large scale engineering laboratory for testing critical enabling technologies, like advanced gasification, oxygen production, hydrogen production, gas cleanup, hydrogen turbines, fuel cells and fuel cells/turbine hybrids, carbon sequestration, advanced materials, instrumentation, sensors and controls, and by-product utilization.

This approach is different from that used for Hypogen, that will rely mostly on commercial or near commercial technologies.

The project schedule is shown in Figure 2.3.

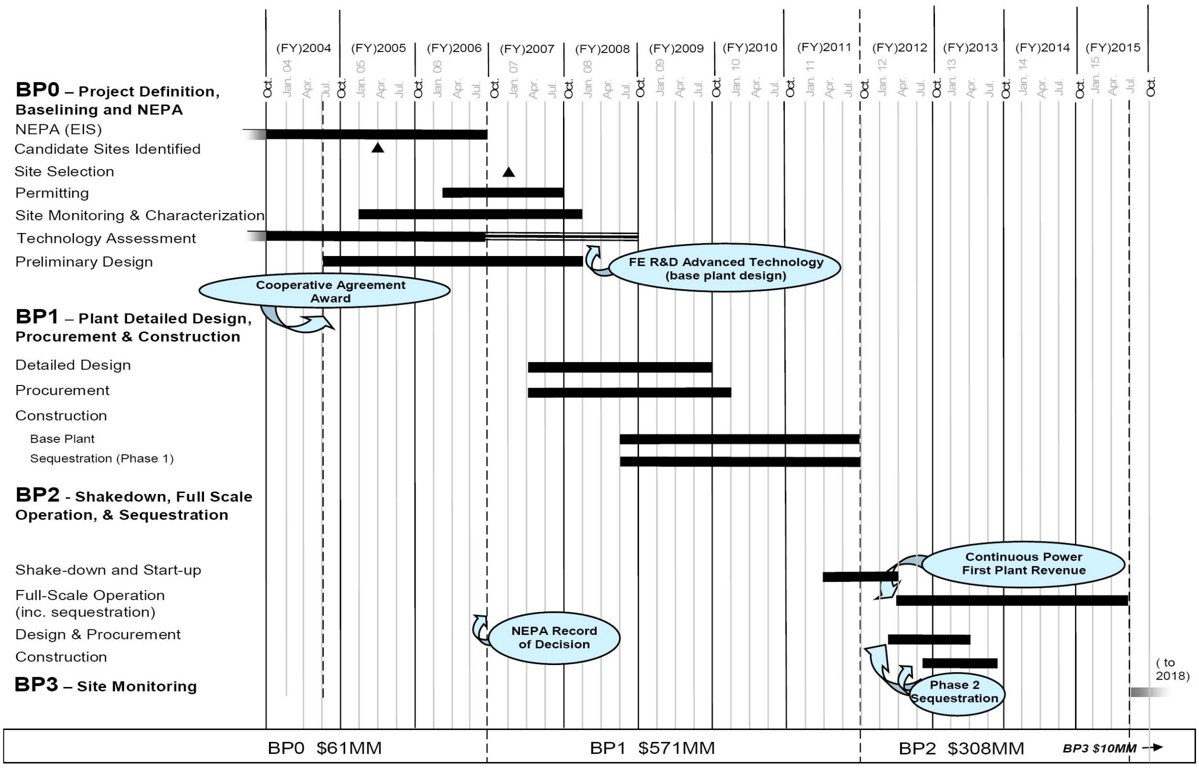


Figure 2.3 - FutureGen Project Schedule (US DOE, 2004)

The estimated total cost of FutureGen project is US$ 950 million. The costs of the different phases are reported in Table 2.1.

The project includes some high-risk activities and requires a large share of public funds. Of the total funding, $250 million (about 26%) is expected to be provided by an industry consortium, $620 million from DOE and $80 million from international partners. This cost-share allocation is based on the following considerations:

- The project's mix of research and demonstration;
- The maturity of the technologies, including the need for integration and testing of unproven technologies at full scale;
- The size of the eventual market, balanced by the relatively long-term horizon for the investment and the risk involved;

- The absence of a clear market or regulatory driver for carbon management technologies for U.S. power generation facilities; and
- The unknown nature of liabilities which may result from this first-of-a-kind integrated project encompassing large scale carbon sequestration.

Table 2.1 – Cost of different phases of FutureGen (US DoE, 2004).

Cost element	Estimated Costs (US$M)
Plant definition, baselining and compliance with the National Environmental Policy Act	81
Plant procurement and construction	480
Shakedown and full-scale operation	188
Sequestration (design and construction)	191
Site monitoring	10
Total	**950**

FutureGen will be structured as a public/private partnership between US DOE, leading companies in the coal and electricity industries, and international entities. The companies should form a Consortium that will enter into a cooperative agreement with DOE to design, construct, and operate the plant. The Consortium may then competitively select the system designers, equipment vendors, and research organizations needed to design, construct and operate the prototype.

To maximize public acceptance for the effectiveness, safety, and permanence of carbon storage, the environmental community, state agencies, ad research organizations will be intimately involved in the project from the onset.

2.3.2 PCDC

The project Pre-combustion Decarbonisation for power generation (PCDC) has been proposed by the IEA Greenhouse gas R&D Programme and the IEA Hydrogen Agreement, with the aim to develop a “standard” engineering design package for a fully integrated hydrogen plant, based on best available technology, with CO_2 capture and producing sufficient hydrogen for a 400 MW combined cycle power generation plant [IEA Hydrogen Agreement, 2003 Annual Report].

The overall plan of the project consists of three phases. The first phase (2000-2005) results in formation of a Joint Industry Project (JIP) and development of a low cost design and estimate with sufficient detail to seek support and funding from consortium members and other institutions (Phase 2). The final phase is the execution of the demonstration, with construction and operation of the plant, with comprehensive performance monitoring. In this phase options to extend the project to foster elements of the hydrogen energy economy will be sought and implemented (for example hydrogen for blending with natural gas or hydrogen for fuel cells).

The overall timing of the PCDC demonstration is closely linked to the development of CO_2 permanent storage, as the project can only be implemented when CO_2 storage has become an accepted practice.

The first stage of the project, started in the year 2000, has been focused on the review of available technologies and on means of reducing the costs to the point at which a commercially viable demonstration could be implemented at a suitable future date. This stage was carried out in collaboration with the CO_2 Capture Project (CCP). In particular, Norsk Hydro, one of the CCP members, completed at the end of 2002 the process review and selection study and concluded that, for the PCDC application, the most suitable process for hydrogen production was the auto-thermal reforming of natural gas. Another study was carried out in 2003 and focused on developing an improved, low cost concept based on modular components; the main result show that only minor cost reduction can be achieved by adopting a standard design but that efficiency would be significantly reduced.

2.3.3 Australia's COAL21 Action Plan

The COAL21 action plan has been launched at the end of 2003 by the Australian government, the coal and electricity industry, and research organizations. The plan is a joint government/industry initiative on greenhouse gas-reduction technologies and identifies a number of emerging technologies that hold the key to reducing or even eliminating emissions from coal. In particular, the capture of CO_2 emissions from power stations and permanent storage in underground geological structures is identified as the pathway to achieving near zero emissions systems.

In this frame the coal's role as a primary sources of hydrogen to power the hydrogen-based economy of the future will be explored [Greenhouse Issues, 2004].

2.3.4 Canadian Clean Coal Technology Roadmap

In 2001 the Climate Change Technology and Innovation Program (CCTIP) has recognized the importance in developing a Clean Coal Technology strategy for Canada and has selected the Technology Roadmap process as the instrument to be used in the initial planning stage.

The Clean Coal Technology Roadmap provides an outlook to the future and identifies the technology pathway needed to allow coal to be used as a competitive environmentally clean energy resource for the production of electricity, both in the mid and in the long term. In this frame, the IGCC technologies for power, hydrogen and chemical production are one of the energy system pathways identified.

The Roadmap will aim to build on the efforts of the Canadian Clean Power Coalition (CCPC), an association of Canadian coal and coal-fired electricity producers, set up in mid 2001 with the aim to secure a future for coal electricity generation. CCPC is looking at the demonstration of new coal technologies. The first demonstration plant is planned to be in operation by 2010 and will be designed to remove CO_2 and all other environmental emissions of concern.[1]

2.4 Relevant European Projects

Several projects have been or are being carried out in Europe, which are relevant to Hypogen. Few of them explore, as Hypogen, the co-production of power and hydrogen, via de-carbonization of fossil fuel, while the major part concern the development or demonstration of technologies and systems of paramount importance for Hypogen, like for example those related to the Integrated Coal Gasification Combined Cycle plants and to CO_2 capture and storage. An overview of the most important are reported in the following.

2.4.1 Co-production of hydrogen and electricity

2.4.1.1 Hydrokraft project

The possible utilization of pre-combustion de-carbonization of natural gas for power generation has been considered by Norsk Hydro in the frame of the Hydrokraft project, initiated in 1998 to

[1] Information about Canadian Clean Coal Technology Roadmap available at: http://www.nrcan.gc.ca/es/etb/cetc/combustion/cctrm/htmldocs/overview_e.html

evaluate an integrated reformer combined cycle (IRCC) for a proposed 1200 MW installation on the west coast of Norway. The proposed plant comprised an auto-thermal reformer with CO-shift and an absorption process for CO_2 separation (with CO_2 to be used in an oil field for enhanced oil recovery - EOR). The power section includes a triple-train combined cycle unit with both gas turbine and heat recovery steam generator integrated with the reforming section.

Combustion test carried out in 1999 by Norsk Hydro concluded that commercially available gas turbines can successfully be fired with the hydrogen-rich (40% to 80%) fuel gas, but the plant efficiency was around 50%, lower than that achieved with natural gas (56%). Through this process, CO_2 emissions can be reduced by 90% and the cost of CO_2 capture was estimated at US$36 per tonne. The plant was considered too risky for its complexity and economic cost and because its development was linked to an oil field, due to come on-line in 2003 [IEA, 2002].

2.4.1.2 Klimatek

In the frame of Klimatek, the Norwegian programme for the research, development and demonstration of greenhouse gas control technologies, a project is being carried out with the primary objective of developing and testing a concept for co-production of electric power and hydrogen from natural gas with integrated CO_2 capture and high overall efficiency. The project will be completed in 2005, with a cost of about 2,97 million Euro. The participants are the Christian Michelsen Research Group (CMR) and the Institute for Energy Technology.[2]

2.4.1.3 Drym Power Station

Valleys Energy Ltd (UK) is proposing the construction of a 460 MW IGCC power station, that will not only generate electricity but could also be used to supply hydrogen and is being specifically designed so that, in the future, CO_2 could be captured for long-term storage. The plant, located in Wales, will use locally-produced coal, blended with some oil refinery products, and will cost about UK£375 million. Subject to planning approvals, the construction of the plant will begin in 2004 and the production of electricity in 2007 (Greenhouse Issues, 2003).

A similar project, proposed by Coalpower Ltd, for a 430 MW power station close to Hartfield Colliery in Yorkshire has been stopped in 2004 for funding difficulties.

2.4.1.4 Enel's Hydrogen Project

Enel, the main Italian electric utility, is investing in hydrogen production, utilization and storage with the ambitious target of providing a competitive hydrogen infrastructure in the next years. The hydrogen production will be integrated with the already existing power plant in order to reduce production costs and to create, on a small scale, a whole "hydrogen system" in the area of the plant.

The first step of this programme will be the construction of a 12 MWe plant, producing hydrogen from coal and using it for electricity and heat generation. This plant, fully integrated with an existing Enel coal plant (Fusina power plant), is located in the context of the "Hydrogen Park" based in the industrial area of Marghera (Venice).

The first phase of the project includes the development, realization and operation by 2007 of a co-generative plant based on a 12 MW turbogas with steam injection, feed by the hydrogen already available from the Marghera chemical plant. The research programme will face and solve the critical aspects rising from the use of hydrogen in a conventional commercially available gas turbine, with the aim of reaching a near-zero emission cycle (1 digit NOx).

Meanwhile, Enel will built a coal gasification section. The coal required for the gasification process will be taken from the existing power plant, utilising the same logistic chain. CO_2 will be separated

[2] Information about Klimatek available at: http://www.co2sequestration.info/

and sent through a piping to a near DOW chemical plant, where it is re-used to produce polycarbonates. Once the gasification part will be in operation, the co-generative cycle will be fully fed by the hydrogen produced from coal.

The ability to produce hydrogen locally, exploiting synergies with existing facilities, is Enel's key strategy to effectively speed up hydrogen's introduction in the energy scenario [Cassì L., 2004).

2.4.1.5 Co-production of hydrogen and electricity from refinery residues

In Europe several plants producing hydrogen and electricity from refinery residues are operating or are planned for the near term (see next chapter, 3.4).

2.4.2 Clean power plant technology

Hypogen can benefit by the experience in technology development gained by several European projects in the field of clean power production. Some examples of them are in the following.

2.4.2.1 Puertollano IGCC plant (Spain)

This project was launched in 1992 by ELCOGAS, a consortium of eight European utilities and three technology suppliers, to demonstrate the commercial feasibility of the Integrated Gasification with Combined Cycle (IGCC) technology. The Puertollano plant is a 300 MW (net) facility, designed to use a 50/50 mixture of high ash local coal and petroleum coke from a nearby refinery. The high integration of the plant enables it to operate at high efficiency (42%), but has reduced its operating performance, with a limited availability in the first years. The plant has been operating in 2001 and 2002 more than 5,100 hours/year as IGCC and more than 7.000 hours/year as total operating time (syngas plus natural gas), demonstrating its competitiveness in the Spanish liberalised electricity market [Hanneman et al., 2003].

The Puertollano project is of great interest for Hypogen not only for the technologies involved (see chapter 3), but also for other aspects concerning the financial engineering and the project structure.

As said before, the plant is owned and operated by a consortium of utilities (eight, from five different European countries: Spain, Portugal France, Italy and UK) and technology suppliers (three, from Spain and Germany). Moreover, the US$ 894 million power plant used a financing scheme that involves, besides the plant owners and the income for energy sales,

- The European Commission (THERMIE Programme),
- A team of 35 different banks from eight different countries.

Tab. 2.2 – Sources and uses of funds for Puertollano plant (Trevino et al., 1998)

Sources of funds	US$	***Uses of funds***	US$
Owners	214	Investments	711
Grants	53	Fuel stock + VAT	79
Main loan debts	499	Financing expenses paid	104
Income from energy sales	128		
Total	**894**	**Total**	**894**

The experience of the Shareholders and of the Suppliers, but especially the support of the different authorities (Spanish Government and European Commission) were deemed fundamental by the bank's team to achieve an agreement [Trevino et al., 1998].

2.4.2.2 Buggenum IGCC plant (The Netherlands)

The plant, commissioned in 1994 by Demkolec BV and today owned by NUON, is a 253 MW (net) IGCC designed to utilize a number of different imported coals. Like in Puertollano plant, its high integration increases efficiency of the system, but makes it more complex. After encountering some operating problems mainly related to turbines in its initial years, design changes were made in 1997 that significantly improved plant performance (availability over 95% in the first part of 2004).

The plant served as an IGCC demonstration plant in its first phase and had been used to test different operating conditions and various feedstock. After the change of ownership to NUON, the plant management decided to operate the plant for commercial purpose and conducted programmes aiming at achieving stable operation.

According to Hanneman et al. (2002), among the next steps for further economic improvement of the plant, the peak shaving operation, with gasifier and air separation unit (ASU) operating at less than 100%, is considered. To this end, a feasibility study to separate Combined Cycle from gasifier and ASU operation is planned, together with the production of alternative fuels.

2.4.2.3 Gas turbines for syngas application

The availability of high efficiency gas turbines able to operate with hydrogen rich gas is a key issue for power generation system utilizing de-carbonised fossil fuels. The main changes have to be made in the combustion system, to accommodate high gas flowrates, lower heating values and other characteristics of alternative fuels. The development of advanced burner technology for these turbines is being carried out in the frame of an European project (HEGSA: High Efficient Gas Turbine for Syngas Application"), that began in 2003 and will finish next year [Hanneman et al., 2003]. The project, led by Siemens, involves Ansaldo Energia, utilities (NUON, ENEL Produzione) and research institutes. The main objectives of the project are:

- Increasing theoretical and technological knowledge of syngas combustion,
- Improving the flexibility of current gas turbine syngas combustion systems,
- Developing and advanced combustion system for annular burner technology operating at higher pressure and temperature using low-BTU syngases.

2.4.3 CO_2 capture and storage

The level of funding for carbon sequestration programmes has been increased continuously by the European Commission in recent years. In the Fourth Framework Programme (1994-1998) the first phase of the SACS project (the demonstration of Saline Aquifer CO_2 Storage in the Sleipner Field) was funded, while in the 5th Framework Programme (1998-2002), the European Commission spent more than €33 million in activities related with carbon capture and storage. The projects already started in the 6th Framework Programme have a total cost of about €65 million, with funding of European Commission of €35 million [Tzimas and Peteves, 2003]. Among the most important projects that have received funding from the European Commission, the most recent are:

2.4.3.1 CO2STORE

This large-scale project is a follow-on to the current Sleipner project, which involves injection of about one million metric tons of CO_2 into an off-shore saline formation beneath the North Sea. The project started in 2003 and has two main goals: i) to extend the work on Sleipner to investigate the long-term fate of the injected CO_2 and evaluate other monitoring techniques that could be more cost effective than seismic surveys, (ii) apply the knowledge gained in SACS 1&2 projects to develop site-specific plans for CO_2 storage operations elsewhere in Europe, both on and off-shore.

2.4.3.2 NASCENT/Natural Analogues to the Storage of CO2 in the Geological Environment

NASCENT addresses the key issues of geological carbon storage by using natural CO_2 occurrences as analogues for geological repositories of anthropogenic CO_2. The issues studied include the long-term safety and stability of storage underground and the potential environmental effects of leakage from an underground reservoir. Among the contractors are geological research organizations from UK, France, Germany, the Netherlands, Greece, Hungary and universities. The project started in 2001, with duration of 3 years. The total budget is €3.29 million, €1.86 million being funded by the Commission.

2.4.3.3 GESTCO/The European Potential for Geological storage of CO_2 from Fossil Fuel Combustion

The principal objective of GESTCO is to identify the CO_2 geological storage capacity in Europe. To this end, the study investigates the storage potential of four main storage types in selected areas: i. Onshore/offshore saline aquifers with or without lateral seal; ii. Low enthalpy geothermal reservoirs; iii. Deep methane-bearing coal beds, and abandoned coal and salt mines; iv. Exhausted or near exhausted hydrocarbon structures. The project started in 2000 with duration of 3 years. Participants include national geologic surveys and research organizations. The project budget is €3.8 million, 50% is funded by the European Commission.

2.4.3.4 RECOPOL/Reduction of CO_2 Emission by Means of CO_2 Storage in Coal Seams in the Silesian Coal Basin of Poland

In this project the feasibility of GHG emission reduction by CO_2 storage in subsurface coal seams is studied. Locally produced CO_2 or flue gas from a power plant will be injected in the coal at a selected test site in the Silesian Coal Basin (Poland) with a rate of 20 tonnes per day, while methane (CH_4) will be produced simultaneously. This research involves laboratory work, model simulations, and investigation of time-lapse monitoring. Existing wells at the test site and a newly drilled well will be used for the test. The project started in 2001 and will be concluded in 2004. The total budget is €3.44 million, half of it will be funded by the European Commission.

2.4.3.5 CO2NET/European Thematic Network

CO2NET is the European Network of researchers, developers and users of CO_2 technology, facilitating co-operation between these organisations and the European projects on CO2 geological storage, CO_2 capture and zero emissions technologies. The aim of the network is to: facilitate research collaboration and map European centres of excellence; assess and define R&D strategy; provide information to assist policy making at European and national level; develop training materials and educational activities/material; increase public awareness towards acceptance; assess best practice; lay foundations for benchmarking and standardization; facilitate exploitation and dissemination of CO_2 projects and results; establish real-time online communication facility; and, develop an interactive relational database for collation of all information and network outputs.

2.4.3.6 WEYBURN/The Weyburn CO2 Monitoring Project

This project will enhance the knowledge and understanding of the underground sequestration of CO_2, especially where associated with EOR, and develop and enhance monitoring techniques to ensure safe and stable underground storage. It is anticipated that approximately 20 million tonnes of anthropogenic CO_2 will be permanently sequestered underground during the project. The project takes place at the Weyburn oil field (Saskatchewan, Canada) being an integral part of a long-term IEA-facilitated project with a total budget of Can$1.5 billion. The European Commission provides €1.19 million to fund the project. Injection of anthropogenic CO_2, generated during coal gasification, has started at the end of year 2000.

2.4.3.7 CASTOR

This is a pilot-scale project that will attempt to validate, from process, economic, legal, and public acceptance perspectives, post-combustion capture and storage of CO_2. The project will separate CO_2 from a post-combustion gas stream for sequestration and will perform risk assessment studies for four new European storage sites: Casablanca (Mediterranean Sea – depleted oil field), Snohvit (Norway – saline formation), Kindbach (Austria – depleted gas field) and K12b (Netherlands – depleted gas field), three of which will commence injection during lifetime of the project. Overall, about €16 million has been committed to the project, with about €8 million coming from European Commission. The project began in February 2004 and will run for about five years, with operation of a pilot plant starting about 2006. The goal of the project is to achieve a major cost reduction in post-combustion per-ton CO_2 capture cost.

2.4.3.8 CO2SINK

This project will test and evaluate CO_2 capture and storage at an existing natural gas storage facility near Berlin, Germany, and in a deeper land-based saline formation. The goal of the projects is to advance understanding of the science and practical processes involved in underground storage of CO_2 and to provide real case experience for use in development of future regulatory framework for geologic storage. The project will start in 2004 and run for about five years. The total budget is around €15 million, with about €9 million coming from European Commission.

2.4.3.9 ENCAP

The main goal of ENCAP project is the development and demonstration of pre-combustion capture technologies. The technologies employed shall be able to reach a total CO_2 capture cost of around 20 €/ton CO_2 avoided, while achieving capture yields well in excess of 90%. The project started in 2004 and will run for about five years. Two phases are planned: 2003-2005 and 2005-2007, with decision on pilot testing between phases. The total budget of the project amounts to about €30 million, with a contribution of European Commission of €9.8 million. Participants are 28 European companies and research organizations.

2.5 Summary and conclusions for Hypogen

- The de-carbonisation of fossil fuels via CO_2 capture and storage is a key element of the European strategy for the development of a sustainable energy systems in the long term. Hypogen could play an important role in this context, demonstrating the technical feasibility and economic viability of producing hydrogen and electricity from fossil fuel with near-zero emissions and promoting the development of hydrogen as energy carrier.
- The production of hydrogen and/or electricity via de-carbonisation of fossil fuels is receiving a growing attention in the frame of international programmes. The most important of them is FutureGen, a 10 years, US$1 billion demonstration project launched by the US government in February 2003 for the integrated production of electricity and hydrogen from coal, with capture and storage of the CO_2 generated in the process. FutureGen will use advanced technologies and will serve as a large scale laboratory for testing them.
- Several projects have been or are being carried out in Europe, which are relevant to Hypogen. Few of them explore, as Hypogen, the co-production of power and hydrogen, via de-carbonization of fossil fuel, while the major part concern the development or demonstration of technologies and systems of paramount importance for Hypogen, like for example those related to the Integrated Coal Gasification Combined Cycle plants and to CO_2 capture and storage. The experience and technologies developed in the frame of these projects, and the possible synergies with them, will give an essential contribution to the success of Hypogen.

3. PRE-ASSESSMENT OF TECHNOLOGY OPTIONS

3.1 Technology options

A Hypogen facility produces hydrogen and electricity from fossil fuels. The fossil fuel to be used in such a plant could be natural gas, heavy oils, or coal. To have a power and hydrogen production from fossil fuels with near-zero CO_2 emissions, the Hypogen will be equipped with carbon capture technology and storage. To built a Hypogen facility several technology options exist for the different parts of the plant:

- hydrogen production from different fuels (reforming, partial oxidation, gasification),
- gas clean up,
- thermal cycles for power production,
- CO_2 capture,
- CO_2 transport and storage,

as well as for auxiliary systems (for instance O_2 production, if needed).

An overview of the state of the art of the most promising technologies and systems, that could lead to the realization of a Hypogen facility in the period 2008-2010, is reported in this chapter.

3.2 Hydrogen production from hydrocarbons

3.2.1 Processes

The production of hydrogen from fossil fuels takes place in industrial units in small and large scale from feedstock like natural gas, LPG, liquid hydrocarbons, and coal. The optimum choice of technology for hydrogen production depends on the type of feedstock and the scale of operation. The primary means of hydrogen production today is catalytic reforming of natural gas, which is a mature technology. About 95% of today's merchant hydrogen is produced by centralised reforming of natural gas [HyNet, 2004]. In the following the main currently used technologies for production of hydrogen from hydrocarbon feeds will be described and the future perspectives are discussed briefly [Rostrup-Nielsen, J.R. and Rostrup-Nielsen , T., 2002; Sehested et al., 2004]. Table 3.1 lists the key reactions for making hydrogen.

Table 3.1. Reactions for making hydrogen from hydrocarbons

Process	$-\Delta H^o_{298}$ kJ/mol
***Steam Reforming*:**	
1. $CH_4 + H_2O = CO + 3H_2$	-206
2. $C_nH_m + nH_2O = nCO + (n + \frac{m}{2}) H_2$	-1175 (*)
3. $CO + H_2O = CO_2 + H_2$	41
CO_2 Reforming:	
4. $CH_4 + CO_2 = 2CO + 2H_2$	-247
***Autothermal Reforming (ATR)*:**	
5. $CH_4 + 1\frac{1}{2}O_2 = CO + 2H_2O$	520
6. $CH_4 + H_2O = CO + 3H_2$	-206
7. $CO + H_2O = CO_2 + H_2$	41
Catalytic Partial Oxidation (CPO):	
8. $CH_4 + \frac{1}{2}O_2 = CO + 2H_2$	38

(*) for *n*-C_7H_{16}

Steam reforming of hydrocarbons is the dominating process for production of hydrogen today [Rostrup-Nielsen et al., 2002]. The major part of the hydrogen production is for use in refineries. Natural gas is the typical feedstock, but a number of liquid hydrocarbon streams including naphtha/petrol are also used. A block diagram of the main sections in a hydrogen plant is shown in Figure 3.1. The first step is purification of the hydrocarbon feed. Natural gas and naphtha contain traces of sulphur, which will result in fast deactivation of the reforming catalyst if allowed into the reforming unit. Purification of the feed is normally done using a hydrogen desulphurization (HDS) catalyst, which converts all sulphur-containing compounds to H_2S. H_2S is absorbed in a ZnO bed with ZnS as the product. A copper-based purification catalyst may have to be installed after the ZnO reactor for final purification.

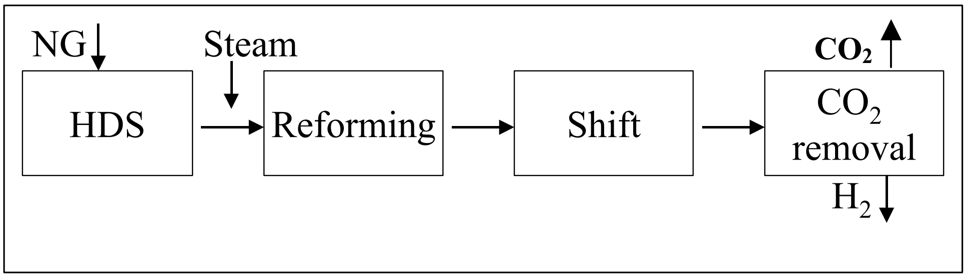


Figure 3.1. Block diagram for a typical hydrogen plant. Natural gas (NG) and steam are supplied as feed and hydrogen is the final product

After purification, steam is added to the feed and the gas is converted to synthesis gas by steam reforming. The steam reforming reactions are strongly endothermic and lead to an expansion of the gas. Pressures of 20-40 bars are typically applied in industrial reforming units. This pressure is dictated by the necessity of high throughput and low pressure drop on one side and the reduced conversion and increasing cost of using high pressures on the other side.

Modern steam-reforming units consist of a primary reformer with an upstream pre-reformer. A typical layout is shown in Figure 3.2. The adiabatic pre-reformer converts the higher hydrocarbons into a mixture of carbon oxides, methane, steam and hydrogen according to reactions 1-2 in Table

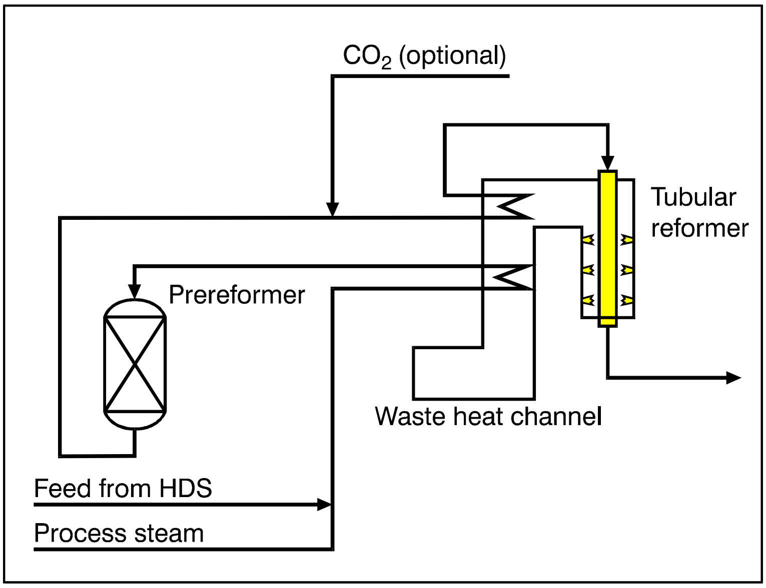


Figure 3.2 – Flow diagram of a typical reforming unit

3.1. The primary reformer consists of a large number of high alloy steel tubes filled with catalyst and placed in a furnace. The diameter of a tube is typically 10-15 cm and the length is from 10 to 13

m. The inlet temperature is between 450-650°C while the outlet temperature is 800-950°C. A nickel catalyst supported on a ceramic carrier is preferred industrially. Precious metals are more active and have higher resistance towards carbon formation but are too expensive for industrial hydrogen plants.

The product from the reformer contains CO, CO_2, and a minor amount of unreacted methane, which have to be removed to obtain pure hydrogen. The water gas shift reaction (3, in Table 3.1) is used to convert CO to CO_2 and produce H_2. Water gas shift may be carried out in one or two adiabatic reactors using a Cu based catalyst. After the shift section, the remaining CO, methane and CO_2 can be removed by "Pressure Swing Adsorption" (PSA) or chemical wash if required in the downstream use of hydrogen. Removal of CO can be completed by methanation (reverse of reaction 1 in Table 3.1).

Partial oxidation represents an alternative to steam reforming. It can be carried out in three ways. The non-catalytic partial oxidation (POX) requires high temperature to ensure complete conversion of methane and to reduce soot formation. This method is mostly used for heavy feeds. Some soot is formed and is removed in a separate scrubber system downstream of the partial oxidation reactor [Marion et al., 1969]. The thermal processes typically results in a product gas with H_2/CO ratio in the range of 1.7-1.8. Hence, CO removal is necessary for production of pure hydrogen.

The autothermal reforming (ATR), process [Ernst et al., 2000], is a hybrid of partial oxidation and steam reforming using a burner and a fixed catalyst bed for equilibration of the gas. However, autothermal reforming with oxygen will mainly be interesting in connection with hydrogen production in very large plants due to the prize of establishing an oxygen plant. Autothermal reforming is the preferred technology for large-scale production synthesis gas for production of methanol or synthetic diesel by the Fisher-Tropsch synthesis.

In catalytic partial oxidation (CPO), the reactants are premixed, and all the chemical conversions take place in a catalytic reactor without a burner [Bodke et al., 1998; Basini et al., 2001]. The direct CPO reaction (8 in Table 3.1) provides a H_2/CO molar ratio of 2 and has a low heat of reaction (38 kJ/mol). In practice, the reaction is accompanied by the reforming and water gas shift reactions, and, at high conversions, the product gas will be close to thermodynamic equilibrium [Rostrup-Nielsen et al., 2002]. CO removal is also necessary for production of pure hydrogen in this case.

As the reforming technology is well developed the needs for further R&D relate especially to catalysts, hydrogen purification and gas separation membranes.

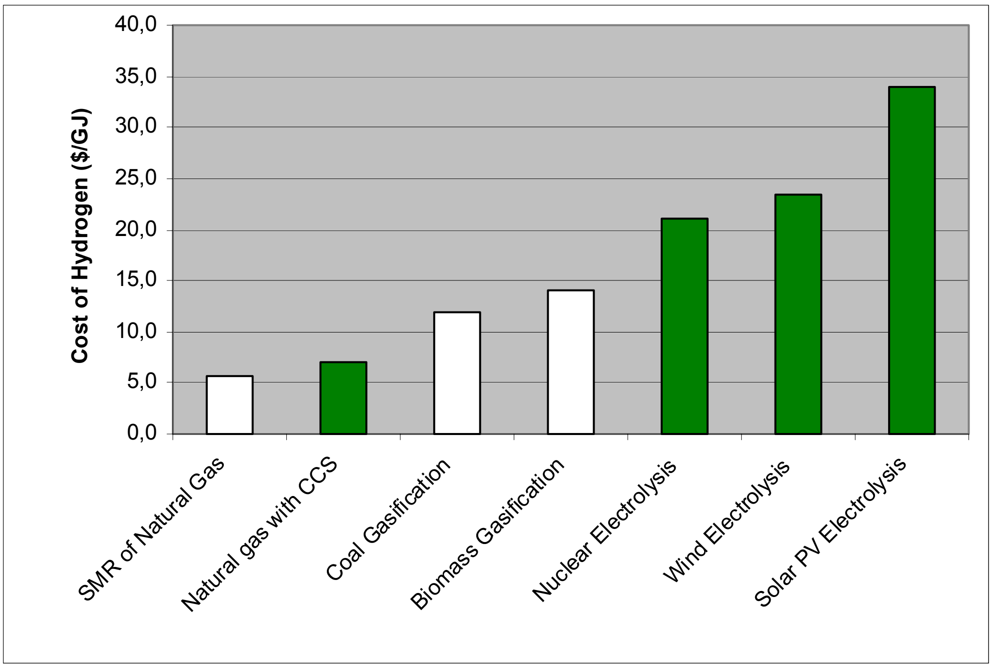
3.2.2 Hydrogen cost

Several studies [JRC, 2004; NRC, 2004; Simbeck et al., 2002; Gray et al., 2002] points to reforming of natural gas in a centralized plant as the cheapest way to produce and distribute hydrogen for the time being, even including the cost of CO_2 sequestration.

Further to this, Bill Senior of BP responded to the question from the Hypogen Pre-feasibility Study Kick-Off Meeting in the following way:

> *Producing hydrogen by steam reforming of natural gas (plus naphtha and LPG) is the dominant source of hydrogen today in refining and other industrial applications. It is generally the lowest cost current option.*
>
> *There are a range of studies on the cost of hydrogen from natural gas with and without CO_2 Capture and Storage, including Hynet, various IEA reports and the US National Academies hydrogen report. All the current economic assessments show that thermo-chemical routes to produce hydrogen from gas or coal are substantially lower cost than electrolysis.*

Our view is that the lowest cost route to manufacture hydrogen in Europe is by steam methane reforming (SMR) of natural gas. Various estimates indicate hydrogen from SMR will cost in the region of \$5.6/GJ. Capturing and storing the emitted CO_2 is estimated to add 20-25% to the cost bringing the hydrogen cost to approximately \$7/GJ. This cost is well below the estimated cost of \$21/GJ the lowest cost carbon free electrolysis route using nuclear electricity. The cost from coal gasification with or without capture is also approximately twice the cost from natural gas. Note that the drivers are the fuel cost, energy penalty and technology cost.



Carbon Free Not Carbon Free *Source: IEA GHG, DTI EIBU, UNU*

Assumptions:
\$3/GJ natural gas (\$2.84/mmbtu); \$1.35/GJ for coal; nuclear electricity supplied at 4.9c/kWh; wind electricity supplied at 4.2c/kWh; solar PV electricity at 5.7c/kWh

Figure 3.3 - Cost of hydrogen manufactured using different technologies (BP)

Steam methane reforming of natural gas combined with CO_2 capture and storage is therefore the lowest cost production route for carbon free hydrogen currently available.
Advanced Pre-Combustion CO_2 Capture technologies will reduce the technology/energy costs. There are several promising technologies requiring further development such as hydrogen separation membranes, Sorption Enhanced WGS and integrated systems like the Hydro Membrane reformer.

3.3. Hydrogen production from coal

3.3.1. Coal gasification.

Coal gasification offers one of the most versatile and cleanest ways to convert the energy content of coal into electricity, hydrogen, and other energy forms. Various coal gasification electric power plants are now commercially operating in different countries. The capability to produce electricity, hydrogen, chemicals, or their combinations while virtually eliminating both air pollutants and potentially greenhouse gas emissions makes coal gasification one of the most promising technologies for the energy and hydrogen production plants.

Gasification is defined as the reaction of solid fuels with air, oxygen, steam, hydrogen, carbon dioxide or a mixture of these gases at a temperature exceeding 700°C to yield a gaseous product suitable for use either as a source of energy or as a raw material for the synthesis of chemicals, liquid or other gaseous fuels.

Rather than burning coal directly, gasification breaks down coal into its basic chemical constituents. In modern gasifiers, coal is typically exposed to hot steam and carefully controlled amounts of air or oxygen under high temperatures and pressures. Under these conditions, carbon molecules break apart, setting into motion chemical reactions that typically produce a mixture of carbon monoxide, hydrogen and other gaseous compounds.

3.3.1.1 Fundamental stages

A large number of chemical reactions are produced in series and in parallel: combustion with oxygen (partial combustion), gasification with carbon dioxide (Boudouard reaction), water gas reaction, hydrogasification, water gas shift, methanation reaction. In a easier way it is possible to distinguish three fundamental stages:

1) Pyrolysis: following the drying and heating processes in which volatile substances are given off, pyrolysis or the thermal decomposition of the coal occurs. During this process, char and a gaseous fraction, rich in hydrogen, are produced.

2) Combustion: the gases produced are burnt, using most of the oxygen fed to the gasifier. The reactions are exothermic, and release the necessary heat to produce the gasification reactions. In turn, the carbon residue partially reacts with the oxygen that has not been used, until it is completely reacted.

3) Gasification: once all the oxygen has been used up, the reactions between the combustion gases (CO_2 and H_2O) and the char take place, generating CO and H_2. The final composition of the synthesis gas depends on pressure and temperature conditions, which in turn depends on the different equilibriums established according to the fuel and the gasifying agents (air or oxygen, steam) used. High temperatures reduces H_2O and CO_2 concentrations, while those of CO and H_2 are increased.

3.3.1.2 Coal classification

Coal ranking is essentially based on few parameters: the fixed carbon percentage, the volatile matters percentage and the heating value. The table 3.2 shows the coal rank proposed by ASTM [DOE 1998].

The cost of different types of coal is reported in Fig. 3.4. [DOE, 2003].

As the low heating value of lignite and antracite are, respectively, 8.5 and 29.2 MJ/kg, the cost of each unit of energy is lower for lignite than for antracite.

Table 3.2 -Coal classification [DOE 1998

Coal Rank	**Fixed carbon limits in percentage** ***(Dry mineral-matter free basis)***		**Volatile matter limits in percentage** ***(Dry mineral-matter free basis)***		**Higher heating value limits** (MJ/kg on moist, mineral- matter free basis		**Agglomerating character**
	Equal or greater than	***Less than***	***Equal or greate r than***	Less than	Equal or greater than	Less than	
Rank							
Anthracitic	86	98(+)	2(-)	14	-	-	Non-agglomerating
Bituminous	69	86	14	31	-	-	Agglomeranting
Bituminous	-	69	31	-	32.56	-	Commonly agglomeranting
Bituminous	-	-	-	-	26.75	32.56	Commonly agglomeranting
Bituminous	-	-	-	-	24.42	26.75	Agglomerating
Subbituminous	-	-	-	-	24.42	26.75	Non agglomerating
Subbituminous	-	-	-	-	19.30	24.42	Non-agglomerating
Lignitic	-	-	-	-	-	19.30	Non-agglomerating

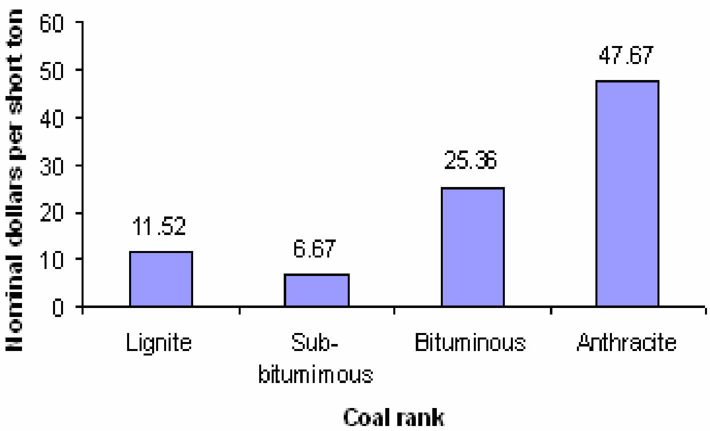


Figure 3.4 – Cost by type, 2002
Source: *Energy Information Administration Review 2003 available from:* http://www.eia.doe.gov/emeu/aer/pdf/pages/sec7.pdf;

3.3.1.3 Gasification Processes

Different gasification technologies are present on the market. The most common way of classifying them is by flow regime, i.e. the way in which the fuel and oxidant flow through. Three main groups can be individuated: entrained flow, fluidised bed and moving bed.

Entrained Flow Gasifiers - Pulverized coal flows co-currently with the oxidiser (typically O_2 and steam). The key characteristics of entrained flow gasifiers are their very high and uniform temperatures (usually more than 1000 up to 1400°C) and the very short residence time of the fuel within the gasifier. Solids fed into the gasifier must be ground very fine and of homogeneous quality, making the gasifier technology not suitable for biomass or waste. The ash is removed as a molten slag. Entrained flow gasifier technology includes the Texaco gasifier, Shell, Prenflo and

Egas/Destec gasifier technologies. Of both the Texaco gasifier and the Shell gasifier more than 100 units are in operation worldwide.

Fluidised Bed Gasifiers – Pulverized coal is suspended in an upwardly flowing gas stream (the oxidant is generally air rather than O_2). To avoid agglutination and performance losses, the temperature is kept below the ash melting point. The use of air as the oxidant keeps the temperature below 1000°C. Fluidised bed gasification technologies includes the High Temperature Winkler reactor (HTW) and the technology developed by British Coal Corporation and now marketed by Mitsui Babcock Energy Ltd (MBEL). There are relatively few large fluidised bed gasifiers in operation. Fluidised bed gasifiers are also suitable for biomass but not for liquid feeds.

Moving Bed Gasifiers – The syngas produced moves upward through a bed of solid feedstock, which gradually moves downwards as the feed at the bottom of the bed is consumed. A moving bed gasifiers is classified as counter-current flow. The temperature profile varies , from 1000°C or more at the bottom down to 500°C at the top. This kind of gasifiers can accept coal as well as other fuels such as biomass and waste. There are two main moving bed gasifier technologies: 1) the Lurgi dry-ash gasifier, extensively used for production of town gas and chemicals from coal. 2) British Gas Corporation gasifier (now BG plc) currently installed in plants for gasifying solid wastes and co-gasifying coal and waste.

Table 3.3 – Gasification processes

	Entrained bed	Fluidised bed	Moving bed
Pressure [bar]	20-85	20-30	20-25
Temperature [°C]	1400-1600	800-1000	370-600
Moderator	steam-water	steam	steam
Amount of moderator	Low	medium	high
Oxidant	Oxygen	oxygen-air	oxygen/air
Amount of oxidant	High	medium	low
Fuel mesh size [mm]	0.05-0.1	3-4	5-50
Fuel feeding type	dry/wet	dry	dry
Syngas LHV	High	medium-high	high
Syngas type	mostly H2 and CO	low CH4 %	high CH4 %
Slag	Molten	dry-caking	dry-molten
Process	Texaco, Shell, Prenflo	HTW, KRW	Lurgi, BGL

3.3.1.4 Matching Gasifiers and Coals

Depending on the technology, a gasifier can process different type of coal.

Entrained flow gasifiers are very flexible and can process all coal ranks depending on their ash and moisture contents (10% or less is preferred). They are designed to process coals with ash fusion temperatures lower than 1400°C.

Fluidised bed are designed to process also low rank coals with high reactivity and high ash fusion temperatures. As the coal sulphur content can be partly (up to 90%) retained in the bed by sorbents, coal with high sulphur content are allowed to be processed [Collot, 2002].

Moving bed gasifiers have a good flexibility in terms of coal rank but they cannot process coal fines and strongly caking coals. The slagging version of moving bed gasifiers is also not recommended, for coals with a very high ash content and very high ash melting points.

Coal gasification processes used in current power plants (Integrated Gasification Combined Cycle, IGCC) have been designed for a specific coal typology:

Buggenum, Netherlands – This plant adopts the Shell entrained flow oxygen blown gasifier. It was designed for a high quality Australian coal (S: 1%, ash 10%, LHV: 26 MJ/kg) A number of similar coals and coal blends have been gasified successfully. Coal used are within the following ranges: moisture 6-18%, ash (db) 9-16% and S (db) 0.3-0.9%.

Wabash River, USA – The gasification process is based on a two stage entrained flow, oxygen-blown, slurry feed slagging gasifier (E-GAS gasifier). It has been designed to operate on local bituminous coal with a S content of almost 6% (db). Coal is grounded in a rod mill, using recycled water from gasification process.

Polk, Tampa, USA – Texaco gasification technologies is adopted. Coal is fed as a slurry which enters at the top of an oxygen-blown entrained flow slagging gasifier. The plant is conceived to operate on Pittsburgh bituminous coal with a relatively high S content (2.5%). Some tests using different coals have also carried out.

Vresova, Czech Republic – This plant is fed by the local lignitic coal and by a pure oxygen-blown dry-feed. The gasifier type is dry ash moving bed from Lurgi.

Puertollano, Spain – This plant was designed to operate on a mixture of high ash coal and high sulphur petroleum coke. Prenflo oxygen blown gasification technology has been adopted.

Schwarze Pumpe, Germany – The gasification process is based on a moving bed BGL which operate on 50:50 (w%) mixture of waste and lignite. Lignite is dried and briquetted before it is fed into the gasifier together with the waste pellets.

Pinon Pine, USA – It has been designed to operate on high quality coal (bituminous, from south Utah) and it is based on fluidised bed, air-blown gasification.

3.3.1.5 Commercial Gasification Technology

The following section on gasifiers is a summary of a report from the DTI and the NETL web site. [DTI report, 1998; NETL 2004].

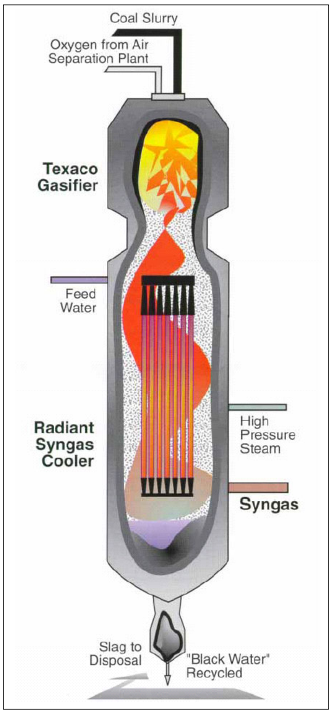


Figure 3.5 – Texaco gasifier

Texaco Gasification Process. - Texaco coal gasification technology uses a single-stage, downward-firing, entrained-flow coal gasifier in which a coal/water slurry (60-70% coal) and 95% pure oxygen are fed to a hot gasifier. At a temperature of about 1500°C, the coal reacts with oxygen to produce raw fuel gas (syngas) and molten ash.

Egas/Destec. – It is a slurry-feed, pressurized, up flow, entrained slagging gasifier with two-stage operation. It is fed by slurry with a dry coal concentrations range from 50 to 70 wt%. About 80% of the total slurry feed and all the oxygen are sent to the first (or bottom) stage of the gasifier. The remaining 20% of the coal slurry is injected into the second stage. The 1000°C hot gas leaving the gasifier is cooled down to 600°C, generating saturated steam which is sent to a steam turbine.

KRW (Kellog/Rust/Westinghouse). - Gasification takes place by mixing steam and air (or oxygen) with coal at a high temperature. The fuel and oxidant enter the bottom of the gasifier through concentric high velocity jets, which assure thorough mixing of fuel and oxidant wit char and limestone. The smaller particles carried out of the gasifier are recaptured in a high efficiency cyclone and returned to the conical section of the gasifier, where they pass again through the jet flame.

Shell Gasification Process. - The Shell Gasification process is a highly reliable and flexible process that can operate on a wide variety of feedstocks. It is a dry-feed, pressurized, entrained slagging gasifier.

The coal reacts with oxygen at temperatures higher than 1400°C producing principally hydrogen and carbon monoxide with little carbon dioxide content. High temperatures eliminate the production of hydrocarbon gases and liquids. The ash is converted into molten slag, which runs down into a water bath, where it solidifies and is removed. In order to make the ash non-sticky, the hot gas leaving the reactor is partially cooled by quenching with cooled recycle product gas. Further cooling takes place in the waste heat recovery (syngas cooler) unit, which consists of radiant, superheating, convection, and economizing sections, where high-pressure superheated steam is generated before particles removal.

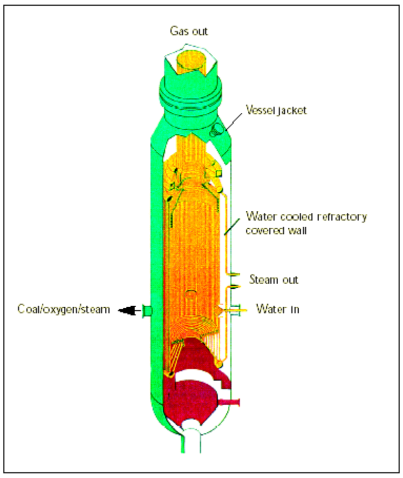


Figure 3.6 – Shell gasifier

Prenflo. – It is based on Shell technology, but has been designed to process low quality coals. The Prenflo gasification process is a pressurized, dry feed, entrained-flow slagging process. As syngas temperature rises up to 1600° C, a quenching process at the gasifier outlet with recycled syngas cools it down to about 800°C. The syngas then flows upwardly in a central distributor pipe and downwardly through evaporator stages before exiting the gasifier at about 380° C. The slag formed during the gasification process flows down to be quenched in a water bath.

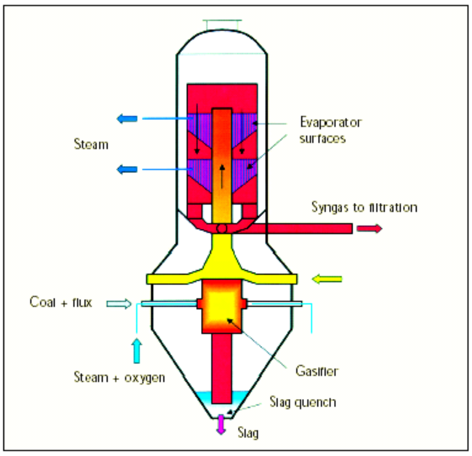


Figure 3.7 – Prenflo gasifier

HTW (Winkler High Temperature). – It derives from the Winkler fluidised bed gasification process. The main feature of this technology is the gasification of waste plastics and lignite coal. Krupp has developed a process, referred as PreCon, where the HTW gasifier is combined with pre-treatment of the wastes and post-treatment of the ash to produce a syngas for chemicals manufacture or power production.

MBEL/ABGC Process. **-** It is an fluidised bed gasifier, designed to reach about 80% carbon conversion, the remaining carbon is burned in a fluidised bed. A 0.5 ton/hour pilot-scale gasifier was built and operated at Stoke Orchard in Gloucestershire.

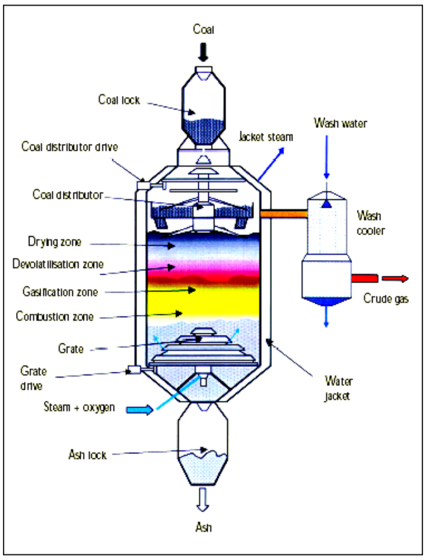


Figure 3.8 - Lurgi dry ash gasifier

Lurgi Dry Ash. **-** The Lurgi dry ash gasifier is a pressurized, dry ash, moving-bed gasifier. The counter-current operation results in a temperature drop in the reactor. Temperatures in the combustion zone near the bottom of the gasifier are about 1100°C. In the top zone, where coal drying and devolatization take place, gas temperature is approximately 250-550°C. In order to condensate TAR, the raw gas is quenched with recycle water. A water jacket cools the gasifier vessel and generates part of the steam required by the process. Sufficient amount of steam is injected to the bottom of the gasifier to keep the temperature below the ash melting temperature. This gasifier can also process biomass and waste.

BGL (BritishGas/Lurgi). **-** The British Gas/Lurgi coal gasifier is a dry-feed, pressurized, fixed-bed, slagging gasifier. Each gasifier is provided with a motor-driven coal distributor/mixer to stir and evenly distribute the incoming coal mixture. The coal mixture (coarse coal, fines, briquettes, and flux) gradually descends through several process zones. Coal at the top of the bed is dried and de-volatilised. The descending coal is transformed into char, and then passes into the gasification (reaction) zone. Below this zone, any remaining carbon is oxidized, and the coal ash content is liquefied, forming slag.

The most convenient process for hydrogen production is the entrained bed gasifier, that operates at higher temperatures (1400-1600 °C) and produces a gas rich in H_2 and CO (gasification with O_2). The utilization of a coal gasification system in a plant with CO_2 capture has been reported by Davison (2003), that analysed different process alternatives based on a dry feed gasifier, such a Shell gasifier, and a slurry feed gasifier, such as the Texaco technology. The solutions based on dry feed gasifier are more efficient, but have a higher specific investment cost.

2.3.2. Gas Clean-up.

The aim of the gas clean up section is to generate a syngas with contaminant within the tolerance limits for combustion turbines and chemical applications. Depending on the coal feed composition, various compounds are generated during coal gasification processes. The main gaseous contaminants are hydrogen sulphide, carbonyl sulphide, hydrogen chloride vapours, hydrogen cyanide, ammonia and heavy metal compounds. The gas outgoing from the gasifier also contains fine dust and ash particulates that are removed by bag filter, wet scrubber, electrostatic precipitator at temperature lower than 200 °C or by ceramic filter, metal filter at temperature higher than 400°C.

Table 3.4 - Gas clean-up processes.

Absorption process	Solvent	
Physical processes		
Rectisol	Methanol	-10/-70°C, >2 MPa
Purisol	n-methyl-2-pyrolidone (NMP)	-10/+40°C, >2 MPa
Selexol	Dimethyl ethers of polyethylene glycol (DMPEG)	-40°C, 2-3Mpa
Fluor solvent	Propylene carbonate	Below ambient temperatures
Chemical process		
Organic (amine based)		
MEA	2.5 n monoethanolamine	~40/120 °C, ambient-intermediate pressures
Econamine	6 n diglycolammine	80-120°C, 6.3 MPa
ADIP (DIPA & MDEA)	2-4 n diisopranolamine, 2n methildiethanolamine	35-40°C, >0.1 MPa
MDEA	2n methildiethanolamine	~40/120 °C, ambient-intermediate pressures
Flexsorb/ KS-1, KS-2, KS-3	Hindered amine	
Inorganic		
Benfield and versions	Potassium carbonate	70-120°C,2.2-7 MPa
Physical/chemical process		
Sulfinol-D and Sulfinol-M	Mixture of DIPA or MDEA, water and tetrahydrothipene (DIPAM) or diethanolammine	>0.5 MPa
Amisol	Mixture of methanol and MEA, DEA, diisopranolamine (DIPAM) or diethylamine	5/40°C, >1 MPa

The water scrubber also takes out the trace quantities of chlorides and heavy metals which may be present in the syngas. The raw fuel gas enters a carbonyl sulphide hydrolizer in order to convert COS and to capture the remaining particulates, ammonia and chlorides. The more conventional methodology for eliminating the COS compound consists in passing the syngas through a fixed bed, catalytic hydrolysis reactor, which will hydrolyze the COS to CO_2 and H_2S and the HCN to NH_3

and CO. After converting the COS, the fuel gas enters to an acid gas removal section. Low temperature chemical/physical absorption is a well known technology, used to remove H_2S, CO_2 from the syngas. The solvent flows down through a tower where the syngas flow up in a counter current way: the solvent captures almost of the syngas acid gases content. In order to separate the acid gases and to regenerate the solvent, it is sent to a stripper tower. In the stripper, due to both an heat input and a pressure reduction, the acid gases are released . The regenerated solvent is finally sent back to the top of the absorption tower. A list of the major gas cleaning technologies is reported in the table below:

An additional process is required to recover the removed H_2S: two different technologies are used, one producing H_2SO4, the other a pure sulphur stream. The most used is the Claus-Scott process which produces elemental sulphur from hydrogen sulphide.

Another stage in the syngas cleanup is ammonia removal. Catalytic decomposition or adsorption on high-surface-area absorbents can be used.

In the following table are reported the main IGCC plant and the related clean-up systems:

Tab. 3.5 – Clean-up systems for commercial IGCC plant [Rosemberg, 2004]

	Wabash power station	Polk power station	Buggeneum power station	Puertollano
Owner	Cinergy/ConocoPhillips	Tampa electicc	NUON	ELCOGAS
Location	Indiana, US	Florida, US	Netherlands	Spain
Particulate control	Candle filter	Water scrubber	Candle filter	Candle filter
Acid gas clean-up	MDEA scrubber	MDEA scrubber	Sulfinol-M	Mdea scrubber
Sulphur recovery	Claus plant	H_2SO_4 plant	Claus plant	Claus plant
Sulphur by-product	Suphur	Suphur acid	Suphur	Suphur
Sulphur recovery	99% design	98% design	99% design	99.8% design

In the Hypogen case, also CO shift and CO_2 capture must be included, with important changes in the gas treatment system (see 3.6).

3.3.3. O_2 production

3.3.3.1 Air separation unit technology overview

High-purity oxygen is a key requirement for many industrial processes and for many advanced energy technologies. Extracting oxygen from the air is both capital and energy intensive and it influences the plant cost. Today, for large-scale oxygen production, massive refrigeration units are required to cool air to about 170 °C below zero, the temperature at which air partially condenses and oxygen can be separated. The efficiency of integrated gasification-combined cycle (IGCC) power generation could be improved by improving oxygen-separation technology. Developing innovative low-cost oxygen technology has been targeted as one of the key research goals of the next decade. Currently the use of oxygen is limited by the high costs of the two predominant oxygen separation technologies: cryogenic distillation for large volumes and non-cryogenic systems for quantities under 100 tons per day [National Research Council, 2000].

3.3.3.2 Cryogenic air separation system.

Cryogenic air separation processes were commercialised early in the 20th century and nowadays are a well developed technology and the most economically efficient for high production rate. The energy required to operate cryogenic plants depends on product purity request [www.uigi.com].

The process: The air is firstly filtered and compressed (to about 6 bar). Water, CO_2 and other contaminants are removed in order to not make them freeze trough the process. An internal heat recovery process cools the inlet stream, warming up the outlet one: the cryogenic temperature is

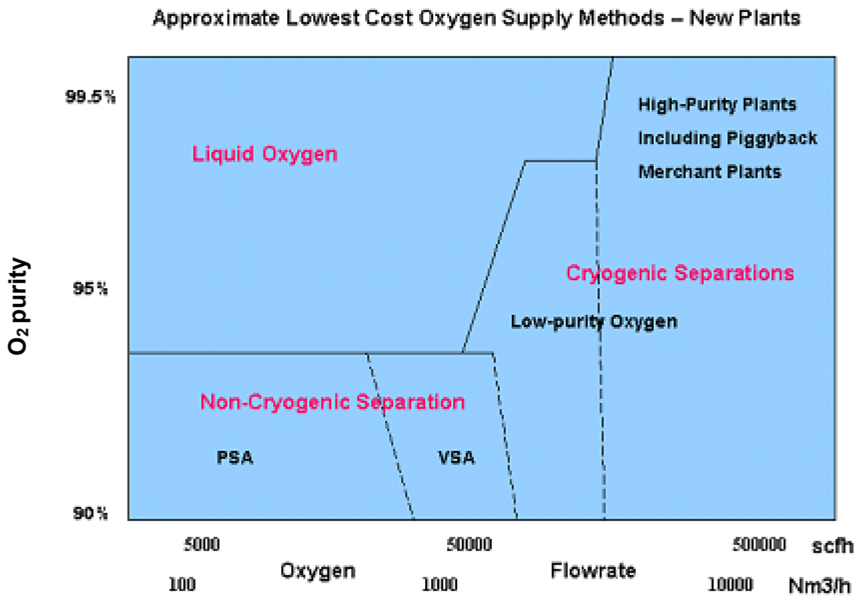


Figure 3.9 – General relationship for the selection of oxygen production plants [www.uigi.com]

reached by sequentially expansions. The heat recovery minimizes the total process energy demand. At cryogenic temperature, distillation columns separate the air into the desired products; oxygen plants have both "high" and "low" pressure columns where impure oxygen from the high pressure column receives further purification in the low pressure column. As argon and oxygen boiling points are close, if high purity oxygen is required, an argon removal column is needed.

A special cryogenic technology are "LIN assist plants" characterised by the absence of an internal mechanical refrigeration system. This arrangement reduces capital costs (versus a conventional cryogenic plant) and provides better overall economics. Figure 3.9 gives some general relations for selecting a new plant producing oxygen.

It reflects typical installation scope, equipment and construction costs, plant efficiencies, financing and power costs over a ten to fifteen year period.

Energy consumption and plant integration: In a Texaco based 500 MW state of the art IGCC power plant, the air separation unit (ASU) is responsible for about 60% of the total auxiliary power consumption (0,20-0,25 kWh/kgO_2) and for about 15% of the overall power plant efficiency [Primicerio, 1991; www.ieagreen.org.uk/emis.6htm]. It is important to integrate the ASU and the IGCC process in order to limit the energy losses in the oxygen production process. Possible integration concerns the air compressor of the air separation and the gas turbine plants [Farina, 1999].

3.3.3.3 Non-cryogenic air separation system

Non-cryogenic air separation processes use physical property differences, other than boiling point. The most common technologies are:

- PSA (Pressure Swing Adsorption);
- VSA (Vacuum Swing Adsorption);

These processes use the different adsorption characteristics of gases on specially-fabricated materials to make the desired separations and operate at close-to-ambient temperature. Non-cryogenic air separation processes are most likely to be a suitable and cost effective choice when high purity product is not required and/or when the required production rate is relatively small. Therefore non cryogenic air separation systems will not play a role in a Hypogen facility.

Pressure Swing Adsorption - The adsorption material in oxygen service is a variety of zeolite molecular sieve which selectively adsorbs nitrogen, moisture, and carbon dioxide gas, while allowing oxygen molecules to pass through the unit. Typical product purities for oxygen are 90 to 95%.

Vacuum Swing Adsorption - These units are used to produce low purity oxygen, typically at 90 to 93%. While the process cycles is similar to that used in PSAs, the sieve materials operate over a different pressure range. During desorption, the beds are de-pressured to vacuum conditions with the aid of vacuum pumps. While the vacuum portion of the pressure swing consumes a significant amount of power, it allows the sieve material to be fully regenerated, which increases the overall process efficiency by lowering the amount of feed air, the required feed air pressure, and air compression power. Because the product delivery pressure is low, VSAs almost always require an oxygen product booster or compressor. Capital and maintenance cost increase despite of the lower separation power request. Specific power is comparable to cryogenic air separation systems [www.uigi.com].

3.3.3.4 New future technologies.

Ion Transport Membrane (ITM) - This innovative gas separation technology is based on a class of dense ceramic materials called "ion transport membranes." At high temperatures (800-900 °C), these substances have the unique property of electrically charging oxygen molecules in the air using electrons that have migrated to the outer side of the membrane. The oxygen ions then pass through the wall of the ceramic membrane. On the inner side of the membrane, the ions reform into a stream of pure oxygen, releasing electrons that travel back through the membrane to repeat the ionising process with incoming oxygen. ITM technology applied to a IGGC plant should reduce capital cost by 7%, and increase power production by 7%. ITM also allows to save up to 35% in the air separation installed unit, to improve by 37% the oxygen plant energy demand and to increase by 2.2% the overall power plant efficiency [www.netl.doe.gov]. ITM may become an important option for the future, however the actual status is basis R&D and therefore they are not suitable as part of the Hypogen facility.

3.4 Hydrogen production from heavy oils

Gasification processes are not limited to coal, but can be also used very effectively for producing hydrogen rich gas for generating electricity from other solid or heavy liquid fuels like petroleum coke and other refinery residues, which are fuels with high sulphur content and heavy metal contamination. The principal advantages are the relatively low cost and high energy content of these fuels. Depending on the refinery processing techniques used, residues either take the form of liquid products such as heavy oil or liquid vacuum residues or solid products like petroleum coke. For example the Puertollano IGGC plant is fed by a mixture of coal and petroleum coke.

With regard to refinery residues (bottoms), these can take several forms depending on the design of the refineries and on their products. The primary bottoms that comprise most of the fuels of interest for energy application include:

- Atmospheric distillation residues,
- Vacuum distillation residue,
- Residual tar from solvent deasphalting/visbreaking process,
- Petroleum coke.

Although much attention has been focused on using coal as the primary feedstock, the large majority of gasification projects in Europe to date are based upon the use of fuels other than coal, as shown in the tables 3.6, 3.7 and 3.8. There are, however, many ongoing or planned gasification projects with coal in China.

Table 3.6 - Major operating electricity producing gasifiers by country

Country	Plant Name	Type	Feedstock	Products	Year
Germany	Leuna Methanol Anlage	Shell	Visbreaker residue	H2, Methanol, Electricity	1985
Germany	Slurry/Oil Gasification	Lurgi MPG	Oil & Slurry	Electricity & Methanol	1968
Italy	Project	Texaco	ROSE Asphalt	Electricity, H2 & Steam	2000
Italy	SARLUX GCC/H2 Plant	Texaco	Visbreaker Residue	Electricity, H2 & Steam	2000
Netherlands	Pernis Shell Gasif. Hydrogen Plant	Shell	Visbreaker Residue	H2 & Electricity	1997
Singapore	Chawan IGCC Plant	Texaco	Residual Oil	Electricity, H2 & Steam	2001
Spain	Puertollano GCC Plant	PRENFLO	Coal & petcoke	Electricity	1997
USA	Delaware Clean Energy Cogen.	Texaco	Fluid petcoke	Electricity & Steam	2001
USA	New Bern Gasification Plant	Chemrec	Black liquor	Electricity	1997
USA	Wabash River Energy Ltd	E-GAS	Petcoke	Electricity	1995
USA	El Dorado IGCC Plant	Texaco	Petcoke, Ref. Waste &	Electricity & HP Steam	1996

Source: Derived from the World Gasification Database, US DOE and Gasification Technology Council.

Table 3.7 - Major planned electricity producing gasifiers by country

Country	Plant Name	Type	Feedstock	Products	Year
India	Bathinda IGCC	Texaco	Petcoke	Electricity	2005
Italy	Agip IGCC	Shell	Visbreaker residue	Electricity & H2	2003
Italy	Sannazzaro GCC Plant	Texaco	Visbreaker residue	Electricity	2005
Japan	Marifu IGCC Plant	Texaco	Petcoke	Electricity	2004
Japan	Yokohama Cogen/B	Texaco	Vac residue	Electricity	2003
Poland	Gdansk IGCC Plant	Texaco	Visbreaker residue	Electricity, H2 & Steam	2005
Spain	Bilbao IGCC Plant	Texaco	Vac residue	Electricity & H2	2005
USA	Port Arthur GCC Proj	E-GAS	Petcoke	Electricity	2005
USA	Lake Charles IGCC Proj.	Texaco	Petcoke	Electricity, H2 & Steam	2005
USA	Deer Park GCC Plant	Texaco	Petcoke	Electricity, Syngas & Steam	2006
USA	Polk Country Gasification Plant	Texaco	Petcoke	Electricity	2005

Source: Derived from the World Gasification Database, US DOE and Gasification Technology Council.

Table 3.8 - Feedstocks used in gasification plants.

Feedstock	Operational plant	Planned plant
Coal	27	17
Coal / petcoke	3	1
Petcoke	5	7
Natural gas	22	0
Biomass	12	3
Fuel oil / heavy petroleum residues	29	2
Municipal waste	5	0
Naphta	5	0
Vacuum residue	12	2
Unknown	40	6
TOTAL	160	35

Source: Derived from the World Gasification Database, US DOE and Gasification Technology Council.

3.5 Power production

The following paragraph gives a brief description of the main thermal cycles currently used for producing energy. Also a description of some interesting innovative cycles, which could represent short term solutions for high efficiency power plants, has been included.

3.5.1 Conventional Thermal Cycles

3.5.1.1 Bryton cycle

It characterizes the gas turbine cycle. The thermal cycle efficiency is strongly influenced by the gas turbine inlet temperature and pressure. Those value are strictly related to the material technologies and many R&D effort are focalised in developing special alloys and blade cooling system in order to reach higher top temperature.

The top status of art of this technologies reach 30 bar as top pressure (for marine engine), and 1500°C as top temperature value. The maximum plant size is about 150 - 200 MW of electric production. The efficiency value are around 30-40% depending on the application and operative condition. Standard efficiency value for energy production is 35% [www.europa.eu.it].

The technology and market trends are oriented in increasing the efficiency, developing small size solution for a distributed energy production. Big size plants are generally part of a combined cycle. Power plant based on this cycle are essentially fed by gaseous fuels. The gas can be both natural gas or syngas coming from a biomass or coal gasification process.

3.5.1.2 Rankine Cycle

Rankine cycles are mainly adopted as solution in large scale electricity production plants. The cycle is characterized by the steam top temperature and pressure: both these factors strongly influence the plant efficiency and they strictly depend on material technology level. The number of steam superheating steps also increases the efficiency. Another important feature in the steam cycle is the boiler pressure, that defines the steam cycle typology and operating conditions: 1) sub critical solution, where the steam pressure is lower than the steam critical pressure. It operates at max temperature and pressure of 580°C and 170 bar with an efficiency lower than 40%; 2) supercritical solution, in which the steam pressure is higher than the critical one, reaches 260 bar at 600°C, with an efficiency up to 43% [Rousaki, 2000].

As example of supercritical steam plant we can consider Tachibana – Wan, with 1050 MWe production divided in two units (steam cycle based power plant can reach unit size of 800 MW or even higher). R&D effort are concentrated in developing stronger steal alloys that can allow to reach higher temperature. In the short term it is expected to reach efficiency of 47-50 %.

Power plant based on the steam cycle can be fed with different fuels: the fuel type characterizes the cycle operative conditions and plant configuration: using low quality coal or biomass, it is possible to reach an efficiency of 43 % operating at 580°C and 250 bar. Almost 35% of worldwide electric production derives from steam power plant coal fed.

3.5.1.3 Combined Cycle

It is a combination of Bryton and Rankine cycle. Fuel (usually natural gas) is burned in the gas turbine. The hot exhaust gases are send to a heat recovery boiler to produce steam for additional electricity production via a conventional steam turbine-generator. Efficiencies of up to 58% can be achieved by large, new power generation units.

Combined cycle application can be found in some power plant re-powering: two different applications can be identified: "topping" or "parallel re-powering". In topping applications, the gas turbine exhaust is used as boiler combustion air; in parallel re-powering it is used to generate additional steam. New combined plant of this type can achieve efficiencies of at least 46%.

Different plant solutions derive from the combined cycle. In particular these are:

Natural Gas Integrated Combined Cycle (NGICC)**:** It is a sort of "topping re-powering application". The hot exhaust gases from the GT can be routed into the existing boiler where additional natural gas can be burned to allow the original power station to achieve its design output

Natural Gas Combined Cycle (NGCC): It is the typical combined cycle application. Natural gas-fired gas turbine (GT) is used to generate electricity, and the waste heat from the GT is used to produce steam to generate additional electricity via a steam turbine. Multiple pressure levels are generally used in the steam recovery boiler, in order to increase the overall plant efficiency. NGCC technology is already widely used in many parts of the world.

During the past decade NGCC plants have been chosen as the technology for new and replacement power plant in the EU; till the year 2020, NGCC is expected to rise to over 30% of Europe's installed capacity. Reasons include: 1) low capital costs; 2) high levels of generating efficiency; 3) low emissions levels; 4) the development of combined cycle systems suited to base load applications; 5) the continued availability of low cost natural gas.

Ongoing technology development and near term introduction of a new class of turbines will improve gas turbine efficiency up to 40% (considering large size unit, 250 to 359 MW), The combined cycle would approach efficiency of about 60%, with a plant capacity within 375 and 500 MW [The World Bank, 1999; Sunao Aoki, 2000].

Integrated Gasification Combined Cycle (IGCC): The gas fired in the GT is produced via a gasification process of solid or liquid fuels. The purpose is to utilize low value fuels to produce electricity with high efficiency. The cycle is known as an Integrated Gasification Combined Cycle (IGCC). IGCC's are able to convert "difficult" liquid and solid fuels to electricity at high efficiencies and with low emissions. As there is not yet a significant number of plants in operation (so that the cost and performance characteristics or a standardized commercial design are not well-established), there is considerable variability in technology cost estimates. Different gasifier technologies, and fuel feedstock, have different cost and efficiency characteristics. Consequently, a generalized cost or efficiency estimate for technology may not be representative of all systems. The capital cost estimates range from around $1,100/kW to over $1,700/kW and the efficiencies range from 32 to 45.5 % [Rosemberg et al., 2004]; with technology and cycle improvements, net efficiencies could reach 51-52%. Cost data from the existing demonstration IGCC plants in the U.S. and Europe, Wabash, Polk, and Buggenum, are at the high end of the range. One variable that affects IGCC costs and efficiency is the rank and quality of the coal feedstock. Generally, bituminous coal and petroleum coke fuel imply the lowest-cost IGCC operation. These higher rank coals can be gasified most efficiently, which reduces the required size (cost) of fuel handling and gasifier equipment. Up to date, the main target of IGCC plant is use low quality coals.

There are also barriers to the widespread adoption of IGCC plant: 1) some unresolved technical issues related to plant components and integration; 2) the capital cost of IGCC plant and the need for greater plant efficiency; 3) competition from other clean coal technologies, in particular advanced PF combustion and PFBC; 4) the inherent conservatism of the power utility companies when faced with new technology.

The best reference plant for the IGCC technology, can be considered the Puertollano 300 MWe plant. The following tables show economic and operation parameters for particular combined cycles.

Table 3.9 - Combined cycle economic and operative parameters

Plant	Description	Efficiency	Electricity cost (c€kW)	Capital cost per kW	Status of Art	Unit size (MW)
NGICC	Natural Gas Integrated Combined Cycle	45%	3.99	<330 (€/kW)	Mature	200-600
NGCC	Natural Gas Combined Cycle	60%	3.70	<500 (€/kW)	Mature	250-360
IGCC	Integrated Gasification Combined Cycle	46%	3.64	<1400 (€/kW)	Demon-stration	150-600
HAT	Humid Air Turbine applied to an IGCC	49%	3.80	<1600 (€/kW)	R&D	150-600
HTGC	High Temperature Gas Cleaning	R&D	R&D	R&D	R&D	R&D

Source: http://europa.eu.int
Electricity cost has been determined assuming 25 years as plant life time, 8% as discount rate, plant size 300 MW, 3.56$/GJ as NG price, 1.31 €/GJ as coal price

Table 3.10 – Selected Published IGCC Capital Cost and Plant efficiency [Rosemberg, 2004]

Demonstration plant	Gasifier technology	Capital cost [$/kW]	Efficiency [%]
Wabash Generating Station	Conocophillips	1680	40%
Polk power station	GE Energy quench	1790	37%
NUON IGCC plant	Shell with heat recovery	1750	41.5
Puertallano IGCC	PrenFlo	1400	42%

3.5.1.4 Humid Air Turbine (HAT)

The idea is based on increasing the GT power output (within limits) by increasing the gas mass flow. In the case of an IGCC the fuel gas can be cooled by saturating it with steam. This increases the mass flow of gas through the GT's turbine. This effect can be taken further by injecting steam from the waste heat boiler into the GT upstream or in the combustion chamber. Such cycles are known as Humid Air Cycles. This different conversion route can produce a rise in efficiency of about 3% points compared to a standard IGCC plant, depending on the precise cycle parameters. Needs for development are still great: there are no commercially available GT's suited to this application. It is important also to note that steam injection reduces the NOx emission rate [www.europa.eu.it].

3.5.2 Non-Conventional Thermal Cycles

Due to the social, political and economic worldwide awareness concerning greenhouse gas emissions, more and more process are being considered that include CO_2 removal in some form. These cycles are essentially based on the adoption of O_2 as fuel oxidizer, so that the obtained combustion gas is largely rich of CO_2 and H_2O, that can be easily separated. As a direct consequence, the power plant has to be integrated with an air separation unit (ASU), and the working fluid is a mix of CO_2 and steam. Due to the strong difference of the work flows, compared to those of conventional power cycle, many efforts have to be devoted to develop the appropriate technology, as conventional components are not able to suit the process.

Non conventional thermal cycles can be classified depending on the working medium. Two main cycle classes are individuated:

1) Water cycle, GRAZ cycle: the working fluid is essentially composed by water with a small amount of CO_2

2) CO_2 cycles, AZEP (Alstom/NorskHydro); HiOx (Aker Kvaerner); MATIANT. The working medium is CO_2.

Water cycle: Hydrogen is burned with pure oxygen. The combustion product is almost pure water (steam); other compounds are present if hydrogen comes from a fossil fuel gasification process. Water Cycle are characterized by high efficiency value but the main components of the plant are still in R&D phase. Several projects are ongoing concerning *water cycle* solution. A particular typology of water cycle is studied also in ENEA (Italy). The adopted solution is a sort of combined cycle in which the working medium of the topping and bottoming sections are both steam: this cycle has a thermodynamic efficiency of 65%. Also in Japan some theoretical and experimental analysis are being carried out in the frame of projects managed by JAERI and NEDO [Gambini, 2003].

GRAZ Cycle: Fuel is burned with almost pure oxygen: the working medium is a mixture of H_2O and CO_2 instead of steam and exhaust gas. It combines the advantages of gas turbine cycle (high peak temperatures) and steam cycle (compression of the working medium in the liquid phase). This results in higher cycle efficiencies. Critical points in adapting the current technology to this plant solution are the combustion chamber and the high temperature turbine. Other plant components are available on the market. The cycle can reach a thermal efficiency of 52.5 % and the plant exhaust is almost pure CO_2.

AZEP: The AZEP concept proposes a less energy-intensive (and hence more cost-effective) system for zero emissions power. The key to this is the Mixed Conducting Membrane (MCM), which produces pure oxygen from air. MCM-Reactor is integrated with a conventional gas turbine. Essentially, the MCM-Reactor, which combines oxygen-separation, combustion and heat transfer processes, replaces the conventional burner in a standard gas turbine power plant thereby creating the AZEP (Advanced Zero Emission Power Plant). The gas turbine and its auxiliary equipments are available on the market and do not need further research and development activities. The major research and development efforts has to be concentrated upon the new components within the MCM-Reactor, thereby limiting the need for the development of an entirely new cycle - and its associated new equipments - and substantially reducing technical and commercial risks. [Sundkvist, 2001]

Matiant: The working medium is a CO_2 stream, produced by the combustion of the fuel with a pure oxygen stream. The CO_2 is extracted from the plant at high pressure level and ready to be stored. Its relative low efficiency value (45%) take into account also the energy necessary to capture and extract the CO_2. It operates at high pressure level (150 bar) with a top temperature of 1300°C. The cycle has been developed looking at the component technological limits, but the status of art is not at industrial level. The cycle could be easily coupled with a gasification process keeping an high efficiency value: it does not require the CO_2 chemical adsorption and the CO shift reactor.

3.5.3 Using Hydrogen as Gas Turbine Fuel

Several research activities [Chiesa, 2003] allow a positive answer to the issues related to hydrogen combustion in modern gas turbines. The main issue is to comply with NO_x emission. Taking into account the hydrogen combustion characteristics, abating the stoichiometric flame temperature to about 2300 K seems necessary without incurring in excessive operating costs of the end-of-pipe $deNO_x$ systems. This is possible without dramatic performance losses by means of a massive fuel dilution with steam or nitrogen (the latter providing minor losses of efficiency). Usually H_2 fed cycle are integrated with an air separation unit required by the H_2 production process, and as N_2 is already produced as a by product, it is cheaper than steam. Different strategies have been envisaged to operate the gas turbine in presence of dilution. Choosing the appropriate strategy for matching the compressor and turbine operative conditions, efficiency losses can be limited to 0.9 points for nitrogen dilution and 1.9 for steam dilution. Considerations on system costs, lead to adopt steam dilution for reducing capital cost compared to nitrogen, even if it may provide lower efficiency. If the power plant is integrated with an air separation unit, the adoption of N_2 dilution have to be considered. It has to be noticed that several gas turbines have been adapted to work with a syngas rich of hydrogen (about 45% in volume). Several IGCC plants use current gas turbines to burn H_2 rich syngas coming from coal or refinery residues gasification processes. The use of a syngas with higher hydrogen content needs substantial burner adaptation because hydrogen flame speeds are about one order of magnitude higher than that of natural gas, the ignition limits are wider and reaction time is about one fifth of that of natural gas.

3.6 CO_2 capture

During the last 6 years, work on capture and storing CO_2 to reduce carbon dioxide emissions from power stations have been increasing rapidly. Carbon capture technology can be seen as bridging technology until the electricity production from renewable energies can replace fossil fuels to a significant extent. The aim of Carbon capture and storage is to make fossil fuels compatible with power generation in a carbon constraint world.

In the following, a short overview is given on the technologies, which are described in much more detail in the literature. Therefore only the important points related to the plans to build a Hypogen facility within the next ten years will be discussed. The three types of capture technologies can be given as:

(1) Post Combustion Capture

(2) Pre Combustion Capture

(3) Oxyfuel Combustion

For all three routes, different technical solutions exist; sometimes the differences are of minor nature, e.g. post combustion solutions with essentially the same process and only differing amines. In all three cases the main difficulty lies in the required separation of material streams.

In the case of post combustion capture, the separation task is to isolate the CO_2 from a (flue-) gas stream, containing mainly nitrogen and other combustion products. CO_2 concentrations are typically in the range of 8 and 14 Vol -% CO_2, which corresponds to a partial pressure of CO_2 of around 0,1 bar.

In the case of pre-combustion capture, the separation is made prior to combustion, therefore the task is to isolate CO_2 out of a syngas stream, containing mainly hydrogen. In the syngas the CO_2 concentration is typically around 30 % with a total pressure of the syngas of around 40 to 70 bar. This means that the partial pressure of the CO_2 is about 15 to 20 bar.

In the case of oxygen combustion, the separation is shifted fully to the front end. The separation task is to isolate the oxygen from the air, enabling a combustion producing a gas stream in which the CO_2 is the only non condensable component.

When trying to evaluate the potential of the three different kinds of processes, a first order analysis can be made based on the principles of the second law of thermodynamics. In a simple form it can be expressed for the separation task as such that the higher is the concentration of CO_2 in the gas stream, the lower will be the energy penalty related to the separation. Separating the CO_2 out of the atmosphere in which the concentration is about 0.03 % would require much more energy than separating it out of a synthesis gas with a concentration of about 30 % of CO_2. As can be drawn from the chart (Figure 3.10) it is therefore also obvious, that the capture of CO_2 from industrial processes such as the steel process or the production of cement and lime will cause a much smaller penalty than capturing CO_2 from power stations.

By looking at the power generation processes only, capture from synthesis gases together with oxyfuel combustions looks most promising with a small advantage for separation from synthesis gas. This is especially true as synthesis gas produced in an IGCC plant will be at much higher total pressures than 1 bar, therefore the partial pressure of CO_2 in the gas stream will be typically above 1 bar, reducing the minimum exergy demand for separation. However, it should be kept in mind that the efficiency achieved in real plants can be much lower than the values calculated based on the second law of thermodynamics due to non-idealities in the process.

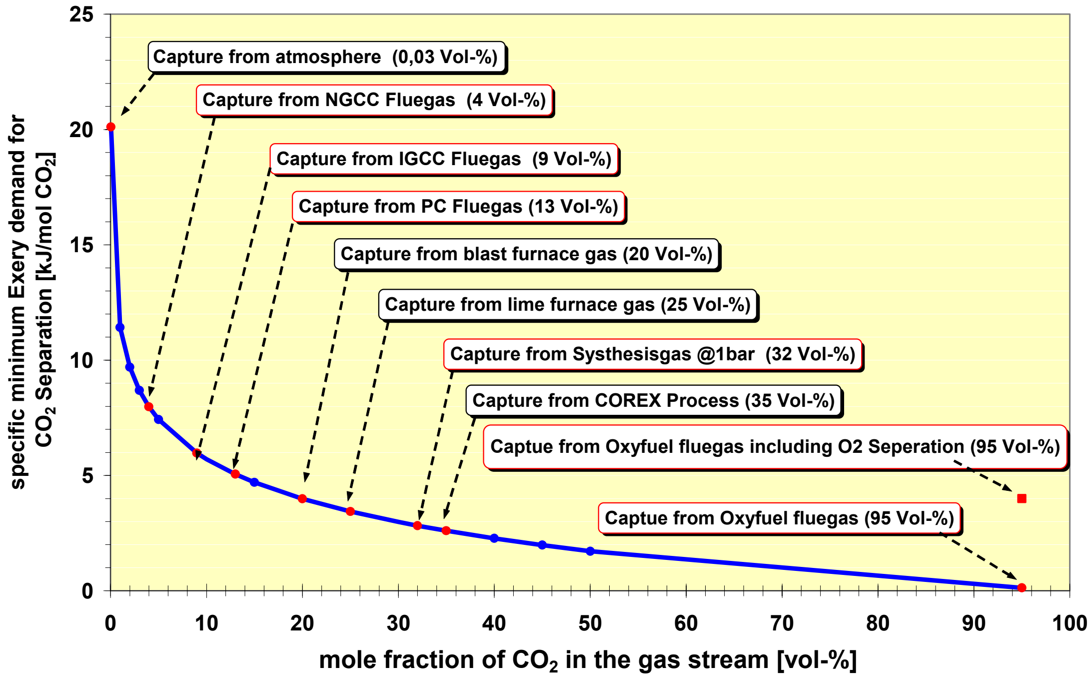


Figure 3.10 - Minimum exergy requirement to separate CO_2 out of a gas stream

All three technology options are in principle compatible with all fossil fuels, ranging from natural gas over oil to the different types of coal. However, there have been different track records and different cost associated with these technologies. Table 3.11 summarizes some main issues regarding the technologies.

From the table it becomes obvious, that if the production of Hydrogen is a necessary condition, there is no way going around pre combustion capture, as the two other technology options do not allow the production of Hydrogen in the process. However, if a capture plant has to be built as quick as possible or the capture rate should be as close as possible to 100 %, and if mainly large scale carbon capture and storage from a power station has to be demonstrated, post combustion solutions might be the better choice. The main disadvantage actually seen for post combustion is the high level of energy and cost penalty for the addition of a capture unit to the process. This penalty could lead to a development that post combustion technology will not become a widespread used technology for newly built power stations. It should be not forgotten though, that despite of this, post combustion technologies might play an important role for retrofitting.

Table 3.11 : Technologies for CO_2 capture

	Post Combustion	**Pre Combustion**	**Oxy Firing**
Separation Task	CO_2 / N_2	CO_2 / H_2	O_2 / N_2
Main Technology	Amine Scrubber	Physical Solvent Scrubber (e.g. Selexol, Rectisol) Air Separation Unit	Air Separation Unit
Technology Development underway	New/advanced Solvents	H2 Gasturbine H2 Membranes Gasifier	Burners Membrane Separation
Energy Penalty (actual designs)	about 14 %	about 12 %	about 12 %
Hydrogen Production	no	yes	no
Proven Technology	yes, but not at this scale	partly	no
CO_2 Capture rate	≈90 %	≈ 90 %	>95 %
Possible Cycles: Coal Gas Biomass	 RC CC RC	 CC CC CC	 RC CC RC

RC Rankine Cycle; CC Combined Cycle

On the other hand, oxyfuel technologies and pre combustion technologies will compete for newly built power stations. A major advantage of oxyfuel technologies lies in the much simpler plant configuration, making it cheaper to build and allowing operating it with higher reliability. Both of these elements are of high importance in a liberalized electricity market. The main disadvantage compared to pre combustion capture solutions is the possibility to use coal and biomass in a rankine cycle only. Making use of a rankine cycle limits the maximum efficiency to a much lower level compared to a combined cycle.

If the projections for the power market e.g. of the IEA are taken as a baseline, the evaluation of coal technologies might not be worth thinking about. There, it is concluded that most of the new capacity will be built on gas and not on coal. However coal is the most abundant fossil fuel and its resources are widespread distributed throughout the world. Therefore, in order to improve the security of supply it is essential to develop a strategy to use coal at highest efficiency levels and without CO_2 emissions. Such strategy would lead to the conclusion that pre-combustion technology will keep up most options, including the step towards a Hydrogen economy.

The different technical components required for pre combustion capture are well developed with only some pieces of the puzzle missing. This is mainly a gas turbine which can operate with a hydrogen rich fuel. However besides the availability of the technical components, the integration of gasification or reforming, gas treatment including carbon dioxide capture and the combined cycle operating on a hydrogen rich gas are still not proven.

Table 3.12 -Comparing pre combustion capture for coal and gas

Pre Combustion	Coal	Gas
Gas generation	O_2 blow gasifier	Steam methane reformer/ATR
Air Separation Unit	Yes	No
Desulphurization necessary	Yes	depending on gas quality
CO2 Separation	Physical Solvent	Physical Solvent
Reliability	typically above 85 %	above 95 %

Table 3.12 shows the main differences depending on the type of fuel to be used. If no hydrogen is required, the plant complexity will be reduced and the gas turbine for a hydrogen rich gas becomes unnecessary. In addition if flexibility is required to shift the production between hydrogen and electricity, overall efficiency will be reduced.

Another important point to be discussed is the best CO_2 capture rate. If CO_2 emission reduction is the goal, the capture rate should be as high as possible, as the amount of CO_2 avoided per kWh produced increases more strongly than the efficiency loss of the power station when reaching high capture rates. A completely CO_2 emission free Hypogen facility is impossible but it could be an ultra clean plant with very low specific emissions.

To determine the maximum capture rate it is not advisable to look only at the capture plant, which can reach CO_2 capture rates up to 99,5 %. Instead one needs to look on the overall carbon capture rate as there will be still some CO in the synthesis gas. This CO will not be captured in the capture plant and will end after combustion as CO_2 in the atmosphere, lowering the total capture rate of the plant. The capture plant can be designed to reach a CO_2 capture efficiency up to 99,5 % without a drastic cost increase compared to lower rates around 90%. This holds true for physical and chemical capture plants.

The total carbon capture rate which can be achieved is much more dependent on the shift conversion. State of the art is a two stage shift reaction with intermediate cooling. The two stage high temperature shift takes place at around 400 °C. If a low temperature shift is added the shift operates typically at around 230 °C. The shift reaction is exothermic; therefore inlet temperatures are typically lower than outlet temperatures. High and low temperature shifts are catalytic reactions.

The low temperature shift catalyst is very sensitive to sulphur and expensive and must be replaced regularly due to degradation in activity.

The shift reaction given below takes only place significantly at elevated temperatures.

$$CO_{(g)} + H_2O_{(g)} \Leftrightarrow CO_{2(g)} + H_{2(g)} \qquad \Delta H^o = -41{,}2 \frac{kJ}{mol}$$

However as the shift reaction is exothermic, this will move the thermodynamic equilibrium to the left side of the equation, hindering the full conversion of the CO to CO_2.

The CO however can not be captured and will therefore leave the plant. A high CO slip in the shift reactor will therefore reduce the overall capture rate significantly. Figure 3.11 shows the equilibrium composition of a synthesis gas at a pressure of 3.61 MPa. As can be seen, the share of remaining CO at temperatures of 350 °C is about 5 to 7 %, whereas at 240 °C it will drop to about 1 %.

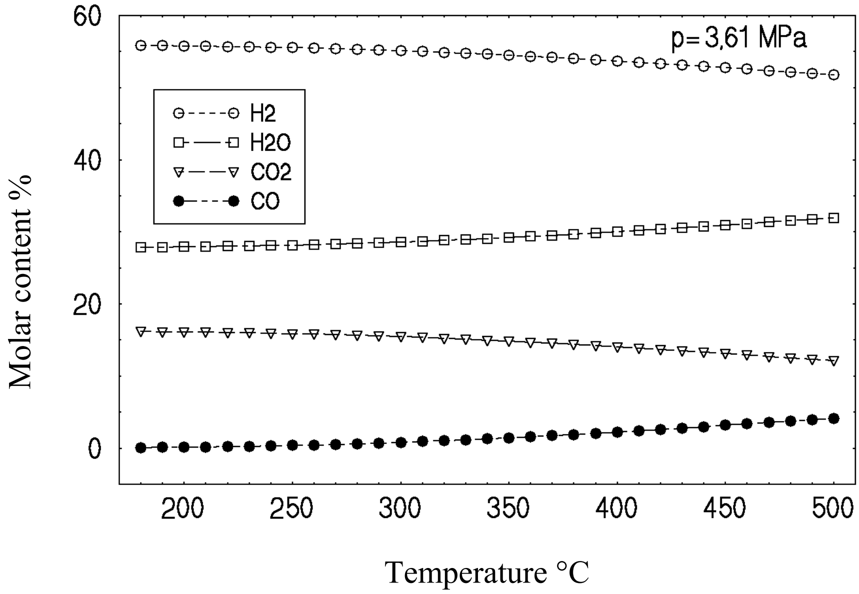


Figure 3.11 - Equilibrium composition for a synthesis gas for NH_3 production, based on natural gas steam reforming. Inlet composition: CO 10,88 mol-%, CO_2 5,41 mol-%, H_2 45,05 mol-%, H_2O 38,66 mol-% [Radgen, 1996]

The capture rate is therefore mainly determined by the choice to include a low temperature shift conversion in the concept or not. Overall capture rates of 95 % and higher will require in any case a low temperature shift conversion.

For the Hypogen facility to be built it seems to be a good approach to have a low temperature shift incorporated in the concept, as this will have a high impact on the maximum CO_2 capture rate. The additional cost will be paid of, if the avoided CO_2 will have a price between 10 and 20 Euro per ton [Koss, 2004].

For a power station of 350 MW operating 6500 h/yr a difference of 1 % in the capture rate will be equivalent to about 16000 t CO_2 /yr captured or released to atmosphere. For a possible Hypogen facility the economics of the low temperature shift will therefore depend on the fact, if the CO_2 capture will be used for EOR or will be stored in an aquifer.

Selection of the gas treatment processes for an IGCC

As reported in 2.3.2, the introduction of the CO_2 capture substantially modifies the gas treatment of an IGCC that is generally separated in three packages:

- The CO shift reaction followed or preceded by the removal of trace contaminants such as HCN, NH_3, carbonyls, COS, naphtalen, BTX and others,
- the desulphurization,
- the CO_2 removal.

Either the trace contaminants are removed together with other components in the main processing units (CO shift, desulphurasition, decarbonisation) or designated process units have to be added.

COS

All amine processes can be used for H_2S absorption but will not remove COS. The physical solvents Selexol and Purisol will absorb only about 20 % of the COS, therefore an IGCC plant using an amine wash or a Selexol wash will need an additional unit, the COS hydrolysis reactor. However a Rectisol wash will remove the COS from the gas.

H_2S, CO_2

H_2S and CO_2 show a quite similar behavior which is responsible for the fact, that in the physical or chemical wash for H_2S-removal typically a significant share of CO_2 is captured at the same time. The problem to be solved is the balance to remove the contained H_2S to the extend required and to co capture as less as possible CO_2.

Table 3.13 shows the selectivity for different solvents which can be used for the gas treatment. The choice to be taken for a Hypogen facility is therefore to choose between an highly integrated Rectisol solution and a Selexol or Amine solution extended with additional helper units to deal with the trace contaminants. A detailed analyses of this issues are actually underway in the EU funded ENCAP project.

Table 3.13 - Removal capacities of different solvents [Koss, 2004]

Component	Solvent		
	Selexol / Purisol	Rectisol (liquidMethanol)	Amine
H_2S	high	high	high
COS	low	high	low
CO_2	low	high	high

In addition it should be kept in mind that besides the Rectisol wash all solvents are water based, therefore CO_2 streams coming from a wash with these solvents are saturated with water. Therefore an additional unit for drying the CO_2 stream is required, whereas for the Rectisol wash this is unnecessary due to fact that Rectisol is a water free solvent.

To get a look into the future with carbon capture and storage the question may arise, if an IGCC can be build capture ready. In principle this would be possible. Shift reactors and a CO_2 absorption unit can be included later on. However as Selexol and Purisol washes have been especially developed for high selective H_2S absorption with low CO_2 absorption, an additional wash together with other units have to be added for CO_2 capture. It seem however not realistic, that a capture ready plant could be changed to the Rectisol process.

3.7 CO_2 Transportation

The transport options suitable for the quantities of CO_2 being produced at a Hypogen facility would mainly be pipeline transport for onshore distances and ship transport for the offshore area. The transport in large railway trains could be feasible for onshore distances as well (compare Odenberger and Svensson, 2003). The specific costs estimated for railway transportation were considerably higher than for pipeline transportation. For this reason, railway transportation will not be considered in this study.

3.7.1 Pipeline Transportation

The large scale pipeline transportation of CO_2 for enhanced oil recovery (EOR) has been performed in the United States since the 1980s. The demand for CO_2 for EOR projects especially in Western Texas has lead to the construction of the worldwide largest network of CO_2 pipelines.

In total, there are about 2400 km of main pipelines for CO_2 in the United States. Worldwide, there are about 3100 km of CO_2 pipelines with a transport capacity of about 45 million tonnes of CO_2 [Gale and Davison, 2002]. Compared to the pipeline networks for other gases (e.g. with 800,000 km length in the U.S.), the existing CO_2 pipeline network is of minor extent.

The technical requirements of a CO_2 pipeline can be derived largely from the example of natural gas pipelines [Skovholt, 1993] with the main elements:

- Piping with high quality coated carbon steel, protected against exterior corrosion and mechanical damaging,
- Initial compressor station,
- Pumping or recompression stations,
- Section valves and security valves,
- Cathodic corrosion protection,
- Stations for corrosion monitoring.

In order to reach the highest possible mass transfer in a given pipeline diameter, the CO_2 should be conditioned into a state of high density. The most suitable solution for this requirement is to compress the CO_2 up to the supercritical or dense phase. Although technically it is not a liquid, CO_2 in dense or supercritical phase has comparable characteristics and an even higher density than in liquid phase. Consequently, a pipeline should be planned such that the pressure in the pipeline stays above the critical pressure of 7.38 MPa along its entire length. With a safety margin the pressure demand is stated as high as 8 MPa [Egberts et al. 2003]. A pressure drop is occurring in the pipeline due to the flow friction making recompression of CO_2 necessary at compressor stations along the way. According to Heddle et al. (2003), recompression will be needed for distances larger than 150 km. There are cases in the United States of longer distances without recompression, realised by a downward slope of the pipeline. Another alternative avoiding recompression is to compress CO_2 to the higher pressure at the beginning of the pipeline according to the ratio of pressure drop and the pipeline distance.

At the given state of the study it is very difficult to give accurate cost information for pipeline transportation of CO_2. The reason for this lies in the high investment cost share of this mode of transport. The investment costs in turn are highly dependent on the geographic situation encountered along the pathway of the pipeline. Influencing factors driving up the costs are especially the terrain, roads or rivers that have to be crossed and even more cities that have to be crossed. Some rough indication can be given based on the economic analysis performed by Heddle et al. 2003. The results and given in table 3.14.

Table 3.14 - Cost estimations for CO_2 transport in pipelines.

	total annualised cost for pipeline, mill €	Total costs €/t CO_2 (for 1 Mt CO_2/year)
Pipeline, 100 km	3.936.128	3,94
Pipeline, 300 km	12.585.412	12,59

<u>Risks and safety</u>

During transportation major amounts of CO_2 could escape from pipelines in case major leaks or breaches occur. Such failures can be provoked by corrosion or external damages. Major causes for externally induced failures are construction works with associated excavations. CO_2 itself is not toxic but can affect the human body when concentrations reach 6 to 7%. Concentrations of 10% and more are usually lethal [Gale and Davison 2002]. Due to the density of CO_2 larger than the density of air, it can accumulate in depressions, imposing a risk for human and animal life. The selection of the pathways of a CO_2 pipeline outside of depressions and valley but along topographical exposed positions with higher ventilation can reduce the risk of CO_2 accumulation. Comparable to methane CO_2 is a colourless and odourless gas and thus can not be sensed in time by humans. The addition of strongly scenting trace gases in the gas stream would increase the safety as it is done in natural gas pipelines.

Due to the fact hat CO_2 is inflammable, the risks arising from CO_2 leaking from a pipeline would be much lower than the risk of natural gas leakages. Simulations have shown that leaking CO_2 from a buried pipeline moves mainly vertically upward and is dispersed quickly [see Hendriks et al 2003].

Another implementation problem for CO_2 pipelines is the corrosion prevention. The corrosion can be caused by the presence of H_2O in CO_2 which generates corrosive acid H_2CO_3. Therefore, it is important to transport CO_2 in dry condition which is achieved by the dehydration after the initial compression.

Measures for the minimisation of risks could be:

- Safety zones along both sides of the pipelines (distances to buildings),
- Increased wall thickness or pipelines in inhabited areas,
- Reduced distance of safety valves in inhabited areas,
- Suitable above ground marking of the pipeline to prevent damages resulting from construction works
- Monitoring of the pipeline.

All together, the risk of failure of CO_2 pipelines is considered lower as the risk associated with pipelines for hazardous liquids. Compared to natural gas, the occurrence of failures is considered to be in the same level but with significantly less harming consequences [Gale and Davison 2002].

3.7.2 CO_2 transportation in ships

There are only a few examples for the CO_2 transportation via tankers. As mentioned earlier this option is suitable for offshore geological CO_2 storage and is feasible for longer distances [Heddle et al. 2003]. One of the possibilities to use CO_2-tankers is the transportation of CO_2 from the onshore harbour with a small storage facility to the underground geological storage site located offshore. There, CO_2 could be injected into the underground well via a vertical pipeline. Ships would most probably come into play to supply enhanced oil recovery project with CO_2.

At least two companies are transporting CO_2 in small scale by use of ships: AGA/Linde GAS in Germany and Hydro Gas & Chemicals in Norway which has been transporting CO_2 since 1989. The tank vessels have the capacities of 1,250 tonnes and of 850-1,400 tonnes, respectively. The tankers are designed for transporting CO_2 at 1.4 to 1.7 Mpa and at the temperature -25 to -30 °C [Odenberger and Svensson, 2003].

In ships of CO_2 is usually transported in cold liquid phase. This state is preferred to the supercritical phase because the required pressure in the tank compartments would make necessary unacceptable wall thicknesses. Depending on the size of the individual tanks the necessary wall thickness could even exceed the material quality that could be welded.

For the transportation of CO_2 to the amount captured at the Hypogen plant special ships would have to be built. The design most probably could be similar to the ships transporting LNG and there have been already studies performed in this direction [de Koijer, 2004]. The transportation of CO_2 by sea makes necessary the construction of temporary storage facilities at the points of loading and at the injection points depending on the rate of injection into the storage well. As from the legal situation of CO_2 storage only enhanced oil recovery could be imagined in the offshore area it has to be assumed that a storage facility will be required. Injection into a saline aquifer would require unloading the CO_2 at the onshore location to stay in compliance with the OSPAR convention.

Similar to the situation with pipeline transportation it is difficult to give accurate cost figures for CO_2 transportation in ships. Based on Odenberger and Svensson (2003), some estimates have been made. It can not be judged whether the figures given in Table 3.15 are coherent with the results of de Koijer (2004), as there are only few details given in the latter reference.

Table 3.15 - Cost estimates for ship transportation of CO2 based on Odenberger and Svensson (2003)

	Ship transport Cost per tonne
€/100 km	1,3
€/200 km	1,4
€/300 km	1,5
€/500 km	1,7
€/1000 km	2,2

Conclusions for the Hypogen programme

The choice of the transportation system for the CO_2 will largely depend on the site chosen for the facility and the site chosen for storage. The existing information indicates that there are no technical obstacles that could put the whole transportation system at risk. It might happen however that the transportation costs will impose significant difficulties to the economy of the project. The permitting process for pipeline construction could be very time consuming, a fact, which endangers the overall time schedule of the Hypogen project. Using other means of on land transport such as railway transportation will most probably be prohibitively expensive.

3.8 *Storage of CO_2*

3.8.1 Introduction

There are several options actually under discussion for the storage of CO_2 outside the climate system. Generally one could distinguish between storage in the water column of the oceans, storage in geologic formations, storage by mineralization and storage by fixation in organic matter. Each of the four approaches can again be divided into a number of variants. The further analysis will be limited to the variants of storage in geologic formations. This limitation should in no way imply that the other approaches are not feasible or could not contribute to the storage of CO_2 in the future.

Table 3.16 - Storage options for CO_2

General approaches for the storage of CO_2 outside the atmosphere			
Storage in the water column of the oceans	Storage in geologic formations	Storage by mineralization	Storage be fixation in organic matter

The reasons for the exclusion of storage in the water column of the ocean, of storage by mineralization and storage by fixation in organic matter are the following:

Although storage in the ocean has attracted a lot of attention in several countries and there have been numerous research projects exploring this option it still seems hard to realise. The opposition of stakeholders, especially of environmental groups against storage in the ocean waters is very high. There are strong misgivings that the introduction of large amounts of CO_2 could have adverse effects to the biosphere in the oceans. Further the durability of storage in the oceans is doubted. The strong objections of politically influential groups against storage in the open ocean have motivated the industrial stakeholders of CO_2-storage in Europe not to pursue this option any further. This study should not draw any conclusions on the validity of the arguments against ocean storage or on the appropriateness of the industries' decision not to pursue this option. For the Hypogen Programme however it can be concluded that ocean storage will not be a solution, as the key industrial partners are not supporting this approach.

The options mineralization[3] and storage by fixation in organic matter are still on the level of basic research. The size of the tests has not even reached amount of CO_2 that would be exhausted from a pilot scale facility. Being still at an early stage of research, it cannot be assumed that these approaches will be proven at a large scale in due time for the needs of the Hypogen programme.

3.8.2 Storage of CO_2 in geologic formations

The storage of CO_2 in geologic formations can be realised in a large number of variants. Most important are the storage in oil and gas fields, the storage in aquifers and the storage in coal seems. Further there are options like the storage in abandoned mines or in salt caverns (see Table 3.17). Among the variants listed in Table 3.14, storage in oil and gas fields and storage in aquifers will be analyzed in detail. The other options are judged as not promising for the targets of the Hypogen Programme and thus presented only in brief.

Storage in coal seems is a technically feasible option because CO_2 has a high affinity to be adsorbed to coal, which normally is at least partly adsorbed with methane. Among these two molecules, CO_2 has a greater affinity. By consequence, if entered into a coal seem, CO_2 replaces the present methane. In molecular terms, coal seems can adsorb at least twice as much CO2 as methane. So, if any methane released from the coal seems was burned, there was still a reduction of overall CO_2

[3] An overview on the research on mineralization can be found e.g. in Hujigens and Comans (2003)

emissions into the atmosphere of at least 50 %. It should be noted though that in terms of global warming potential, the balance might change drastically towards lower emissions reductions or even a net increase of emissions, if only part of the released methane was burned. This change in balance is due to the high global warming potential of methane (being set to 21 until the end of the first commitment period).

In the summary report to the GESTCO project [Christensen and Holloway, 2003] a brief summary about the situation of CO_2 storage in coal seems is given. Several questions and obstacles to this option are lined out. According to the report, this technology is still at an early stage of development leaving large room for uncertainty. The injection of CO_2 depends on the presence of sufficient permeability of the seems. However, according to the GESTCO summary report, the in situ permeability of the Carboniferous coals seems found in Europe were thought to be generally low and possibly too low.

For the storage of CO_2 in abandoned coal mines varying theoretical potentials are reported in the European area by the GESTCO report. On the one hand, this seems to be viable option for mines in Belgium. On the other hand, the abundant evidence for leakage in the UK and in Germany prevents the use of mines for CO_2 storage there. Although the principal feasibility of CO_2 storage in abandoned salt mines seems to be quite certain, these will probably be reserved for other purposes generating a higher benefit.

Table 3.17 - Storage of CO_2 in geologic formations

Main variant	Options	Onshore	Offshore
Storage in oil and gas fields	Depleted oil and gas fields	x	(x)
	Enhanced oil or gas recovery	(x)	x
Storage in aquifers	Low temperature aquifers	x	x
	Geothermal aquifers	x	x
Storage in coal seems	Enhanced coalbed methane production	x	-
	Storage in unminable coal seems	x	(x)
Storage in salt caverns		x	-
Storage in abandoned mines		x	-

3.8.3 Storage in oil and gas fields

The storage of CO_2 in oil and gas fields has to be generally separated into storage in depleted reservoirs and into storage by enhanced recovery of hydrocarbons. Both options principally use the pore volume that previously had been filled with hydrocarbons or is to be depleted from hydrocarbons at the very moment of storage. These options make use of generally well explored geologic structures, since the production of oil and gas usually requires intensive and systematic exploration. Further, the presence of oil and gas that had remained in the reservoir over geologic time scales indicates that the structures are fully confined by sealing layers. Due to the hydrocarbon production activity there is usually a fully developed infrastructure that could theoretically be used at least in part for the CO_2 storage operations.

The storage in depleted gas fields is assumed to be fairly possible due to the field behaviour of at least some of the major gas fields in the southern North Sea reservoirs. These are of the so called "depletion drive type" [Christensen and Holloway, 2003]. The term depletion drive describes the process of production of gas from a reservoir with a pressure much higher than atmospheric pressure. The pressure difference leads to a spontaneous flow of gas through the production wells without any pumping efforts ("depletion drive"). Although the reservoir pressure is reduced by the withdrawal of gas, the inflow of water into the pore spaces is very small in many fields. This situation is described as that there is "low water drive" [Christensen and Holloway, 2003]. The reduction of reservoir pressure leads to some compaction of the rock matrix, which usually is quite limited. The observations about water inflow and compaction lead to the assumption that in many cases up to the same volumetric amount of CO_2 can be entered into a depleted reservoir as the previous gas production. Table 3.18 shows the storage potentials given by Christensen and Holloway (2003). This storage potential gives the maximum best estimate at the actual state of exploration. The estimations clearly reveal that in all the analysed countries apart from Greece, there would be ample potential in oil and gas reservoirs for the storage of the CO_2 captured from a demonstration facility.

The advantages of oil and gas reservoirs for CO_2 storage could be summed up as follows:

- The hydrocarbon reservoirs have proved their capability to retain fluids for long periods of time;
- Intensive exploration activity has produced a sound knowledge of the geology of the reservoirs;
- existing infrastructure might be used for the storage activities;
- depleted gas fields have already been used for temporal storage of gas and thus proven the suitability for storage.

Table 3.18 - Maximum potential CO_2 storage capacity of oil and gas fields of selected European countries (data from: Christensen and Holloway, 2003)

Country	Oil fields (mill. tons of CO2)	Gas fields (mill. tons of CO2)	Total storage capacity (mill. tons of CO2)
Denmark	176	452	628
Germany	103	2227	2330
Greece	17	0	17
Netherlands	54	10907	10961
Norway	3453	9156	12609
UK	3005	7451	10456
Total of explored area	6808	30193	37001

3.8.4 CO_2 storage in context with enhanced hydrocarbon recovery

CO_2 could not only be stored in depleted hydrocarbon reservoirs but is also used for the improvement of production of operational oil fields today. The background for these so called enhanced oil recovery (EOR) activities is the objective to increase the overall production and the production rate of existing oil fields. Usually only a fraction of the overall oil in place in a field is produced with the remainder staying in place. For this remaining oil it would not be economically attractive to undertake further measures to allow its production. The actual fraction recovered depends strongly on the specific reservoir geology and behaviour as well as on the oil market situation during production. As a rule of thumb, it could be said that in average one third of the oil in place is produced with two third staying in the field[4]. With decreasing production rate of a field during the time of its development, the producer can undertake measures to increase productivity or to at least slow down the production decrease. Next to secondary production[5], measures for tertiary production can be undertaken, which aim at reducing the viscosity of the oil in the reservoir with simultaneous pressure increase. One way achieving this is the injection of CO_2which is easily dissolved in oil with medium to low density. The dissolution of CO_2 in the crude oil causes it to

[4] This value is given e.g. by Peteves and Tzimas (2003)
[5] Secondary production usually means increase of reservoir pressure by water injection

swell and reduces its viscosity. Together with the pressure increase resulting from the mass injection of CO_2 an increase of production rate can be achieved. This process is widely used in oil fields in Texas, which are supplied with CO_2 from natural sources. The CO_2 is transported in a long-distance pipeline network. These pipelines allowed the greatest gain in experience with CO_2 pipelines. In today's enhanced oil recovery projects with CO_2 injection the operators try to minimise the mass of CO_2 required as it's a comparatively costly product. [6] This is in a way contrasting the overall objective of CO_2 storage to introduce as much CO_2 as possible into an environment outside the atmosphere.

The economic viability of enhanced oil recovery with CO_2 flooding is limited to the cases where CO2 is available at low costs. This is the case for the West-Texas fields where CO_2 from natural sources is available or at the Weyburn field, where CO_2 can be made available from the North Dakota Gasification Plant. Different to situation in the United States, almost the entire European oil production is located offshore. Enhanced oil recovery activities would be more costly simply resulting from the larger spatial extent of production units and the entire higher costs of offshore operations. Further there are no low cost industrial CO_2 sources available in the closer vicinity of the North Sea oil fields, nor is there an infrastructure for CO_2 transport. At the given time the economic situation can be described as follows: the oil industry seeks to buy CO_2 for EOR activities[7]. The existing actual capture and transport cost are still at a level that exceeds the CO_2 price being offered by the oil industry. Of course the influence of the assumed oil price behind the results of the economic evaluations of EOR projects should not be neglected. Actually the long term oil price projections of the industry are still below US$ 20 per bbl. This is strongly contrasting to the real prices encountered during the first three quarters of the year 2004 being in the order of US $ 40 to 50. As long as the oil industry will not revise its long term projections on the oil price, the economics of CO_2 EOR will remain difficult. On the other side, it could be worth investigating whether the oil price risk might be hedged for EOR operations.

Another important issue for the operation of EOR is the temporal restriction in connection to the field development in the North Sea. A large number of fields whose development had been started in the 1970ies are approaching the end of economic production with primary and secondary production methods. The oil industry does not maintain the production installations after the end of (economic) production. So, the offshore installations will be dismantled and the wells will be closed if there is no prospect for further economic production at a field within a short time period. For the chances for realisation of CO_2 EOR this connotes that there is a rather narrow time window of possibly ten years to the future. After that time, a larger number of fields might be closed. Of course, the production could be started over from scratch. For a new start however it has to be assumed that the costs would be higher than in case of a transition with the use of existing infrastructure and wells.

3.8.5 Saline Aquifer CO_2 Storage

From the theoretical potential, saline aquifers are the prospectively largest sink for CO_2 captured from power stations. The principle is comparatively simple. Storage in saline aquifers is performed by introducing supercritical CO_2 into a well that reaches into a deep saline aquifer with a sufficiently high permeability. The well is designed with an appropriate filter distance in order to allow the CO_2 to flow into the aquifer at the required rate. The storage in saline aquifers should be done with the CO_2 in a dense, supercritical phase in order to use the available pore space most efficiently and at low costs. By consequence, the storage reservoir should be located at depth at least beneath 1000 m to guarantee for a sufficient reservoir pressure. On the other hand the reservoir

[6] Peteves and Tzimas (2003) refer to this point.
[7] Statoil states a demand of 5 mill. tons of CO2 per year over a period of 10 years for the Gulfaks field. The investigated project would be financially viable up to a CO2 price of 11 Euro per ton (Berger, 2004).

formation should not be located at too large depths as there, the drilling costs would be prohibitively high.

The large scale storage of CO_2 in saline aquifers has been carried out commercially in the SACS project at the Sleipner field since 1996. It involves the production of natural gas with a CO_2 content being to high to market the untreated gas. In order to obtain sufficiently low CO_2 concentrations, the CO_2 is extracted in amine separation plants. The SACS project involves the storage of the CO_2 in an aquifer above the reservoir structure[8]. The main economic drive behind the SACS project is a Norwegian taxation regulation, imposing a CO_2 tax on the offshore gas production of NOK 325 per ton[9].

The In Salah gas project has taken up operations in Algeria during summer 2004. There as well a CO_2-rich natural gas is treated to reach commercial concentrations of CO_2. After the separation in an amine plant, the CO_2 is stored in the gas containing reservoir structure. Using the same structure for production and storage of course involves the risk of a breakthrough of CO_2 into the production wells. The operating companies addressed this risk with a careful design of the injection wells that was derived from extensive reservoir modelling works. The design has been chosen as such that it should prevent the breakthrough to occur before the end of gas production.

Three processes are responsible for the containment of the CO_2 in the aquifer after injection into it. First of all the supercritical CO_2 will be kept in place by simple trapping in a permeable structure sealed with dense caprock. The mass injection into the aquifer causes a pressure increase, resulting in a compression of the rock matrix as well as in compression of the brine in the aquifer. On top of the compression of the matrix and the brine, the injection of the CO_2 will cause a lateral displacement of the brine. These processes create the space for the additional mass storage in the aquifer. As trapping is governing the storage in the initial phase of storage in an aquifer, the integrity of the sealing caprock is of crucial importance.

Further processes occurring with the storage of CO_2 in aquifers are the dissolution of CO_2 in the brine and chemical interactions of the CO_2 with the rock matrix that can lead to mineralization. Tzimas and Peteves (2003) state that the importance of dissolution and mineralization among the storage processes are still rather unclear. However, recently presented modelling results suggest a high rate of dissolution of CO_2 into the brine on a long time scale [Buller et al., 2004]. The model results for the SACS project indicate that the dissolution of supercritical CO_2 into the brine increases its density. The density increase leads to a downward flow of the CO_2 rich brine within the aquifer. This process normally should reduce the risk of leakage as it is creating a momentum away from any upward leading pathways.

Mineralization leads to the strongest fixation of the CO_2 in the aquifer. Whether and at which reaction rate it occurs depends on the specific geochemical situation. It should be noted that mineralization of CO_2 is considered as desirable since it leads to a strong fixation but could have adverse effects, too. The mineralization processes usually go hand in hand with dissolution of other parts of the rock matrix. So mineralization could lead to an increased concentration of hazardous trace elements in the brine that formerly were bound to the rock matrix.

3.8.6 Storage costs

There is a large number of estimations for the storage costs of CO_2. One of the more recently published analyses can be found in the summary report to the GESTCO-project [Christensen and Holloway, 2003]. The estimations base on a Monte Carlo analysis. The range of costs obtained in

[8] The Utsira sand stone, a formation with very good permeability is used storage structure. A description of the SACS project and the In Salah project can be found e.g. in Buller et al., 2004

[9] NOK 325 corresponds roughly to € 40. The tax rate is for the year 2004. According to the Ministry of finance, the rate may be subject to changes every year (Norwegian Ministry of Finances, 2004)

this work for storage goes from minimum value of € 0.3 per ton of CO_2 up to a maximum value of € 37.7 per ton with a mean of € 3.1 per ton[10]. Compared to the estimations for the additional cost for the capture processes in the Hypogen facility, these values are low.

As CO_2 is principally a marketable product in the hydrocarbon industries, the economically most attractive solution for storage would be certainly an EOR or EGR project. So, the storage process of CO_2 in connection with EOR could generate a stream of income for the Hypogen programme. On the techno-economical side the core problem to resolve for this solution, is to provide for a transport solution at lower specific cost than the price obtained for EOR. Taking the abovementioned example of the Gulfaks field, the transport costs would have to be lower than € 11/ton of CO_2 in order to create a net income from the CO_2 at the point of the Hypogen facility. But even though, if the transport costs were higher than € 11/ton of CO_2, the EOR solution could be economically more attractive than a simple storage solution. This depends on the transport and on the storage cost of the alternative solution without EOR. The actual economics of carbon capture and storage would make necessary a financial contribution resulting from the sales of CO_2 as a product though.

3.8.7 Purity requirements for the CO_2 for storage

The general discussion on the capture and storage often assumes the existence of a pure gas stream of CO_2. As the CO_2 will be produced in a large-scale industrial process, this assumption does not hold true. Instead there will be impurities within the gas stream. These – depending on their nature – could have a major impact on the characteristics of the gas stream and by consequence also has implications on the legal situation and public perception of projects creating, transporting and storing such gases.

One of the side components that could possibly occur in the CO_2 stream captured from the plant is hydrogen sulphide (H_2S). The occurrence in the gasification process is quite likely, as most of the coal qualities existing worldwide contain sulphur, which is converted into H_2S during gasification. Hydrogen sulphide is an extremely poisonous, moderately corrosive gas. Hence, already with a minimal share of hydrogen sulphide, the characterisation of the (CO_2) gas stream as being non-toxic, non-hazardous wouldn't hold true any more.

The permitting requirements for the handling and storage of a toxic gas would most probably be drastically higher if being permissible at all. The public perception of an activity producing large amounts of toxic gas and storing it underground would most certainly be extremely negative. With respect to the rationale of the Hypogen programme, it would be therefore definitely advisable to avoid any side components in the captured gas stream that could change the characteristics of CO_2 as being non-toxic, non-hazardous and non-corrosive. Any other composition would put the feasibility of the Hypogen programme at risk due to legal barriers or public objections.

3.8.8 Conclusions for CO_2 storage

Among the wide variety of options for carbon capture and storage three solutions seem to be most promising:

- Storage in connection with EOR activity,
- Storage in a depleted gas field,
- Storage in a saline aquifer.

Storage in connection with EOR offers the possibility to improve the economics of the carbon capture and storage. Although the value of CO2 for EOR is limited still, this option should not be underestimated, as a future rise in oil price would increase the value significantly. The problems arising from the low oil price assumptions used in the actual assessments of EOR activities could be

[10] p5 is given with € 0.7/t and p95 is given with € 10.6/ton.

avoided with risk sharing contracts. These contracts would link the price paid for CO_2 to the spot market price for oil. With such a risk-sharing contract, the operator of the Hypogen facility would participate in the profits of high oil prices. The risk of low oil prices could be partially hedged with forward contracts. These of course would have only a limited duration that is much shorter than the ideal contracting time for a CO_2 supply for EOR. There are no active EOR operations with CO_2 flooding in the North Sea at the point of time when this study was elaborated yet. However stakeholders from the oil industries expressed that there are plans for starting such operations in the close future. So there are good chances that some first CO_2 EOR projects have started operation by 2006/2007.

Principally also the production of natural gas can be improved by the injection of CO_2. This would be then one option of enhanced gas recovery. In the discussions with the industry stakeholders, it seemed however that the interest was more focussed to EOR operations in the mid term future. So, although there could be opportunities for onshore EGR projects with CO_2, there seems to be higher interest in the EOR route.

The EOR solution does have further advantages as it uses geologic reservoirs that are already very well explored, that have proven to be confined for a very long time in the past and which are not suitable for other uses due to the content of hydrocarbons. The high margin of geological safety resulting from "proven reservoirs" is partially reduced due to the prior activity hydrocarbon-extraction. The exploration wells, the production wells and possibly other injection wells for water or steam injection into the reservoir constitute possible pathways for CO_2 leakage. This risk of leakage could be managed though as the oil and gas industry preserves sufficient records of the offshore fields. The knowledge of the existence and location of these wells allows to assess the risk of leakage for each of it individually and to approach it with geotechnical methods. These could be measures such as an additional sealing with elastic and acid resistant cements. The geotechnical safety of man made pathways is one of the risks that might need further research.

Form a resource economic point of view, the EOR pathway for the Hypogen programme would offer a further advantage. The advancement of EOR in the European oil fields of the North Sea would improve the security of supply. This improvement would occur irrespective of the fuel used for the electricity and hydrogen generation in the Hypogen facility. As discussed already above, there is only a limited time window for the realisation of EOR measures. The Hypogen programme could be part of a strategy that enables the European oil industry to make benefit of this window of opportunity.

The storage in depleted gas fields also offers a set of advantages. Comparable to the EOR-option this solution would also make use of well explored and well understood geologic structures. The gas fields have proven to be sealed as well. The third parallel is the question of geotechnical safety that had to be addressed carefully. Different to the EOR option, the storage in depleted gas fields would not offer the chance to generate a stream of income. This disadvantage might possibly be outweighed by the possibility to locate the Hypogen facility directly at the storage site. There are many gas fields in the Netherlands and in Northern Germany that are reaching the end of production in the nearer future. Thus there are possible onshore sites for storage in depleted gas fields. EOR with CO_2 flooding has not been discussed for any of the few and small onshore oil fields in Europe.

Saline aquifers are the most abundant structure that could be used for storage of CO_2. So, if locating the Hypogen facility will be governed by a number of strongly restricted parameters such as fuel transport, electricity grid connection, local hydrogen demand, public perception, the storage in a saline aquifer might be the most viable option. The degree of exploration of possibly suitable aquifers differs vastly all over Europe. Therefore the exploration requirements and the risk that an intended aquifer structure might prove as not suitable have to be weighed when developing the Hypogen facility. As aquifers are widely distributed and offer a high theoretical potential for storage, the Hypogen programme could improve the overall prospects of carbon capture and storage by adding another real life proof of feasibility to this option.

3.9 Summary and conclusions for Hypogen

- Several technology options exist for Hypogen, mainly depending on the solutions adopted for:
  - hydrogen production (fuel and process);
  - electricity production (thermal cycle);
  - CO_2 capture and storage.
- Hydrocarbons, especially natural gas, are the dominant source of hydrogen today in refining and other industrial applications and are generally the lowest cost current option. Different processes are employed (steam reforming, autothermal reforming, partial oxidation) and their technology are commercially mature.
- The production of hydrogen from coal can use a variety of gasification processes (fixed bed, fluidised bed, entrained flow). Also in this case the technology is mature, but the system is more complex and the cost of hydrogen produced is higher than using natural gas.
- Under the current trends of the energy market, hydrogen production from hydrocarbons will be more competitive than hydrogen produced by coal gasification also in the medium term. The deployment of CO_2 capture and storage on this plant will increase the cost of hydrogen by 15-20%, but will not modify this situation. However, in the selection of the fuel to be used in Hypogen other factors, such as the security of cost efficient supply in the future will be an important issue.
- Among the option for CO_2 capture (post combustion, pre combustion, oxyfuel combustion), the pre combustion capture is the only way where hydrogen, or hydrogen rich gas, should be produced. As the CO_2 concentration is relatively high (about 30%), it can be separated using a physical absorbent, with a process less energy intensive than chemical solvents used in post combustion capture.
- The choice of the transportation system for the CO_2 will largely depend on the site chosen for the facility and the site chosen for storage. The existing information indicates that there are no technical obstacles that could put the whole transportation system at risk. It might happen however that the transportation costs will impose significant difficulties to the economy of the project. The permitting process for pipeline construction could be very time consuming, a fact, which could endanger the time schedule of a Hypogen project.
- The feasibility of permanent storage of CO_2 is critical to the success of the de-carbonisation approach and represents a high risk associated with the success of Hypogen. Among the several options actually under discussion, the storage in geological formations, and in particular the storage in oil and gas fields and the storage in aquifers, seems the most promising solution for Hypogen. In particular, storage in connection with enhanced hydrocarbons recovery (EOR) offers the possibility to improve the economics of the carbon capture and storage.
- A part of hydrogen, or hydrogen rich gas, produced in Hypogen is utilized for power generation. The combined cycle is the most advanced and efficient solution. The integration of the production of hydrogen rich gas from coal and heavy oils (syngas) with a combined cycle, without CO_2 capture, is already used in existing plant (Integrated Gasification Combined Cycle, IGCC), with an electrical efficiency ranging between 40 and 42% and very low emissions of pollutants such as sulphur dioxide. The integration of this plant with pre combustion CO_2 capture is the most promising solution for the production of de-carbonised electricity from coal in the medium-long term. To make this technology widely competitive in the electricity market

large efforts are needed to: i) increase plant efficiency; ii) reduce capital cost; iii) improve reliability and operating flexibility.

- The other option for the plant is the integration of CO_2 capture and combined cycle with production of hydrogen from natural gas. This solution, completely new in the field of power generation, can rely on commercial technologies and lead to a system with higher efficiency. Therefore gas based hydrogen might be the better choice if the tight time schedule for a Hypogen facility should be kept.
- The deployment of pre combustion CO_2 capture on a combined cycle plant, as planned in Hypogen,
  - will increase the investment cost (by 30-40% for IGCC systems and 70-80% for natural gas systems) and the cost of electricity (by 30-40%), with a reduction of plant efficiency of about 6-12 points;
  - requires a proper integration of the hydrogen production section (gasification or reforming), gas clean-up and thermal cycle;
  - involves the utilization in thermal cycles of a gas with different characteristics and requires some changes and optimisations in the power plant; in particular, the availability of high efficiency gas turbines able to operate with hydrogen rich gas is a key issue.

4. ANALYSIS OF THE SOCIAL AND ECONOMICAL ENVIRONMENT

The development of de-carbonisation of fossil fuels for electricity and hydrogen production in a liberalised energy market requires, besides the availability of suitable technologies, a framework that promotes the investments in these environmentally compatible energy systems, making their higher costs affordable under market conditions. The creation of this favourable framework largely depends on the promotion of measures for the reduction of greenhouse gas emissions (like the emission trading mechanism); these, in turn, affect the development of a hydrogen market for stationary and transport applications. Moreover, this framework requires that all the barriers related to CO_2 storage (e.g. legal and regulatory aspects, public acceptance) will be overcome.

The development of this framework in next years is of primary importance for the implementation of a full scale demonstration project, like Hypogen, and for the involvement of industrial partners.

4.1 The impact of the European Emissions Trade Scheme on the Economics of Hypogen

The European Emissions Trade Scheme (ETS) is one of the European Union's policy measures addressing the climate change problem and the Union's as well as the Member States' requirements to fulfil the Kyoto targets. The ETS (EU, 2003a) is a market-based policy approach to regulating industry's greenhouse gas emissions. It is set up as a so called "cap and trade" system. There is a principal difference to the setting of fixed emissions standards for industries in quantitative terms as is the case for materials that cause air pollution. The industries subject to the ETS are allocated emissions allowances that give the permission to emit a set quantity of greenhouse gases. By allocating a specific quantity, the "cap" is set to the operators of the facilities. The emissions allowances are tradable, allowing the operators of efficient installations to sell unused allowances. Operators of installations with less efficient installations can invest in efficiency improvements or other measures for the reductions of greenhouse gas emissions. This could be for example a fuel switch to a fuel with lower carbon intensity. The other option is to buy emissions allowances up to the necessary demand from market participants with efficient installations or from those who are able to invest in cost efficient emissions reduction measures. The economic principle behind this cap and trade system is to use market mechanisms to achieve the overall cost optimal way for emissions reductions in the European Union's industries. Due to the ETS, emissions reductions will generate a value in the carbon-intensive industries.

The time frame for the ETS is set as follows:

- setting of the first National allocation plans before end 2004,
- first trade period from 2005 to 2007,
- second period from 2008-2012, with the following periods to be consistent with the commitment periods under the UNFCCC, the Kyoto-Protocol and following protocols.

The ETS is linked to the Emissions Trade under the Kyoto Protocol in several ways. It should be noted though, that the establishment of the ETS is not linked to the ratification of the Kyoto Protocol. So far, the European Union's policy is dedicated to fulfil the Kyoto targets irrespective of the formal status of the Protocol. This in turn sets one of the links from the ETS to the emissions trade under the Kyoto-Protocol, which could be seen as the paradigm for the ETS. The Emissions trade under the Protocol is also a cap and trade system. Here, the cap is set for the Annex I countries of the UNFCCC and trading will take place among the national governments of the Annex I countries[11]. The states are holders of allowances under the Kyoto Protocol, but other legal entities are also entitled to hold allowances. The Kyoto Protocol and the Marrakech Accords also foresee the generation of Verified Emissions Reductions (VER) from the Joint Implementation (JI)[12] and Certified Emissions Reductions (CER) from the Clean Development Mechanism (CDM)[13] which can be held by states or by other legal entities. These three "emission rights" refer to the Kyoto Protocol and are not directly transferable into allowances under the ETS.

For trading among industrial companies under ETS, allowances from the Kyoto Protocol are transferred in parallel among the national accounts, when cross border trade takes place in the Union. So, market activities of the ETS also influence the national accounts of allowances. The ETS also foresees the integration of CERs and VERs. As a consequence, these emission rights generated under the Kyoto Protocol will influence the market under the ETS. If the CDM proves to be successful and generates a large amount of CERs at competitive costs, companies subject to the ETS will probably make use of the CERs. In doing so, they could fulfil the ETS requirements even if the allocated allowances are not sufficient to match their emissions. The draft directive on linking the ETS with the project based mechanisms (EU, 2003b) foresees a limit of 6 % of the initially allocated amount for the accountability of CERs and VERs. This limitation may be raised to 8 % after review by the Commission. On the one hand, it could be judged that the influence of maximally 6 % to 8 % of "external" emission rights should be limited. On the other, it could be the case that these emission rights play an important role for the level of the marginal prices within the ETS. The influence on the marginal prices depends strongly on the shape of the integrated cost function for emission reduction measures in the industries subject to the ETS. Research and modelling attempts have been made for this cost function, but uncertainty remains very large [e.g. Hendriks et al 2001 or de Beer et al 2001].

Not only the project-based mechanisms, but also the national allocation plans, under which the industry is supplied with the allowances, play an important role within the ETS. The allocation of emissions allowances falls under the jurisdiction of the member states, as the fulfilment of the Kyoto obligations is ultimately a national responsibility. The ETS directive foresees an allocation by grandfathering as the main method for the time up to 2012. Grandfathering basically means that the existing installations will be awarded emissions allowances at no cost. Besides grandfathering, the national governments may auction up to 5 % of the total allocated amount for the first period and up to 10 % for the period from 2008 to 2012. It is up to the national allocation plans to reserve emissions allowances for a no-cost distribution to new market entrants. Alternatively, the allocation plans may foresee that new market entrants have to purchase the allowances needed on the market. The allocation methods of the various national plans also differ significantly. There are allocation procedures based on industry average benchmarks and others based on existing actual emissions of some base period. Further the plans include varying fulfilment (or reduction) factors by which the allocated amount is reduced from the benchmark or historic value. These are introduced to produce a net reduction in emissions of the respective national industry facilities that contribute to the national emissions reduction target. It has been shown, however, that the fulfilment factors chosen are very close to one, enforcing only minor reductions. Some allocation plans such as, e.g. the German allocation plan,[14] foresaw regulations for the time after 2007 by setting fulfilment factors for a longer time period. These elements reaching beyond the first ETS period were not accepted by the EU-Commission as there is a strong desire there for harmonisation. Such harmonisation policies for future periods could be hampered if the national plans set regulations beforehand.

11 Of course, the trade can be delegated to other public or private institutions

12 Joint Implementation, a way to earn credits by investing in emission reduction projects in developed countries that have take on a Kyoto target

13 The Clean Development Mechanism, a way to earn credits by investing in emission reduction in developing countries

14 The German national allocation plan is referred to as the "Zuteilungsgesetz" accessible in German at http://www.bmu.de/files/zuteilungsgesetz_gesetzbeschluss.pdf

The level of the future market prices for emissions reductions is highly speculative. By consequence it is hardly feasible to found the economics of the Hypogen plant on the financial contributions resulting from the emissions reductions. There may be new financial instruments that could overcome part of the risk associated with the emissions trade market. These will be described in the Financial Engineering section. The main sources of uncertainty about future market prices are:

- the Kyoto Protocol has not yet come into force and it is still unclear whether and when this will happen;
- the potential market for CDM-projects is largely unknown. The lack of experience with the qualifying criteria (additionality and baselines) is a major source of uncertainty. Further the transaction costs may strongly influence the size of the CDM-market;
- the post-Kyoto targets for emissions reductions for the Annex I countries have not yet been negotiated;
- there are large emitters among the non-Annex I countries, China as the second overall largest emitter is the most prominent example. It is not known whether non-Annex I countries will adopt emissions targets in the period starting 2013 or at which later date this will happen. Nor is it known what level these targets will have;
- the future sectoral distribution of emissions reduction requirements in the European Union is not known;
- the cost functions for emissions reductions are not known in industry or the other sectors.

From the amount of uncertainty about the governing influential factors for the future market prices of emissions reductions, it could be concluded that it does not make sense to develop an autonomous price forecast for emissions reductions. Even if a forecast were made, this would hardly add to the economic projections. The discussions with stakeholders during the preparation of this study revealed that it was virtually impossible to make emissions reductions bankable at the moment.

4.2 Legal and regulatory aspects of carbon capture and storage

The analysis of the legal aspects of carbon capture and storage could be divided into three fields as is done with the investigation of the technical aspects. There is the regulatory environment for the construction, operation and the dismantling of an industrial facility. Then there is the regulatory environment for the construction and operation of a transport system for CO_2 and finally the legal and regulatory environment for the storage of CO_2.

When investigating the entire regulatory framework of carbon capture and storage, it becomes quickly evident that the extent of legislation and regulation decreases drastically on the chain from capture to transport to storage.

A Hypogen facility as proposed in this study could be principally appraised as a special type of a power station. As it involves the operation of a gasifier and a syngas cleaning unit, part of it comprises a "chemical plant". For both power stations and chemical plants, there are regulations concerning construction and operation all over Europe. Power stations are widespread, the procedures for permitting may be quite elaborated and time consuming but they can be assumed to exist. Some additional requirements to the permitting process and to the operation of a Hypogen power plant might be expected because it will handle explosive gases, especially hydrogen. Regulation is in place for this as well, as there are abundant examples of hydrogen producing industrial facilities especially in the chemical and in the petrochemical industry. This estimation was generally shared by stakeholders involved in a series of discussions about the Hypogen programme. The permitting of the facility was not seen as a matter of special concern.

The transportation of CO_2 in significant amounts on land would have to be performed in pipelines. The most favourable economic results are reached when transporting supercritical CO_2 at high pressure (above 106 bar) and ambient temperature. So far there are no existing pipelines for the transportation of CO_2 in Europe. However there are examples in the United States. On the other hand, there is an abundance of pipelines for the transportation of high pressured gases, especially natural gas, and for the transportation of liquids such as crude oil or naphtha. The ex ante evaluation of the regulations for the construction and operation of pipelines for CO_2 transportation could thus draw on the legal framework of existing pipelines in Europe and on the experiences with operating CO_2-pipelines in the United States. Furthermore there are examples of pipelines transporting hydrogen (e.g. pipelines operated by Air Liquide in Northern France, Belgium and the Netherlands as well as a pipeline system in the Ruhr area). Hydrogen, which is an explosive and much more fugitive gas than CO_2, imposes a higher risk. There might be some differences in the permitting process concerning safety regulations compared to hydrogen pipelines. Although not an explosive or flammable gas, CO_2 may accumulate in poorly ventilated depressions or subsurface parts of buildings. This is different to hydrogen, which hardly accumulates because of its high volatility. Altogether, the fact that natural gas pipelines and even hydrogen pipelines can receive permitting in central Europe justifies the conclusion that the permitting of CO_2 transporting pipelines will not impose a critical risk to the realisation of a Hypogen facility with CO_2 storage.

For the third step of the process chain, the storage of CO_2, there is no specific regulation in place. Although it has been discussed in the scientific community and by enterprise representatives of CO_2 intensive industries, lawmakers have not concerned themselves with carbon capture and storage so far. This means that existing laws and regulations have to be analysed and interpreted as to how they could be applied to specific CO_2 storage cases. The situation is aggravated as there are hardly any examples for CO_2-storage worldwide. Up to now, there is the Sleipner CO_2-Injection Project of Statoil and, from this year on, the In Salah Gas Project starting in Algeria. These two activities could be judged as more or less true commercial CO_2 storage projects as they are not associated with enhanced gas and oil recovery activities.[15] But even though they are not connected with enhanced production measures, they are connected to hydrocarbon production. As a consequence, their regulation falls under the regime of the respective laws for oil and gas exploitation. There is also the Weyburn field in Canada, where CO_2 from the Dakota Gasification Plant is used for enhanced oil recovery. So here, one can identify the use of CO_2 from a fossil fuel plant, but again within the context of hydrocarbon recovery, not as a simple storage activity.

Besides the Sleipner project, the In Salah project and the Weyburn project, there are many sites, especially in the United States, where CO_2 from natural sources is commercially used for enhanced oil recovery. Even if those projects allow gaining a lot of technical experience, the appropriateness of their regulative element, as an example for CO_2 storage in general, is not given.

Apart from activities where the gases are intended to remain ultimately in a geological formation, there are many subsurface installations for the storage of gas and petroleum products. Generally speaking, there are storage reservoirs in porous media and in caverns. Both types are used to match intertemporal variations of demand and supply and to maintain strategic reserves. The operators of underground gas storage reservoirs have a strong interest in keeping the gas in a small confined area in order to be able to recover it with minimum losses. The long-term storage safety is not an issue as the reservoir content is not meant to remain in place. As a consequence, the regulations for underground gas storage will probably not be directly applicable to CO_2 storage. However the existing safety regulations for daily operations and for the risk of catastrophic failure for these reservoirs might stand as an example for CO_2 storage.

[15] There is a difference between the two with respect to the drivers involved. The Sleipner case is strongly motivated by the Norwegian CO_2 tax for the offshore industry, whereas the In Salah project has no direct financial driver but is mainly driven by the objective to demonstrate CO_2 storage on a commercial scale and to gain experience.

4.2.1 Legal aspects of CO_2-storage

The evaluation of the legal aspects of CO_2-storage should be divided into three sections: on land CO_2 storage in geological formations, CO_2 storage in the ocean and in subsurface formations under the ocean and the implications of the Kyoto-Protocol for CO_2 storage. This division adds to the clarity of the analysis in so far as the permission to store CO_2 on land falls under the legislation of a single state. In contrast to this, the storage in the ocean or in a submarine formation automatically falls within the scope of international law. The assessment of the implications of the Kyoto Protocol should reveal the credibility of CO_2 storage under the Protocol, which has a direct impact on the economic viability of CO_2 storage.

4.2.1.1 Implications of the quality of the stored CO_2

The principle evaluation of the legal aspects of CO_2 usually refers to the gas as being an homogenous, pure substance. In reality, the CO_2 stream delivered from a Hypogen facility for storage will be a technical gas with at least minor impurities. The energy and cost requirements for purification rise exponentially with higher degrees of purity. As a consequence, the operator of the Hypogen facility will be motivated to minimise the efforts for purification. On the other hand, the existence of trace gases derived from the sulphur content of the fuel may create an unacceptable toxicity of the gas stream. Furthermore, any water content in the gas may provoke a strong increase in the risk of corrosion.

For the Hypogen programme it will be important to consider a technical specification such that the CO_2 transported and stored can be judged as a non–toxic and non- or low corrosive gas. Given these classifications, the properties of the CO_2 should not impose a risk to the permitting of transport and storage activities. The processes required to reach these properties will however influence the economics of the facility.

4.2.1.2 Legal aspects of geological CO_2 storage at an on-land location

At first, any CO_2 storage project on land falls under the sovereignty of the state in which the project is located. It has to be kept in mind though, that the supranational law of the European Union is applicable to the investigated case as well. The most prominent of the European directives involved are the framework directives on waste materials (75/442/EEC), the landfill directive on dumping waste materials (91/31/EEC) and the framework directive on water (2000/60/EC).

In the Netherlands, the legal situation of CO_2 storage has been investigated by a task force of lawyers from different ministries (CRUST, 2002). This is one of the only cases, for which an analysis of the legal situation of on-land storage of CO_2 has been investigated. For this reason, the Dutch situation is analysed in more detail. Interestingly, the approach followed by this project foresees only a temporal storage with the explicit intent of recovering the CO_2 for other uses. This might be a valid approach for a Hypogen facility, too.

Unlike most countries in Europe, a newly revised mining legislation has just come into force in the Netherlands that apparently offers more clarity with respect to provisions for the storage of CO_2. The authors of the CRUST-study point out that the Dutch Mining law does not make a differentiation between “buffer storage” and simple “storage”. The latter does not incorporate a later re-use. As a result, it should be possible to assume the validity of the findings of the CRUST-study for both cases even though it focused on temporal storage and a later re-use.

The CRUST-study points out that, from a regulatory point of view, CO_2 is considered a non-hazardous substance or waste. This is quite similar to the situation in the United States, where the Federal regulations classify CO_2 as a "high volatile/ low hazard and low risk" gas. The Dutch legislative appraisal leads to the regulations provided for CO_2 storage or sequestration facilities not being extensively stringent. This holds true for installations above ground or below ground. Further, the safety requirements for such undertakings are at the discretion of the competent authorities.

One main legal question to be answered for underground storage of CO_2 is whether it is to be considered as waste. The Dutch mining law, as analysed by the CRUST task force, refers in this point to the European Framework Directive on Wastes (75/442/EEC, amended by virtue of 91/156/EEC and 91/692/EC) where it is stated that a waste is “any substance or object belonging to the categories referred to in Appendix 1 that the custodian disposes of, intends to dispose of or has to dispose of (Article 1, paragraph a)”. The appendix referred to in the Directive lists sixteen categories of wastes. The last of these categories can comprise virtually any substance. Gaseous effluents such as CO_2 emitted from a stack do not fall under these substances leaving open the question whether supercritical CO_2 would fall under the directive. The CRUST task force concludes that under the European Framework Directive on Wastes, CO_2 intended for storage is to be considered as a waste except when it is emitted into the air. For the Dutch cases, a differentiation is made between the surface installations where the regulations for waste materials do not apply and the subsurface space where waste regulations are applicable. So in the interpretation of the CRUST-study, a compressor would not fall under the regulations for installations handling waste material, but the injection well would do so.

Under Dutch regulations, the above ground installations for CO_2 storage would be subject to the Environmental Management Act. The safety requirements for granting an Environment License are stated to be not fixed. These and the decision about the necessity and the type of a safety assessment are left to the competence of the authorities. For the case of CO_2 storage, the Ministry of Economic Affairs is the competent authority in Netherlands. The above ground parts of CO_2 storage installations generally do not require an Environmental Impact Statement. However there are exceptions for some CO_2-pipeline configurations (i.e. more than 800 mm diameter and more than 40 km of length).

In the Netherlands, the subsurface installations for CO_2 storage would fall under the mining legislation. At the point in time when the CRUST-study was elaborated, not all regulations had been defined under the umbrella of the new mining act of 2003. It was however assumed that the relevant regulations and standards for gas storage would also apply to storage of CO_2.

Even if the interpretation in CRUST (2002) does not persist in a future permitting process for a Hypogen facility, it seems to be quite certain that the European Directive on Wastes will play an important role in the permitting process. All legislation from Member States will have to be coherent with the European Unions regulations. It is hardly conceivable that a new national mining law or a law on handling of waste materials will get round the fact that liquid or supercritical CO_2 is to be considered as a waste.

In general, it can be imagined that three fields of legislation will be touched by any CO_2 storage project:

- waste legislation,
- water legislation,
- mining legislation.

Different national authorities usually represent these three fields of legislation. Because of the lack of precedence, it is not clear which authorities will have to be addressed for a CO_2 storage project. On the side of the authorities, there are probably no procedures on how to handle such requests for permission for the storage of CO_2.

Conclusions for the Hypogen Facility

- Due the absence of any valid precedence of a CO_2 storage project in Europe, the permitting process will break new ground for the applicants, the authorities and also for the courts. The latter will come into play if any official decision is challenged either by the applicants or any third party.
- In most of the countries in Europe – as far as it could be explored for this study - the legislation has not foreseen CO_2 storage in geological formation. The existing laws and regulations do not offer clear rules and limitations for such projects. Instead the existing laws have to be interpreted for their consequences with respect to CO_2 storage. This in turn has two results: first, the time needed for the permitting process will be longer than for other projects of comparable size. Second, the need for interpretation will increase the chances that the official permitting decisions will be challenged at court.
- The time demand and the high probability that the permitting decision will be challenged at court make it a critical issue. This is already the case for the simple procedural risks and does not imply anything about the material issues of the permitting.

4.2.1.3 Legal aspects of CO_2 storage in or beneath the marine water column

The storage of CO_2 in the marine area can be divided into two distinct cases. The first is storage in the open waters of the ocean and the second storage in a geological formation beneath the seabed. The analysis of legal aspects of CO_2 storage in the marine area will concentrate solely on the case of storage in geological formations. Excluding the option in the open waters of the ocean should not preclude that there are no regulations for this case or that it is not permissible in any case. There are however very serious doubts about the environmental impacts and even more about the public acceptance of this option which results in the relevant stakeholders in industry not being ready to pursue this option. Therefore analysing the legal aspects does not promise useful results at the current stage of the process.

Two international conventions are seen as the most important sources of regulations for the storage of CO_2 in the marine environment:

- London Convention with the 1996 Protocol,
- OSPAR-Convention.

Neither of the two conventions makes explicit provisions for the regulation of CO_2 storage. At the time they were negotiated, this technology option has simply not part of the scientific or political agenda yet. As a result the existing regulations of the conventions have to be interpreted as to how they would apply to CO_2 storage. The act of interpretation is not unambiguous. This analysis relies on legal studies not provided for and agreed on by bodies of the conventions, so conclusions presented here may be proven wrong by official findings.

The London Convention refers to activities that could cause pollution of the marine environment. So, if storage in geological formations under the sea were a potential cause of pollution, it could be prohibited by the London Convention. Whereas the London Convention only refers to the sea, the 1996 Protocol to the Convention refers to the sea, seabed and subsoil. The question of whether subsoil only covers the structure directly beneath the seabed, or whether a deeper range of geological formations is covered is still under discussion. When going back to the purpose of the Convention and the Protocol, it could be argued that the space beneath the seabed was also addressed with the general intent to prevent pollution. So any activity that could cause pollution, no matter at which depth beneath the seabed, would be prohibited. It should be noted though that "sub-seabed repositories accessed only from land" are expressively excluded from the Convention and the Protocol. The Convention and the Protocol define the prohibited activity of dumping as activities carried out from vessels, aircraft, platforms or other man-made structures at sea. This definition is interpreted such that pipeline discharges from land based sources without any further installations do not fall under the jurisdiction of the Convention and its Protocol.

For the case of offshore operations which are the majority in the context of hydrocarbon recovery, it is undebated that the re-injection of water and other matter associated with oil and gas production would not fall within the definition of dumping. The London Convention and its Protocol exclude the "placement of matter for a purpose other than the mere disposal thereof, provided that such placement is not contrary to the aims of the Convention [Protocol]"[16].

The OSPAR Convention emphasises the way substances are introduced into the marine environment rather than the effects they have on it. From the definitions and regulations laid down in the OSPAR Convention, it can be concluded that the transportation of CO_2 in pipelines directly from land into a sub sea storage reservoir could be permitted by a contracting party. The reason for this is the definition of land-based sources as "sources with any deliberate disposal under the sea-bed made accessible from land by tunnel, pipeline or other means and sources associated with man-made structures paced in the maritime area under the jurisdiction of a Contracting Party…"[17]. For these land-based sources it says " Point source discharges to the maritime area, and releases into water or air which reach and may affect the maritime area, shall be strictly subject to authorisation or regulation by the competent authorities of the Contracting Parties"[18]. The possibility for Contracting Parties to give permission to such activities is limited however. Purdy and Macrory (2004) point out that the OSPAR Convention obliges Parties to prevent and eliminate pollution from land-based sources. The conclusion is drawn that even if pipeline based storage in the sub seabed were permissible, it may still not be compatible with the OSPAR Convention if it causes pollution.

Offshore activities are largely exempt from the OSPAR convention but only to the extent that it covers the extraction of gaseous and liquid hydrocarbons. The simple transportation of CO_2 to an oil platform with the intent to dispose of the CO_2 without any benefits for the oil production would not be compatible with the OSPAR-convention. The exemption of hydrocarbon recovery would cover enhanced oil recovery or enhanced gas recovery activities but not the storage in aquifers.

4.2.1.4 Implications of the Kyoto Protocol for CO_2 storage

The United Nations Framework Convention on Climate Change (UNFCCC) and the Kyoto Protocol as such have not foreseen CO_2 capture and storage as a means of emissions reduction. The UNFCCC defined emissions as "the release of greenhouse gases and/or their precursors into the atmosphere" (Article 1(4) UNFCCC, 1992). Consequently, CO_2 captured at source and stored outside the atmosphere is not an emission according to the definition in the Convention. Although there is no emission, one could interpret the action of CO_2 capture and storage as an emission reduction. Purdy and Macroy (2004) point out that this distinction is of importance as parties to the Convention were more restricted in how to deal with emissions.

The Convention and the Kyoto Protocol (1997) encourage the protection and increase of sinks and reservoirs, meaning activities removing greenhouse gases from the atmosphere and components of the climate system where greenhouse gases are stored[19]. The definition of emissions as well as the definitions of sinks and reservoirs do not cover the activity of CO_2 capture and storage. However the Protocol calls the Parties to promote the development of "new and renewable forms of energy,

[16] London Convention (1972), Art. III 1(b), London Protocol (1996), Art. 1(4)(2)(2)

[17] OSPAR Convention Art. 1(e)

[18] OSPAR Convention Annex 1 Art 1(1)

[19] Definitions of the UNFCCC: "'Sink' means any process or activity which removes a greenhouse gas , an aerosol or a precursor of a greenhouse gas from the atmosphere" (Art. 1(8)) and "'Reservoir' means a component or components of the climate system where a greenhouse gas or a precursor of a greenhouse gas is stored" (Art. 1(7).

of carbon dioxide sequestration technologies and of advanced and innovative environmentally sound technologies" (Kyoto Protocol, Art. 2(1)(a)(iv)). So in principle, activities such as CO_2 capture and storage should be in agreement with the purpose of the Convention and of the Protocol.

At the given time there is still an obstacle to the credibility of CO_2 capture and storage as a means of emission reduction under the terms of the UNFCCC. The Annex I Parties to the UNFCC have to report their emissions according to the IPCC Guidelines [IPCC; 1997 and IPCC 2000]. These Guidelines stipulate that the calculation of inventories is done by the use of fuel specific emission factors. A reduction of emissions by capture and storage of greenhouse gases prior to the release into the atmosphere is not foreseen. So under the current guidelines, capture activities would not lead to a reduction in emissions accounted in the national inventory. This topic is addressed within the current work on the revisions of the Guidelines [IPCC, 2003]. The aim is to integrate capture activities into the methods for the creation of inventories.

Apart from the accountability of capture activities, regulations have to be developed to deal with emissions during CO_2 transport and the storage process. Further regulations will have to be developed on the monitoring and verification of storage integrity and duration as well as for the accounting of leakage.

4.3 The public perception of Carbon Capture and Storage

4.3.1 Introduction – an overview of existing literature

CO_2 capture and storage in geologic formations represents one of the solutions for the global climate change mitigation. Currently, there has been a lot of research carried out on the improvement of CO_2 capture technology, its economics and cost-effectiveness. However, the policy, regulation and public perceptions of carbon capture and storage (CCS) are of equal importance, since they are interconnected and can represent barriers for the future development of CCS.

The public opinion on CCS has not yet been investigated thoroughly in the European Union, although the research had been conducted in individual countries (UK, Netherlands). The example of the most recent study on public perception of the Tyndall Research Centre shows how public opinion changes when learning more on the subject of CCS [Shackley et al 2004]. Although the survey of public opinion has been conducted with a relatively low number of individuals, the results give an important indication on public perception of CCS. It should be noted that the results obtained in this study cannot be generalised for the total UK population. In the Netherlands more activity is under way, in particular there is an approach to develop a policy strategy that would include clean fossil fuels as part of the solution for the climate change problem, which is reflected in [Lenstra et al 2001] and in [Crust 2002].

The final report prepared for the CO_2 Capture Project presents an overview on the state of policies, regulations and public perception around the world and helps to gain a clearer image on the public perception of CCS in Europe as well [Lee at al 2004]. The work includes a comprehensive survey of existing policies, regulations and incentives, potential barriers for CCS implementation. Moreover, it is stressed that NGOs will play an important role in formation of general public opinion on CO_2 capture and storage.

Another survey of public opinion has been performed recently by Curry at the Massachusetts Institute of Technology [Curry 2004]. In this study a survey of public attitudes towards CCS has been conducted. The respondents formed a representative sample of US population (1200 individuals) and were asked seventeen questions about climate change mitigation, global warming and environment. The results showed that, in general, public has little or no knowledge on CO_2 capture and storage and does not consider global worming as an issue of top priority.

As mentioned earlier, NGOs are likely to influence the public opinion on CO_2 capture and storage technologies. Some major NGOs do not have a positive attitude to CCS; however some support it, like Natural Resources Defence Council (USA) [Hawkins 2001]. Certainly, not only NGOs but also mass media will influence the attitude of general public towards carbon sequestration. In [DiPietro et al 2004] an analysis of the media and changes in public perception was presented. It showed that the number of articles on carbon sequestration in mainstream media in the US in 2003 was over 80, compared to 35 in 2002. Moreover, the articles in geological CO_2 storage prevailed in 2003 (more than 50%).

4.3.2 UK – Tyndall Centre working papers

The Tyndall Centre has explored initial public opinions of CCS technologies first in 2001 [Gough et al 2001]. In this study a two focus group discussion was held, one of the groups was composed of individuals with scientific background. It should be noted that the findings of this study are preliminary (statistically irrelevant) given that the groups were small and the meetings had been held only once. Nonetheless, the results gave a useful indication for the further research. For instance, the geological carbon storage was preferred over the ocean sequestration since „there was a visible physical barrier to reassure the public that CO_2 could not escape". The authors found out that the public perceives differently the agencies interested in the CCS implementation: e.g. oil companies are suspected in pursuing the continued use of fossil fuels to protect the main business interests.

A later study [Shackley et al 2004] has continued the research by conducting two citizen panels of 5 sessions in York and Manchester and compiling a questionnaire for over 200 individuals. Similarly, it is impossible to consider these results as a representative for the UK population. Therefore further surveying work with larger samples is needed. The surveyed group included more male individuals than female, and there was a fair age distribution.

Comparing the two citizen panels, there had been some difference in acceptance of the climate change science and the seriousness of the global warming threat in general. One of groups was more critical and enquired additional information after the expert presentation. The reason for such a degree of scepticism possibly can be explained by the difference in education, gender and socio-economic status. The authors state that men are more likely to disagree than women and tend to dispute actively in a discussion with an expert. Moreover, this panel included several individuals with degree-level qualifications in scientific subjects, which had also resulted in a more technological and scientific orientation of this group. Interestingly, there was more interest in finding the use for CO_2 rather than just storing it "waste-like" underground. This could indicate that the options like Enhanced Oil Recovery (EOR) may create a more favourable attitude towards CCS. Another citizen panel had focused on the issue of energy demand reduction through lifestyle change. There was more concern on how to effectively communicate the message of global warming and climate change to the general public. Both groups had a similar acceptance of CCS as one of the options for fuels decarbonisation. However, each group had a minority viewpoint regarding the CCS as a morally questionable practice, as it would pose too high risk in terms of geological integrity. Another moral argument was based on the perception of CCS as an "end-of-pipe" technology: "We are treating the symptoms not the causes of doing this"[20].

The authors note that there was a considerable ambiguity in individuals' responses. For example, some respondents would express support for CCS but at the same time would express moral concerns or distrust in the government or businesses intentions. This uncertainty had been identified in many cases of pubic perception investigation, especially with regards to the complex science questions [Shackley et al 2004].

[20][Shackley et al 2004] Shackley, S., Gough, C. Public and Stakeholder Perceptions of Carbon Capture and Storage. Tyndall Centre for Climate Change Research, Report prepared for the GESTCO Project, April 2003, page 24.

The research has shown that at first people are slightly against CCS or there were no widespread positive responses, especially when they were just briefly informed about the option without receiving information on reasons of CCS. Often, the respondents stated that they wanted to know exactly why this is being done and which risks could be involved before making a judgement.

There was a strong support for other methods of climate change mitigation: wind power, wave and tidal power, solar power and energy efficiency were given 80% support. Compared to this, CCS is surrounded by a higher uncertainty which may explain the moderate support (55%). Nuclear power and higher energy bills received negative response. When judging the results concerning energy bills, the authors of the study put it into the framework of equity matters. In the UK energy costs can play a major role in the budgets of private households with low income. The still occurring "fuel poverty" is seen as a serious problem leading to a wide spread objection of higher energy prices.

Regarding the funding and regulating CCS, the majority had chosen "oil industry" and "Government". Moreover, the authors note that many respondents selected "consumers" as the item responsible for CCS funding. Authors explain that many individuals felt that they will end up paying for it, rather than because they felt that they should pay for it. With regard to the regulation of CCS, the common agreement was that "Government" should perform this duty in partnership with environment agencies and NGOs.

At the end of survey opinion changed: 50% of the individuals developed a positive attitude towards CCS and considered as a potentially important carbon mitigation option for the UK. As a result, one could draw a conclusion based on [Shackley et al 2004] that the public tends to favour CCS if it is presented as a part of the wider policy for CO_2 emissions reduction, which would include renewable energy technology and energy efficiency increase. The idea of CCS as a "bridge"-technology towards a hydrogen-based energy system was more acceptable to the public.

The general opinion agrees that mass-media is going to play a crucial role in forming the public opinion on CCS. Moreover, additional specific information about the risks associated with gas leakage and storage safety needs to be provided to inform the public debate.

4.3.3 Climate policy and public perception of CO_2 storage in the Netherlands

Overall, the situation in the Netherlands in terms of favouring the CCS is one of the most advanced in the European Union although there has not been a survey of public opinion conducted yet. Instead in [Lenstra et al 2001] a small inquiry of 12 well informed scientists and NGO members is presented. The author gives an overview about CCS perception by the climate change community which includes NGOs, "energy savers" and "renewables". In particular, the article states that each of those groups regards climate change as a way to promote their goals rather than a problem requiring a solution. In this case, CCS does not fit into any of those goals and thus is opposed by all three groups. As a result, "CO_2 removal is an option which does not easily enjoy public support"[21]. In [Lenstra et al 2000] the strategy to get a stronger support for CCS should focus on a positive involvement of energy industry into the climate change mitigation issue and the broadening the view of climate change community for more possible solutions.

Moreover, the small inquiry presented in the work evaluates arguments and considerations in favour of, as well as against CCS. The arguments considered as most important in this study are presented here (Table 4.1) and are recommended by Lenstra as a useful tool to design an attractive policy strategy which would put the clean fossil energy as part of the solution to the climate change problem.

[21] [Lenstra et al 2000] Lenstra, W., Van Engelenburg, B.C. Climate Policy, CO_2 Storage and Public Perception. Proceedings of the 5th International Conference on Greenhouse Gas Control Technologies (GHGT-5), August 13-16, 2000, Cairns, Queensland, Australia, page 35

Table 4.1. The arguments and consideration in favour of and against CCS with the best score. From [Lenstra et al 2000]

Arguments in favour of CCS	Arguments against CCS
In a serious climate policy all reduction options are necessary that have no large secondary impacts	Financial means spent on CCS go at the expense of the budget for renewable sources and efficiency improvement
Clean fossil energy, in particular hydrogen, induces a change in the energy supply that can benefit renewable energy sources later on	Fossil energy is not sustainable anyhow
Clean fossil energy makes an early bridge to an energy supply fully based on the best renewable sources	CCS is a typical end-of-pipe technology that should be avoided
Renewable energy sources and energy efficiency improvement seem hardly feasible to cause steep reductions of CO_2 emissions in the short term	The environmental risks of CO_2 storage could be very high
	CCS makes an easy way out to continue the fossil energy consumption

The approach to develop a climate policy strategy has evolved over the past 10 years significantly in the Netherlands and is summarised in [Lenstra et al 2000]. The main points of the approach that would help to gain broader public acceptance and develop a new climate change policy strategy are:

- concentrate and focus on end-products, like "clean-energy carriers", rather than conversion processes, as it makes communication easier and helps gaining public support;
- it is important to stress constantly that for the optimal solution of the climate change problem three components are absolutely necessary: energy conservation; renewable energy and climate-neutral use of fossil fuels;
- it is necessary to demonstrate that in the long term improvement of energy efficiency and the use of renewable energy sources will not be sufficient to reduce emissions to a level needed to solve the climate change problem;
- a good demonstration project is needed to show the real example of the large scale CCS technology.

The CRUST Project (buffer project)

This project is an example of an attempt to carry out an inventory of potential underground CO_2 storage facilities, prepare a feasibility study and implement it with the help of Dutch Economic Affairs and Housing Ministry and Dutch Spatial Planning and the Environment Ministry. The Dutch government is seeking to realize the CRUST project before the first commitment period of the Kyoto Protocol in 2008-2012. Therefore, the goal of the project is to interest potential market players to participate in designing and managing of the "buffer" location and to organize the tender procedure [Crust 2002].

There is a strong belief from the authors that such projects require close cooperation between government, researchers, market players and non-governmental organizations. The following subjects are considered in more detail in order to develop such collaboration:

- the economic benefits of implementation;
- the information and communication needed to inform stakeholders and stimulation of awareness in society;
- the legal and permitting framework;
- the safety aspects;

- a monitoring and management plan.

With regard to the public attitude towards geological storage of CO_2, there is a differentiation among the different stakeholder groups: scientific community, market players and general public, which is related to NGOs in this report. Acceptance of the subject in all three groups differs significantly. Thus, the scientific community recognises CCS as a necessary intermediate step towards the solution of the climate change problem, given that the risks have been investigated, whereas market players are cautious to promote CCS without the government support but consider it as an option “worth investigating”. General public has little idea on the subject, however NGOs recognise that acceptance might vary, from “not in my back yard” (NIMBY) effect on the local level to the vision of CCS as one of the blocks for actual CO_2 emissions reduction.

4.3.4 Public perception of geological CO_2 storage in other European countries

A short analysis of public attitude towards CCS has been carried out as part of work for the final report of CO_2 Capture Project [Lee at al 2004]. It is clear that general public is of little awareness about carbon capture and storage in most of the European countries. As it follows from [Lee at al 2004], the position of local and international NGOs and public opinion was investigated in the following countries: Denmark, Germany, Italy, Netherlands, Norway and UK. For this purpose the interviews with representatives of environmental protection agencies and researchers involved in R&D projects on CO_2 sequestration were carried out. In the following sections a short summary on the public perception of CCS in the countries mentioned earlier is presented.

As stated in this report, it is likely that there will be some opposition from local NGOs in Denmark based on the experience store natural gas storage. The project proposed to store natural gas in an aquifer located in the south of the country and it had to be cancelled due to the strong opposition of local NGOs. Moreover, the public has little knowledge about the subject, but an opinion had been expressed that public perception of CCS is likely to be negative rather than positive.

In Germany, it had been revealed that the general public is supporting renewables but “…is unwilling to pay a higher price for energy”. Thus, it will be necessary to start the efforts on convincing the public of the advantages of CCS. It is pointed out that this standpoint is the part of the COORETEC[22] framework in Germany.

In Italy, NGOs show an open position and the public perception is likely to be positive towards the subject of geological storage of CO_2.

As a result of the investigation, the authors state that main environmental NGOs may influence the future acceptance of geological CO_2 storage. Some of NGOs show scepticism whereas others have an open position on the issue. The authors give an example of World Wildlife Fund (WWF) that keeps an open mind on any technology for CO_2 reduction including CO_2 capture and storage but is concerned that the focus of industry on CCS will slow the development of the renewable energy sources. A Norwegian NGO Bellona Foundation is actively supporting CCS, whereas Greenpeace is very sceptical and is expressing the view that CCS might be used as a long-term strategy for oil, natural gas and coal exploration companies to continue “business as usual” scenario. This concern is also expressed by many other NGOs in the Netherlands, as well as in Canada and USA [Lee at al 2004].

4.3.5 Policy and regulatory developments on CCS

There is relatively little being done in terms of policy and regulatory developments on carbon capture and storage in the different countries in Europe. In [Lee at al 2004] a focused survey had been completed by an organized team on the existing policies, regulations, incentives, potentials for

[22] COORETEC initiative – CO_2 Reduction Technologies for fossil fuelled power plants. See www.cooretec.de

CO_2 storage around the world, including such countries like Denmark, Germany, Italy, Netherlands, Norway and UK.

Below is the table where the state of policy on carbon capture and storage is evaluated, based on the survey in [Lee at al 2004].

Table 4.2. Evaluation of the policy on CCS in the European countries

Country	**Evaluation (scale from 0 to 5)**	**Comments**
UK	**5** policy is being developed, R&D activity exist	UK White Paper on Energy Policy includes recommendations for the long-term implementation of CCS technology Member of CO2NET Member of IPHE Member of CSLF
Netherlands	**5** R&D activity and demonstration project exist	2003 Electricity Act establishes a tax to support RES, energy efficiency and CCS Member of CO2NET
France	**3** lack of policy and regulations, R&D activity exists	Member of CO2NET Member of IPHE
Italy	**3** lack of policy and regulations, is likely to support CCS, R&D activity exists	There is a significant interest in CCS from the oil and gas industry Member of CO2NET Member of IPHE Member of CSLF
Denmark	**3** lack of policy and regulations, is likely to support CCS, R&D activity exists	"The Danish Government … So far has adopted a "wait-and-see" policy…"[23] Member of CO2NET
Spain	**3** lack of policy and regulations, R&D activity exists	Member of CO2NET
Germany	**4** lack of regulation, R&D activity exists, supports CCS	Member of CO2NET Member of IPHE Member of CSLF
Poland	**2** lack of policy and regulations, some R&D activity on CCS exists, interest in clean fossil fuel technologies	Member of CO2NET
Czech Republic	**1** lack of policy and regulations, no activity on CCS exist, interest in clean fossil fuel technologies	
Slovakia	**0** lack of policy and regulations, no activity on CCS exist	
Norway	**5** Supportive policies or regulations extended to CO_2 capture and storage (CO_2 tax). Many activities related to oil and gas industry	Country which large scale aquifer storage experience (Sleipner) Member of CO2NET Member of IPHE Member of CSLF

[23] [CO_2 Capture Project] Policies and Incentives Developments in CO_2 Capture and Storage Technology: A Focused Survey by the CO_2 Capture Project

In the following sections a more detailed summary of the existing policies on CO_2 capture and storage examined in the [Lee at al 2004] is given.

According to [Lee at al 2004], *Denmark* participates in IPCC and EU discussions on CCS and is likely to support the use of the technology as a way to reduce CO_2 emissions. However, there is no active position in the government now and in the proposal for a climate strategy for Denmark CCS is considered to be "too expensive to implement". It is also mentioned in the report that under current regulatory framework, offshore geological storage of CO_2 is possible, whereas onshore geological storage will face difficulties doe to the strict regulations on groundwater protection.

In *Germany*, there is an active discussion on the topic of CCS between different authorities. Moreover, Germany is taking part in several international projects like the EU commission R&D projects and the IEA Zero Emission Technology Strategy. However, there is no agreed position of the government on CCS. It is mentioned in [Lee et al 2004], for example, that the Ministry of Environment supports renewable energy economy and the Ministry for Economics and Labour regulates all issues concerning fossil power plants and is likely to accept that German economy will depend on fossil fuels in the nearest future. Now Germany is involved in two EU projects which include CCS technologies (NASCENT; RECOPOL) and has several local projects as well as an initiative started in 2003 (COORETEC). This indicates significant interest from the research institutions and companies in the promotion of CCS. It should be noted though that the roadmap developed within the COORETEC-programme envisages a longer time horizon for the realisation of CCS in large scale demonstration and for its fully economic application

According to the report [Lee et al 2004], *Italy* is interested in CCS technologies due to the fact that the long-term priority is given to the hydrogen production from fossil fuels and renewable energy sources. CO_2 capture and storage is seen as an important component for the hydrogen-based economy. However, there are no existing regulations neither favouring nor restricting CO_2 capture and geological storage.

Netherlands has a different attitude towards CCS. It has an aim to achieve climate change policy's goals by combining the energy efficiency, use of renewable energy sources and clean fossil fuels. Thus, CO_2 capture and storage is seen as a necessary part of the transition to sustainability with a focus on energy efficiency and renewables. Based on the interviews made, the authors state that existing policies are sufficient for the regulation of a CCS project through a system of permits and concessions. As follows from [Lee et al 2004], the Environmental Ministry is going to consider CO_2 as a non-hazardous waste and therefore CO_2 storage in aquifers could be prevented by the current legislation on groundwater protection. A clear policy on CCS is yet to be established by the government, but there is a demonstration project being carried out now in the Netherlands (CRUST) developing legal aspects of underground CO_2 storage.

The investigation has shown that the UK White Paper on Energy Policy published in 2003 recognises the need to invest in CO_2 capture and geological storage. Moreover, UK considers CCS as a long-term method for reaching the government's target to reduce CO_2 by 60% by 2050. The CO_2 Capture and Storage Feasibility Study Advisory Group was created, and it has issued the first study in 2003 which includes recommendations on long-term CCS implementation in UK. Moreover, it is apparent that CO_2 capture and storage is going to be included into the UK climate change mitigation options portfolio.

Regarding other European countries, it is difficult to assess the state of existing policies on CO_2 capture and storage. Apparently, there is a lack of correspondent regulations, although many are moving in the direction of reducing the climate change. Poland [Jankowski 2002] and Czech Republic [Energy Policy 2001] are interested in the development of clean coal or clean fossil fuel technologies. In France there is also interest in CCS which is reflected in [Labeyrie 2003]. A CO_2 Club, an initiative established in France, gathers representatives of heavy industry and public research organisations and is aimed to enhance public/private sector partnerships in order to promote CCS.

4.3.6 Conclusions

Generally a deficit in knowledge about CCS in the wider public but also partly in the professional public has been stated. Further is could be observed that the opinion towards this option usually is not yet firmly set. The high influence of NGOs and mass media on the opinion making hence should not be underestimated. Government policies are often in an early stage of development only. The development of regulations is limping behind the pace required for CCS in order to contribute to climate change mitigation in due time. Several recommendations could be given based on these findings:

The policy makers and stakeholders in the area of CCS should start to reach out to the public and actively promote the debate on CCS. As the topic is gaining increasing attention in the media there is no alternative to this debate. Possibly, lessons could be learned from the debate on the introduction of the emissions trade. Although this is an economic instrument, comparable problems were faced when communicating it to professional public and to the general public.

As the Hypogen programme's objective is to demonstrate the CCS technology in a single facility, it may not be necessary to foster policy and regulation development all over Europe within this programme. Instead it seems more promising to concentrate the efforts to the identification of favourable political environments. These could be characterised by a strong support of lawmakers and official institutions to promote the process of development of regulations and a sound public debate linked to it. An approach concentrating the effort could contribute to keep to a tight time schedule.

4.4 Electricity market

As reported in chapter 3, the de-carbonisation of fossil fuels will increase the cost of electricity production by 30-40%. Therefore this electricity can be competitive in the market only if particular measures will be adopted to promote its production and use.

Two aspects, among other, can affect the economics of Hypogen:

- availability of "subsidies" for de-carbonised electricity, such as "Green Certificates",
- particular electricity price "patterns", such as peak electricity high prices.

Green Certificates

Born with the aim of promoting Renewable Energy Sources, this is one of the most powerful instrument, in the near term, also to foster the utilization of hydrogen. Usually RES are considered the future of the energy system, since they will allow a distributed and peripheral generation of energy, with more resilient energy system networks better integrated in the territory, with lower environmental impact. Of course the same considerations can be applied to the utilization of CO_2-free hydrogen.

The construction of a large energetic basin relying both on renewable sources and on de-carbonised hydrogen end-use may allow to cover a significant part of the heat and energy requirements, attaining in 2010 at least the objective of 25% of electricity production set by the EU directive 2001/77, and of 10% of the thermal requirements.

At the moment in some Member States there already are laws that equalize RES and electricity production without CO_2 emissions, including hydrogen utilization (i.e.: the Netherlands, Italy), so giving another instrument to make plants like Hypogen profitable.

Electricity price patterns

In several countries end user prices of electricity are strongly influenced by time of the day, mainly to foster load levelling. In the case of Hypogen, where hydrogen storage is possible, the project could gain benefits to concentrate electricity production in those hours when the prices are higher, assuring at the same time a steady-state operation of the gasifier. The possibility of operating Hypogen with some flexibility in electricity (and hydrogen for external market) production has to be evaluated during the feasibility study.

4.5 Hydrogen market

A plant like Hypogen produces a large quantity of hydrogen (20,000-30,000 Nm^3/h or more) and requires a correspondent hydrogen demand in the surrounding area of the plant location. Even if, especially in the demonstration phase, the configuration of the plant or its site could be chosen in such a way as to reduce this dependence, the development of a significant market for hydrogen as energy carrier is an essential condition for the co-production of hydrogen in a large scale power plant.

The development of this market requires that:

- most of the technical and non technical barriers, that hinder the deployment of hydrogen, will be overcome before the operation of the plant, and that
- the hydrogen demand will increase, at least on a local scale, so that the production methods used in the first demonstration phase (small on site plants from natural gas or renewables) are inadequate to supply the hydrogen required by the market, also considering possible industrial applications.

4.5.1 Barriers to hydrogen market development

Many challenges must be addressed to introduce hydrogen into the market, for all the individual components of a hydrogen energy system (production, transport, storage, conversion and end-use applications).

Production

Better techniques are needed for both central and distributed hydrogen production. Existing commercial production methods (such steam methane reformation, multifuel gasification, and electrolysis) require technical improvements to reduce costs, improve efficiencies and produce inexpensive, high-purity hydrogen with little or no carbon emissions; Hypogen is part of this effort and can give an important contribution in this direction. Advanced production techniques such as nuclear- or solar-powered thermochemical water-splitting, photoelectrochemical electrolysis, and biological methods require long-term efforts to move towards commercial readiness.

Transport and distribution

A greatly expanded H_2 infrastructure will be needed to support the expected development of hydrogen for stationary and transport applications. Building up such infrastructure requires large investments and demonstration of components for both central and distributed systems, together with improvement of current delivery technologies and dispensing systems. The high capital risk involved requires a gradual approach, promoted by a strong public support and focused in the first phase on some more promising areas and communities.

Storage

None of the current technologies satisfy all the hydrogen storage attributes sought by manufacturers and end users for transport applications. Research and development are needed to lower the costs and improve the performance of current technologies, including the ones linked to compressed hydrogen gas and liquid hydrogen, and to explore higher-risk storage technologies involving advanced materials (such as lightweight metal hydrides and carbon nanotubes).

Conversion and final use

Conversion of hydrogen into useful forms of electricity and thermal energy involves use of fuel cells, reciprocating engines, turbines and process heaters. Research and development are needed to enhance the manufacturing capabilities and lower the cost of fuel cells as well as to develop higher efficiency, lower cost reciprocating engines and turbines. Cost and performance issues associated with hydrogen energy systems for different applications will need to be addressed in tandem with customer awareness and acceptance.

Regulations, codes and standards

To minimise the risk of accidents and any hazards that may arise from the chemical and physical properties of hydrogen, both regulations and legislation are required for production, transportation, storage, and use. Moreover, uniform codes and standards for the design, manufacture, and operation of hydrogen energy systems are of primary importance to speed the development process from the laboratory to the marketplace. Both regulations and standards must be extended or developed, to promote the diffusion of this energy carrier.

Public education and outreach

Hydrogen energy development is a complex topic, and people are uncertain about impacts on the environment, public health, safety, and security of energy supply. Therefore, public education and outreach programmes are an important part of the strategy towards the realisation of a hydrogen-based society. The overall objective of these programmes is to inform and educate key audience and general public of the prospects of hydrogen and related technologies and systems in the near future, and the long-term benefits that would arise with the adoption of these technologies. This effort should be strictly linked to the public education and outreach programme in the field of CO_2 capture and storage which should accompany the Hypogen approach.

4.5.2 Socio-economic and policy issues for the transition towards a hydrogen economy

The transition towards a hydrogen economy will require political and socio-economic measures that

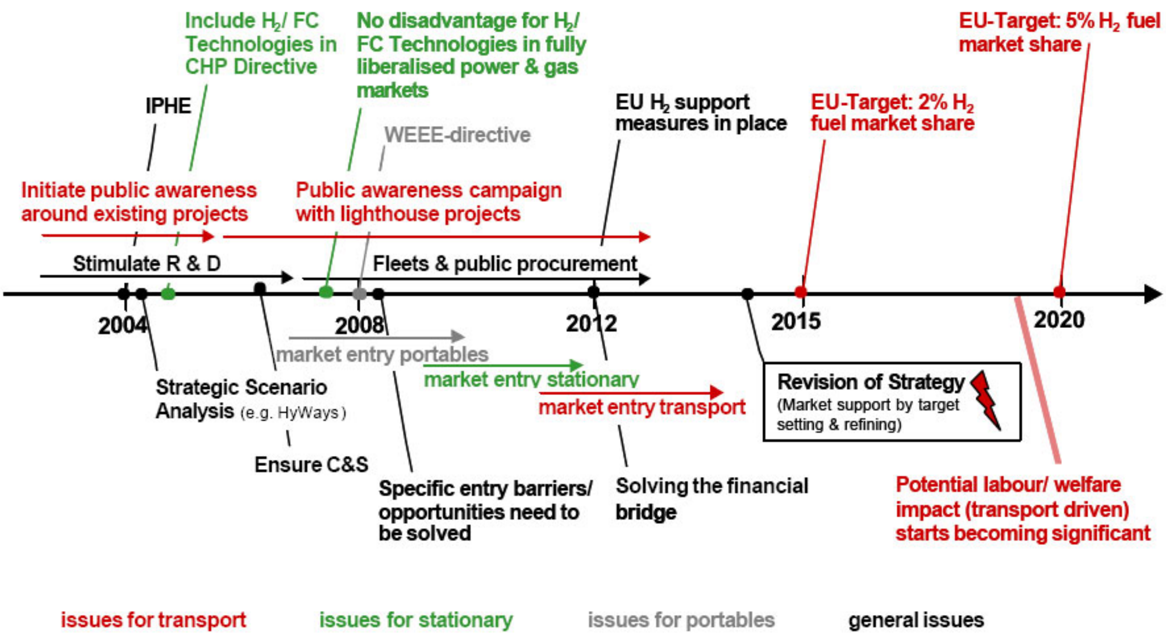


Figure 4.1 – Critical policy and socio-economic issues identified by HyNet (2004)

will both remove barriers and ensure a coherent framework within which different organizations can manage the risks of entering an emerging market.

The work within HyNet (2004) has identified some of the critical actions and milestones needed in the different market phase (Demonstration Phase, Early Markets, Mid & Late Markets), as reported in Fig. 4.1 and in Table 4.3.

Table 4.3 – Critical policy and socio-economic issues identified by HyNet (2004)

Market phase	Policy Issues	Socio-economic Issues
Demonstration	Ensure suitable regulations, codes & standards • Integrated EU approach for mobile, stationary and portable applications • include & build on EIHP and HarmonHy • maintain communication with other regions (US, Japan) • Goal: Harmonised GTR & ISO standards	Strategic Scenario Analysis • analysis of energy supply and distribution pathways • analysis of competitive technologies • labour market analysis including effect on supply chain structures
	Stimulate R&D • Use Framework 6 • Maintain global technology competitiveness • Enhance competitiveness of H_2 technologies	Advocacy of decision makers in public policy and industrial strategy
	Stimulate Demonstration • Develop Public Awareness Campaigns • Lighthouse Projects	
	Drive the Education of Engineers & Staff • Professorial H_2 system chairs funded by EC and industry would help skills base • Develop EU standards for skills and training of technical staff (e.g. handbooks) Education at school level • provide basic H2 knowledge (e.g. teaching mat erial)	Industrial R&D will require significant numbers of engineers & staff compared with today • today only some engineering degrees focus on H2 technologies at a component level • There are very few activities on integrated “system level” (H_2 economy)
	International Hydrogen Partnership • ensure appropriate EU participation • ensure synergies with U.S. and Japan actions	Use portable consumer goods for familiarising the public with H2 applications
Early Markets	As above plus	As above plus
	Ensure EU H_2 support measures in place • fiscal incentives and depreciation regimes • taxation incentives • clear fixed duration & exit strategy	Managing financial uncertainty - help bridge the investment gap • attract venture capital and public/ private funding mechanisms • financing/ funding of infrastructure build up • define acceptable commercial targets and envelope
	Ensure appropriate public/ private procurement • (governmental, e.g. explore opportunities for "dual use technologies") fleets/ lighthouse projects, industry commitment on co-funding, supported by fiscal and legislative incentives • stationary applications (supported by planning & building regulations, energy efficiency standards)	Revision of Strategy: specific entry barriers / opportunities have to be addressed • insurance (barrier) • special mortgage packages (opportunity)
	Ensure favourable conditions for stationary applications in fully liberalised markets • legislation shall not disadvantage hydrogen • develop CHP directive and enable distributed generation	On basis of a technology- neutral CHP directive H2 and FC technology must prove their competitiveness in the CHP and power markets
Mid & Late Markets	As above plus	As above plus
	Ensure competitiveness of H_2 applications • shift from government-driven to free markets • start phase out of support measures as mainstream markets are fully penetrated	Revision of Strategy • Market support by target setting • “Validation” of roadmap legal obligations • 3 possible scenarios: “GO” (fast transient to mass markets), “Slow down” (H_2 in niche markets, transient to mass markets after further R&D), “NO GO”
		Materialisation of positive socio-economic effects • potential labour/ welfare impacts • environmental effects

4.5.3 Hydrogen demand

As the development of the hydrogen demands heavily depends on many technical, economical, social and policy factors, it is very difficult to estimate the volume of hydrogen that will be needed for different applications in the medium term (2010-2015), when Hypogen is expected to operate.

In this first phase of the hydrogen development, the demand for stationary power applications will rely on the natural gas infrastructure and therefore will not immediately impact the hydrogen demand.

In the same period, commercial introduction of hydrogen-powered vehicles, both with fuel cells and internal combustion engines, is expected to begin. The hydrogen fuel demand for this application will gradually become the main driver for developing a wide hydrogen supply infrastructure. However the success will strongly depend on the cost reduction of fuel cells as mainly their application in the transport sector will drive the hydrogen consumption. A rough estimate of the total hydrogen fuel demand has been made by HyNet, considering, for simplicity, only passenger cars.

> *"To give and indication of the volume of hydrogen that will be needed and also underlying the wide range of uncertainty, we can imagine a future scenario where we have a range between 2 and 9 million cars on the road, each with an average annual total driving*

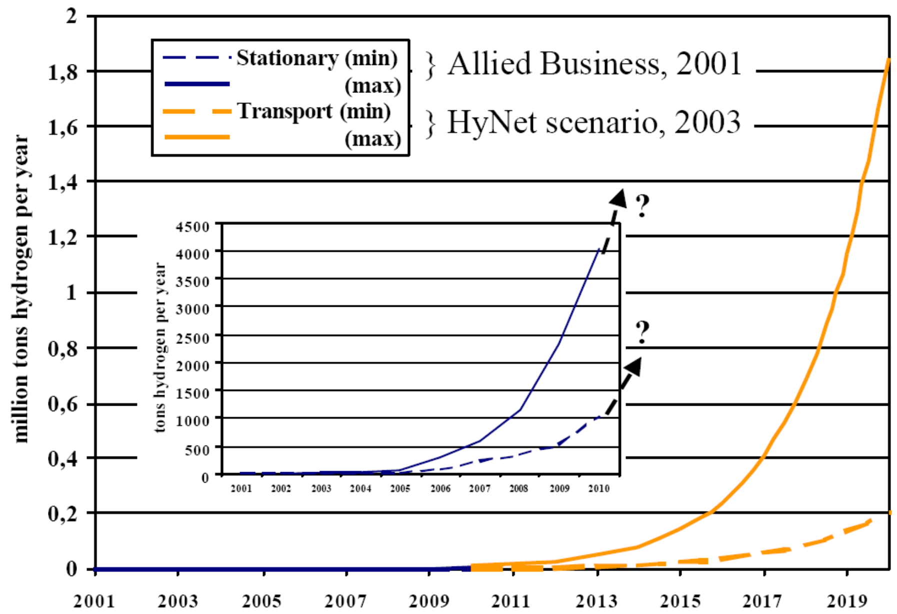


Figure 4.2 - Possible hydrogen demand growth for use as a fuel in Europe (HYNET, 2004)

> *distance of 15,000 km and a specific average fuel consumption of 2.9 – 5.3 L_{GE}/100 km. Using these figures, it is estimated that an extra 2.3 – 20.6 billion Nm^3 or 0,2 – 1.8 millions of tons of hydrogen will be required in Europe annually"* in 2020 (Fig. 4.2).

According to Figure 4.2, the highest hydrogen demand for vehicles that could be expected in Europe around 2015 is of about 1,7 billion of Nm^3/year. To satisfy this demand of hydrogen, about 10 Hypogen facilities would be necessary.

An estimation of the hydrogen demand for vehicles in Europe can also be made assuming that hydrogen will substitute 5% of the energy demand of the road transport sector by 2020, as part of the indicative target of substituting 20% of traditional fuel by alternative fuel, set by the European

Commission [Tzimas and Peteves, 2003]. In this case, the demand for hydrogen in 2020 will be of about 59 billion Nm^3.

4.5.4 Hypogen in the frame of the hydrogen market

As we said before, the introduction in the hydrogen market of a large scale production facility like Hypogen requires that the hydrogen demand is increasing so strongly, at least on a local scale, that it cannot be satisfied by the production of hydrogen in small on site plants, used in the first demonstration phase.

As far as the quantity of hydrogen is concerned, we can assume that the hydrogen co-produced by plants like Hypogen is in the range of 20,000 – 150,000 Nm^3/h (100 – 750 million Nm^3/year, according to the productive capacity of the plant, with a hydrogen generation factor of 5,000 hours) and it could be distributed for a distance up to 200-300 km from the plant.

If this hydrogen is totally used for vehicles, a number of cars ranging between 100,000 and 500,000 will be fuelled, using the assumptions of HyNet for the specific fuel consumption and the total driving distance in a year. This number could be notably reduced, if we include a share of hydrogen-powered city buses, which have a higher specific fuel consumption and greater annual driving distance. For example, if we assume a specific consumption five times higher and a double driving distance, 1,000 buses will require 22,9 million Nm^3/year.

Considering the uncertainties existing in the development of hydrogen demand for vehicles in the period planned for Hypogen operation (2012-2015), it seems reasonable to have a hydrogen productive capacity of the plant in the lower part of the range reported above (for instance, 20,000 – 30,000 Nm^3/h) and to have the possibility of reducing, if needed, the quantity of hydrogen supplied to the vehicle market. This reduction could be possible

- reducing the hydrogen produced by the steam reformer or gasifier,
- using part of the hydrogen for industrial application, with an appropriate selection of the plant site, or mixing it with natural gas (hythane),
- using part of hydrogen inside the plant for additional power production.

To be used in the vehicle market, the hydrogen produced in Hypogen must be cost competitive with other fuels used in the transport sector. Tax exemption may play an important role, as about 80 % of the final consumer price is based on taxes. The tax exemptions for Bio-Diesel in Germany for example have pushed the consumption upwards, even if the production is not cost competitive with diesel from fossil fuels based on production cost.

4.6 Summary and conclusions for Hypogen

- The development of de-carbonisation of fossil fuels for electricity and hydrogen production in a liberalised energy market requires, besides the availability of suitable technologies, a framework that promotes the investments in these environmentally compatible energy systems, making their higher costs affordable at market conditions. The creation of this favourable framework largely depends on
  - the promotion of measures for the reduction of greenhouse gas emissions;
  - the overcoming of some critical barriers related to CO_2 storage (e.g. legal and regulatory aspects, public acceptance);
  - the development of a hydrogen market for stationary and transport applications.

The development of this framework during the next years is of primary importance for the implementation of a full scale demonstration project, like Hypogen. Only then the participation of key industrial players can be assumed.

- The promotion of measures for the reduction of greenhouse gas emission (emission trading) is a long term process that presents a lot of uncertainties. By consequence it is hardly feasible to count on the possible economic benefit from emission trading for the economic of a Hypogen plant. However, Hypogen could benefit by incentives for de-carbonised hydrogen and electricity production, put in place through the tariff structure (like de-taxation and green certificates).
- The permitting for CO_2 storage in geological formation and CO_2 pipelines are new processes, not foreseen in the legislation of most of the European countries. Therefore there is a high risk involved with the legal procedures for permitting, especially for onshore facilities, and there is no knowledge by what time the regulations will be fully developed and the authorities will be capable of handling applications for permits and licenses for transport and storage. This could be a very critical issue for Hypogen.
- Generally a deficit in knowledge about CO_2 storage exists in the wider public but also in the professional public. The opinion towards this option is not usually firmly set yet and the Government policies are often in an early stage of development. An effort has to be done by policy makers and stakeholders to spread the information in this field and to promote the public acceptance of CO_2 storage, that otherwise could represent a barrier for Hypogen.
- As the Hypogen programme's objective is to demonstrate the carbon capture and storage in a single facility, it may not be necessary to foster policy and regulation development all over Europe within this programme. Instead, it seems more promising to concentrate the efforts to the identification of favourable political environments. These could be characterised by a strong support of lawmakers and official institutions to promote the process of development of regulations and a sound public debate linked to it. An approach concentrating the effort could contribute to keep to a tight time schedule.
- The development of hydrogen as energy carrier requires the overcoming of several technical and socio-economic barriers. Even if a large effort is planned in this field in Europe, it is difficult to estimate the hydrogen demand that we can expect in the period of Hypogen operation (2012-2015) and the share of this demand that could be satisfied by Hypogen. In this situation, Hypogen should have some flexibility in hydrogen production and/or supply other markets (e.g. industrial applications), besides vehicles, that will represent the most promising application in this timeframe.
- In conclusion, the Hypogen programme faces significant barriers and risks, related to the uncertainties in the development of a favourable framework. A large share of public funding is therefore needed for the construction and operation of the demonstration plant.

5. ANALYSIS OF THE SYSTEM AND RELATED ISSUES

5.1 Fuel

The choice of fuel for Hypogen plant has to take into account several parameters, such as security of supply, price, availability of proven technologies for hydrogen production, etc.

Possible fuels, and relative hydrogen production processes, are:

- Natural gas: steam reforming, partial oxidation
- Coal (hard coal, lignite): gasification
- Oil: partial oxidation, gasification (heavier distillates and TAR)

A synthetic comparison of the main characteristics of these fuels are reported in Table 5.1.

Table 5.1 – Characteristics of fuels for Hypogen

	Coal	Natural gas	Heavy Oil
Conversion process	Gasification	Steam Reforming, Partial oxidation	Partial oxidation, Gasification
Fuel handling	Difficult	Easy	Medium
Environnemental	Medium	Low	Medium
Plant complexity	High	Low	Medium to high
Conversion efficiency	Good	Very good	Good
Gas cleanup	Easy	Easy	Complex
Fuel cost	Low	High	Low
Fuel availability	Very Good	Medium	Good
State-of-art	Demo	Commercial	Demo
Plant size (Nm3/h H_2)	150,000-	< 200,000	100,000-400,000
Siting	Difficult	Easy	Easy
Plant cost	High	Low	Low
Operation flexibility	Low	Medium	Medium

In this analysis focus has been put on those fuels that seem to have a better potential for utilization in the next future: Natural Gas, Hard coal, Lignite. Heavy oils are not further considered, as their use is mainly limited to refinery applications. Such configurations might be used to cover the additional hydrogen requirements in refineries due to the more tightened fuel specifications.

In the following table the main characteristics of those fuels are summarized:

Table 5.2 – Fuels with best potential

	Hard coal	Lignite	NG
Security of supply	good	highest	medium/low
Transportation	good	not transported	good (pipeline/LNG)
Handling	average	average (specific for fuel chosen)	good
Fuel price	low	lowest	high (price increase expected)
World market for technology	highest	uncertain	large
Environmental impact EU	medium	high	low
Environmental impact world	high	high	low
State of art	Proven commercial	pilot	commercial
Public acceptance	average	low (open mines)	good
Availability	world	local D, CZ, P, GR, US, China	regional restricted
Availability (time)	good	medium	limited (most competing uses expected)
Siting restrictions	medium (need water way)	high (no transport)	low
Ratio CO_2 avoided/kWh_{el}	high	highest	medium

From the assessment illustrated in these tables the following conclusions can be derived:

- Natural gas: the utilization of natural gas in Hypogen will benefit by hydrogen production technology commercially available, with an hydrogen cost that is the lowest in the present conditions. Moreover, this choice could be the most convenient for other advantages related to other factors, like transportation, handling, siting restriction, etc. The critical issues for natural gas, in a long term perspective, are the security of supply, availability and cost. In fact, the increase of gas consumption and the rigidity of gas market "*could give rise to a fresh structural weakness in the European Union*", as reported in the Green Paper on European strategy about energy [EU, 2001]. According to Green Paper,

  "In the long run, the supply of gas in Europe risks creating a new situation of dependence, all the more so given the less intensive consumption of carbon. Greater consumption of gas could be followed by an upward trend in process and undermine the European Union's security of supply".

- Hard coal and lignite: the technology for hydrogen and power production from these fuels (IGCC) still presents a lack of competitiveness, reliability and availability, that has prevented its commercial breakthrough; it is, however, the technology of greatest potential when a near-zero-emissions plant with coal is considered. Moreover, both fuels present some critical issues like environmental impact, handling, siting restriction, public acceptance. These constraints can be offset by factors such as cost, the diversity of outside suppliers and the relative stability of prices compared to fuel oil and gas, if new, more environmentally compatible technologies will be developed.

  "Although in the short-to-medium term there are no major problems regarding security of supply in solid fuels, coal's future depends largely on the development of techniques which make it easier to use (like gasification) and lessen its environmental impact in terms of pollutant emissions through clean combustion technologies and CO_2 sequestration"[EU, 2001].

In conclusion, natural gas and coal present pros and cons that have to be carefully evaluated in the preparatory phase of the Hypogen programme.

5.2 *Plant performance and cost*

The combined production of hydrogen and electricity requires that a pre combustion decarbonisation system will be adopted for Hypogen. A simplified scheme of this system, with natural gas and coal as fuel, is reported in Figure 5.1.

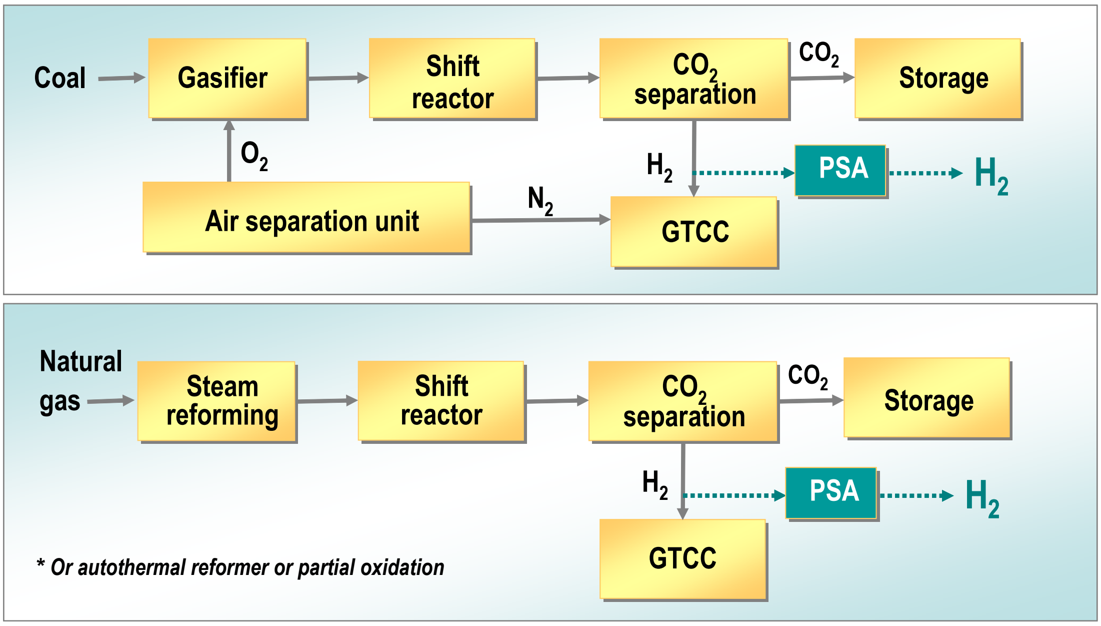


Figure 5.1 - Simplified schemes of pre combustion decarbonisation systems with coal and natural gas as fuel

Several studies are available in literature concerning possible performance and cost of pre combustion decarbonisation systems for power generation [e.g. David and Herzog, 2000; Audus, 2000; Holt, 2003; Tzimas and Peteves, 2003; Hustad, 2001; Ertesvag, 2004]. Some average values are reported in Table 5.3, both with presently available technologies and with improvements expected in the medium term.

Table 5.3 – Efficiency and cost of pre combustion decarbonisation systems with coal and natural gas as fuel

	Natural gas	Coal
Capital cost [€/kW]	1,000 - 1,100	1,800 - 1,900
Efficiency (LHV) [%] (2004)	45 - 48	36 - 38
Efficiency (LHV) [%] (2015-2020)	50 - 52	40 - 42

The cost of electricity and hydrogen depends not only on the system efficiency and capital cost, but also on the operating and maintenance and fuel cost. In particular, the main component in the cost of electricity (and hydrogen) in a coal plant is the capital cost, and in a natural gas plant the cost of fuel.

Little information is available in literature about the cost of hydrogen co-produced with electricity in a system like Hypogen. Domenichini et al. [2004] report 9,25 €/GJ for hydrogen and 5.1 c/kWh for electricity produced in an IGCC plant with CO_2 pre-combustion capture, with a coal cost of 1.35 €/GJ.

For the cost of electricity, many data are available for IGCC plants (pre combustion capture) and for natural gas combined cycle plants with post combustion capture. Only few studies analyse natural gas systems with pre-combustion capture [Hustad, 2001; Ertesvag, 2004], that show in general performance and cost similar to post combustion capture systems.

The estimated costs of electricity for natural gas and coal systems with CO_2 capture are reported in Table 5.4.

Table 5.4 – Cost of electricity for natural gas and coal system with CO_2 capture (based on [Tzimas and Peteves, 2003])

	Natural gas	Coal
Cost of electricity (average value of different studies; available or near-term technology) [c/kWh] *	4.91	6.69
Cost of electricity expected in 2020 [c/kWh] **	4.28	6.11

* Natural gas price (LHV) = $2.78/GJ, coal price (LHV) = $1.18/GJ

** Natural gas price (LHV) = € 3.35/GJ, coal price (LHV) = €1.55/GJ

If only the cost of electricity is considered, a coal based plant with CO_2 capture and storage can be competitive to natural gas combined cycle plants only if the natural gas price exceed €5.7/GJ [Tzimas and Peteves, 2003]. Therefore, the future trend of fuel cost is one of the critical factors to be taken into account in the fuel choice for Hypogen plant, together with the security of supply of different fuels in the long term.

A preliminary analysis of a possible coal-based Hypogen plant has been carried out, in order to clarify some technical and economics aspects of these systems. The results of this analysis are reported in Appendix A.

5.3 Possible solutions for CO_2 storage

Among the wide variety of options for carbon capture and storage three solutions seem to be most promising for Hypogen facility:

- storage in connection with EOR activity,
- storage in a depleted gas field
- storage in a saline aquifer.

Storage in connection with EOR offers the possibility to improve the economics of the carbon capture and storage. Although the value of CO_2 for EOR is limited still, this option should not be underestimated, as a future rise in oil price would increase the value significantly. The problems arising from the low oil price assumptions used in the actual assessments of EOR activities could be avoided with risk sharing contracts. These contracts would link the price paid for CO_2 to the spot market price for oil. With such a risk-sharing contract, the operator of the Hypogen facility would participate in the profits of high oil prices. The risk of low oil prices could be partially hedged with forward contracts. These of course would have only a limited duration that is much shorter than the ideal contracting time for a CO_2 supply for EOR. There are no active EOR operations with CO_2 flooding in the North Sea at the point of time when this study was elaborated yet. However the stakeholders from the oil industries expressed that there are plans for starting such operations in the close future. So there are good chances that some first CO_2 EOR projects have started operation by 2006/2007.

Principally also the production of natural gas can be improved by the injection of CO_2. This would be then one option of enhanced gas recovery. In the discussions with the industry stakeholders, it seemed however that the interest was more focussed to EOR operations in the mid term future. So, although there could be opportunities for onshore EGR projects with CO_2, there seems to be higher interest in the EOR route.

The EOR solution does have further advantages as it uses geologic reservoirs that are already very well explored, that have proven to be confined for a very long time in the past and which are not suitable for other uses due to the content of hydrocarbons. The high margin of geological safety resulting from "proven reservoirs" is partially reduced due to the prior activity hydrocarbon-extraction. The exploration wells, the production wells and possibly other injection wells for water or steam injection into the reservoir constitute possible pathways for CO_2 leakage. This risk of leakage could be managed though as the oil and gas industry preserves sufficient records of the offshore fields. The knowledge of the existence and location of these wells allows to assess the risk of leakage for each of it individually and to approach it with geotechnical methods. This could be measures such as an additional sealing with elastic and acid resistant cements. The geotechnical safety of man made pathways is one of the risks that might need further research.

From a resource economic point of view, the EOR pathway for the Hypogen programme would offer a further advantage. The advancement of EOR in the European oil fields of the North Sea would improve the security of supply. This improvement would occur irrespective of the fuel used for the electricity and hydrogen generation in the Hypogen facility. As discussed already above, there is only a limited time window for the realisation of EOR measures. The Hypogen programme could be part of a strategy that enables the European Oil industry to make benefit of this window of opportunity.

The storage in depleted gas fields also offers a set of advantages compared to aquifer storage. Comparable to the EOR-option this solution would also make use of well explored and well understood geologic structures. The gas fields have proven to be sealed as well. The third parallel is the question of geotechnical safety that had to be addressed carefully. Different to the EOR option, the storage in depleted gas fields would not offer the chance to generate a stream of income. This disadvantage might possible be outweighed by the possibility to locate the Hypogen facility directly at the storage site. There are many gas fields in the Netherlands and in Northern Germany that are reaching the end of production in the nearer future. Thus there are possible onshore sites for storage in depleted gas fields. EOR with CO_2 flooding has not been discussed for any of the few and small onshore oil fields in Europe.

Saline aquifers are the most abundant structure that could be used for storage of CO_2. So, if locating the Hypogen facility will be governed by a number of strongly restricted parameters such as fuel transport, electricity grid connection, local hydrogen demand, public perception, the storage in a saline aquifer might be the most viable option. The degree of exploration of possibly suitable aquifers differs vastly all over Europe. Therefore the exploration requirements and the risk that an intended aquifer structure might prove as not suitable have to be weighed when developing the Hypogen facility. As aquifers are widely distributed and offer a high theoretical potential for storage, the Hypogen programme could improve the overall prospects of carbon capture and storage by adding another real life proof of feasibility to this option. The Sleipner project actually proves the viability of aquifer storage.

5.4 Potential impacts

The construction and successful operation of Hypogen will play a fundamental role in verifying the feasibility of de-carbonisation of fossil fuels for hydrogen and electricity production, with a strong impact on the evolution of the European energy system and on the competitiveness of the European industry.

<u>*Impact on European energy system*</u>

Hypogen will contribute, together with other project ongoing or planned in this field, to demonstrate the technical feasibility and economical viability of the CO_2 capture and storage, and, as a consequence, the possibility of continuing to use fossil fuels in the medium-long term without negative impact on the environment. This situation will promote the development of an European sustainable energy system, where renewable energy sources will be increasingly used within an energy mix that secures energy supply and, at the same time, respects the environmental integrity and European climate obligations.

Impact on hydrogen market

The availability of a large quantity of hydrogen at a reasonable price, as well as general "consensus" generated by the operation of the plant, will promote the development of hydrogen applications, especially in the transportation sector, and will stimulate further initiatives for hydrogen utilization.

Besides this direct impact on hydrogen vehicle market, the availability of important quantities of hydrogen at a reasonable price will result the following main effects:

- enhancement of industrial interest and participation in hydrogen-related activity such us component and system manufacturing for stationary and portable applications, hydrogen vehicles, maintenance and servicing;
- fostering the development of hydrogen communities (HyCom), integrating applications in different sectors (stationary, transport, portable, UPS, ecc);
- development of infrastructures and technologies for hydrogen end-use;
- facilitating the realization of other Hypogen plants;
- development of new initiatives about hydrogen, as a result of the diffusion of "H_2 culture" and of the overcoming of "first" barriers, such as permitting, licensing, insurance, etc.;
- training of specialized workers for hydrogen / CO_2 related jobs;
- facilitating the public awareness of pro and cons of hydrogen / CO_2 technologies;
- promoting the interest of public opinion towards climate-related technologies for energy production, and in general overcome the public diffidence against "hydrogen/CO_2".

Impact on competitiveness of European industry

Besides the positive impact that Hypogen will have on the development of European components and systems for hydrogen applications, this initiative could play an essential role in increasing the European competitiveness in power plant sector. At present, the European power plant suppliers are still worldwide technology leaders. However, given the foreseeable worldwide demand for electricity, it seems very doubtful that they will be able to defend their position or whether this market will be lost to non-EU producers (e.g. USA, Japan, China, Korea). If innovation in the power generation sector does not take place soon in Europe, there is a danger that the European industry will lose their competitive advantage and know-how [Decon and MVV, 2003]. The planning, construction and demonstration of new advanced and environmentally friendly electricity generation systems, like Hypogen, are of paramount importance to reduce this risk.

Impact on employment

Hypogen will stimulate, as previously said, the development of the hydrogen market, with effect on employment both for components and systems manufacturing and for operation, maintenance and servicing. Besides, it will promote the competitiveness of power plant suppliers in the international market and therefore opening the chance for increasing export.

An estimate of the impact of Hypogen on employment related to hydrogen market is very difficult, owing to the uncertainties existing about the development of this market in the medium term. On the contrary, the employment effects induced by investment in the power plant sector as been estimated, for clean coal technologies, to range between 18 and 25 employees per million Euro (2002) investment and year [Decon and MVV, 2003]. Based on this figures, it has been estimated that for every GW installed capacity that is exported, 9,000-15,000 additional jobs can be created per year.

5.5 Possible synergies with similar national/industrial projects

The utilization of an IGCC with CO_2 capture and storage for the production of hydrogen and electricity is under evaluation in Europe also in the frame of national and industrial programmes (see chapter 2); we can expect that some projects will start in near term, if a framework that promotes the investments in these environmentally compatible energy systems will be developed in next years. In the first phase of the Hypogen programme (feasibility study) an effort has to be done to identify the possible synergies with these projects and the most useful interactions with the main stakeholders involved. The co-ordination of the main initiatives carried out in this field in Europe will be needed to optimize the utilization of the considerable resources required.

Besides the synergies with future projects, the experience gained within projects carried out in recent years in related field and the collaboration with ongoing projects will be of great importance for the success of Hypogen.

In particular, the design and construction of the plant will benefit by the work already done for the development and testing of technologies and solutions critical for Hypogen (e.g. gasifier, turbine, plant integration, CO_2 storage). At the same time, the existing or already planned demonstration plants could be used to clarify in advance some key issues of Hypogen. For example, the projects ongoing or planned in the field of CO_2 storage will give an essential contribution in verifying the feasibility of this solution and in promoting the public acceptance and the development of a regulatory framework.

5.6 Preliminary phases of the programme

A big effort is required in the coming years to prepare the ground for the establishment of a large scale facility producing hydrogen and electricity from fossil fuels with CO_2 storage in Europe. Many technical, economical, social and policy challenges must be addressed, in order to identify the best technology options and financing mechanisms, to clarify the environmental and public acceptance issues and to develop an appropriate regulatory framework.

This preparatory work will deal with several critical topics. Some of them are outlined in the following.

Feasibility study. A detailed feasibility study of the plant is needed to clarify the technical and non technical aspects related to his development, to assess the critical technologies, to identify the solutions to be used, to define a preliminary design of the plant, to make an estimation of its cost and an analysis of the environmental impact.

R, D&D activities. Some critical components of the plant, like e.g. turbines, can be tested in existing facilities to verify their performance and identify their best operating conditions. The results obtained in the frame of related projects will be collected and analysed, to clarify key issues that can interfere with the success of the programme, like those involving CO_2 capture and storage (e.g. safety, public acceptance, etc.).

Site selection, monitoring and characterization. The selection of an appropriate site is of great importance for the programme. Therefore the candidate sites must be identified and fully characterised and analysed, to gather all information needed to select a site with favourable characteristics (minimum costs for installation and operation, good connection with electricity and hydrogen market and with CO_2 storage facility, no insuperable barriers for public acceptance).

Permitting. A large plant such as Hypogen will require many state and local permits and presents many new technical and environmental aspects (e.g. CO_2 storage) that will require the development and adoption of novel permitting strategies. Therefore, the permitting procedure could involve a high risk and require long lead time, if all the legal and regulatory aspects will not be clarified in advance, promoting the process of development of regulations needed.

Public information. As reported in 4.3, the public acceptance of Hypogen, and in particular of CO_2 storage, which is an essential part of the programme, can represent a barrier for the construction of the plant. In the preparatory phase it is necessary to address this issue, with information and education activities for key audience (policy makers, NGOs, mass media) and general public.

Promotion of an industrial consortium. The construction and operation of Hypogen is a high risk project and require, besides a large share of public funds, the establishment of a consortium among the companies involved (both technology suppliers and end-users). It is necessary to promote the creation of this consortium in the frame of the 6th Framework programme, through contacts with the industrial stakeholders. It seems to be beneficial, if a consortium formed for the feasibility study under the FP6 would be built in such a way, that the team seems to be able to continue the work in the next phase under FP7.

Identification of funding sources and financial structure of the project. To bear the huge cost of Hypogen a mix of public and private funds is needed, with a share of public funds that should take into account the high risk of the initiative. Different funding sources must be explored, to identify the best solution and to create a financial structure that meets the project requirements and assures the participation of the key stakeholders.

5.7 Financial engineering

The second phase of the Hypogen programme will require large capital investment and present high technical and financial risks. Therefore it cannot financed only by the operating utilities out of own capital and capital raised as loans from banks, as in the conventional scheme used for power plants. A strong public/private partnership has to be put in place to raise the necessary capital for the construction and operation of the facility, that will cost substantially more than a conventional plant and will have higher operating costs.

As the market forces are insufficient to carry on this initiative, the public funds (both national and European) will be essential for the success of the programme and play a key catalytic role in promoting private investments in a Hypogen facility.

The document European Initiative for Growth (COM(2003) 690 final) identifies current and new financial tools to support projects of the Quick Start Programme, like Hypogen. According to this document, Community level support for Hypogen covers, inter alia, the Union’s research budget and the Structural and Cohesion Funds. Moreover, an active role of the European Investment Bank (EIB), in the frame of his collaboration with the Commission, is planned.

In particular, EIB will support the Growth Initiative through:

- Investment in research, development and innovation;
- The European Investment Fund (EIF), that provide risk capital to innovative projects;
- The Structured Finance Facility (SFF), that will contribute to increase the availability of debt finance for the early, pre-construction phase of the projects.

Besides, new innovative financing techniques are under evaluation, such as:

- A new EU Guarantee Instrument, that cover specific commercial risks to projects in their post-construction phase;
- Securitisation, that can help to increase the available pool of resources from financial markets and to reduce the balance sheet and liquidity constraints of banking institutions active in the fields covered by the Growth Initiative.

The critical issue of the instruments and conditions for funding R, D&D of hydrogen technologies is under discussion in the Joint Group of Financing and Business Development, established by the European Platform for Hydrogen and Fuel Cells. Some useful information for Hypogen could result from this work, carried out in collaboration with the Commission and EIB.

National and regional funds can give an important contribution to the financing of Hypogen. In fact, relevant funds are available at national level for the development of sustainable energy systems, even if the possibility for the Government to support private initiative is often limited by the rules of market competition.

Fiscal incentives can be used to help Hypogen initiative, in the frame of the policy measures needed to promote the de-carbonised hydrogen and electricity. Hydrogen production could gain significant advantages from de-taxation, with fiscal incentives differentiated to promote sustainable production systems (from renewable or with carbon capture and storage). Electricity produced by Hypogen could benefit by the incentives presently used for electricity from renewables (Green Certificates), as already done in some European Countries.

A source of additional funding, very vague at present, is the sale of emissions certificates. Possibly the expected emissions reductions could be sold ex ante by committing a bond on the financial markets. Discussions with stakeholders revealed that the feasibility of such a bond is estimated very low. With the start of the European emission trade in the year 2005 the chances to raise capital via a bond could rise. At the given point of time however it cannot be assumed that a significant contribution to the investment costs could be raised through this means.

The identification of financial tools most suitable for Hypogen has to be part of the feasibility study of this programme. In any case, the high risk of the initiative requires a large share of public funds (above 50%), with different instruments and sources. The effective co-ordination of them could represent a difficult and time consuming task, especially if different funding sources should be combined.

As the major risks that affect the programme are related to some critical parts of the plant (CO_2 capture and storage, hydrogen production, advanced components for thermal cycles, integration of the different new technologies in an integrated plants), the public contribution could be especially devoted to this new components, whilst leaving the other parts to be prevalently funded by a consortium of utilities. However it might be difficult to separate the cost between the two types of parts, therefore a cost contribution based on total cost seems to be more appropriate.

5.8 Juridical structure

Based on the risks and large investments required by Hypogen a consortium for the construction and operation of the facility will be the typical juridical structure. However the appropriate juridical structure will be different in each phase of the Hypogen project. In the feasibility study phase, the work could be organised as an IP under the 6^{th} FP. If the detailed planning, purchase and construction phase starts, there will be a need to form a legal entity who will be responsible for this phase, where different companies and institutions holds part of the capital of this entity and which will include other organisation e.g. for questions about public acceptance of CO_2 storage as subcontractors. In the operation phase an additional legal entity might be required to deal with the operation of the Hypogen facility, but with a clear responsability of one company. The consortium and the legal entities should include, as in the case of Puertollano IGCC plant, several utilities and technology suppliers from different European Countries.

The consortium will be responsible of the project and will define and develop it according to the requirements and objectives agreed upon with the public organisation supplying the public funds for the project (European Commission, Member States, Regions) and the industrial stakeholders. As the share of public funds will be high, the form of public/private partnership between the consortium and the main public organizations involved has to be defined to assure an effective participation in all the key choices of the project. Moreover, the public acceptance of the critical part of the project (e.g. CO_2 storage) should be promoted involving in the management of the programme the representatives of local authorities and environmental organizations.

It is not easy to identify the form which the public-private partnership ("PPP") for Hypogen will look like because there is no specific system governing PPPs under Commission law. Some suggestions can be derived from recent documents issued by the Commission on this subject and from other similar European experiences.

A green paper on public-private partnership ("PPP") has been presented by the Commission in April 2004 [COM(2004) 327 Final], with the aim to launch a wide ranging debate to find out whether the Commission needs to intervene to ensure that the economic operators have better access to the various form of PPP in a situation of legal certainty and effective competition.

In this document it is proposed to make a distinction between:

- PPPs of a purely contractual nature, in which the partnership between the public and private sector is based solely on contractual links, and
- PPPs of an institutional nature, involving cooperation between the public and private sector within a distinct entity.

Both solutions present pros and cons, that should be carefully evaluated for Hypogen:

- a PPP of a purely contractual nature could be more flexible and give a clearer separation between public and private sectors; it seems more suitable to realise the project in such a short time as required;
- an institutionalised PPP involves a direct cooperation between the public and private sectors in a forum with a legal personality; it could be a more rigid structure, but allows the public partners, through their presence in the body of shareholders and in the decision-making bodies of the joint entity, to retain a relatively high degree of control over the development of the project, which can be adapted over time in the light of circumstances.

Examples of PPP structures for large initiatives are those proposed for the Galileo programme [PWC, 2001]: a Joint Venture or a Concession Company. In both cases,

- during the development phase the public sector (European Commission and ESA) would hold the majority of the equities and with the private sector as minority;
- at the end of the development phase an Operating Company would be created for the deployment and operation phases.

With the Joint Venture structure the Operating Company would be financed by public equity and grants and private equity and debt, while in the Concession Company model the Operating Company would be a privately owned concession entity, financed from private equity and debt and receiving a payment for his service from EC.

According to this study, the Joint Venture model is a coherent way of meeting the public sector's objectives. But the private sector in general is very reluctant to participate on it or invest under it.

The Concession Company model would give a clearer separation between public and private sectors and provide for the business to be supported during the operating phase by an availability charge for service provision.

5.9 Summary and conclusions for Hypogen

- The de-carbonisation of fossil fuel could represent a key element of the European energy system in a long term perspective. In this perspective, the choice of fuel for Hypogen is a critical issue. Both natural gas and coal present pros and cons that have to be carefully evaluated in the preparatory phase of the programme. In fact, natural gas could be the best choice based on the availability of commercial technologies, while coal seems to be more appropriate to promote, through this demonstration project, a clean production process for hydrogen and power, using a fuel which fulfils the requirement of security of supply in the long term.
- Among the wide variety of options for carbon storage three solutions seems to be most promising for Hypogen:
  - storage in connection with EOR activity,
  - storage in depleted gas field,
  - storage in a saline aquifer.

  The first option offers the possibility to improve the economics of CO_2 storage, while the permitting risk for storage will be lowest. The second gives the possibility to locate the Hypogen facility directly at the storage site. Saline aquifers, being the most abundant structure that could be used for storage of CO_2, might be the most viable option, if a number of strongly restricted parameters, such as fuel transport, electricity grid connection, local hydrogen demand, public perception, have to be taken into account.
- The construction and successful operation of Hypogen will play a fundamental role in verifying the feasibility of de-carbonisation of fossil fuels for hydrogen and electricity production, with a strong impact on:
  - the development of a sustainable European energy system;
  - the development of hydrogen technologies and market;
  - the competitiveness of the European industry;
  - the employment in the field of hydrogen components and systems manufacturing, operation, maintenance and servicing and in the power plant sector.
- Hypogen can have useful interaction with ongoing projects in similar fields and with other projects that are under evaluation in Europe and that could start in near term. The identification of possible synergies in the first phase of Hypogen programme is of great importance in order to co-ordinate the main initiatives carried out in this field in Europe and to optimize the utilization of the considerable resources required.
- Many technical, economical, social and policy challenges must be addressed in detail in the preparatory phase of the programme, in order to identify the best technology options, financing mechanisms, juridical structure and site, to clarify the environmental and public acceptance issues and to bring the development of an appropriate regulatory framework forward.
- Hypogen programme will require large investment and present high technical and financial risks. A strong public/private partnership has to be put in place to raise the necessary capital for the construction and operation of the facility, with the utilization of a variety of funding sources (European, national and regional) and financing instruments, besides incentives for the utilization of de-carbonised hydrogen and electricity. Industry will however only takes action, if the technology is seen cost effective in the mid term.

- The huge effort required by Hypogen, and the complexity of the programme, suggest that a consortium has to be formed for the construction and operation of the facility. This consortium should include several utilities and technology suppliers from different European Countries and have strict connections with the main public organizations involved. Both European and national.

6. ANALYSIS OF KEY RISKS AND CRITICAL SUCCESS FACTORS

6.1 Critical risks

At the given point of project design for the Hypogen programme there is a large number of risks that have to be associated with the project. However, the programme offers a lot of chances and opportunities which might outweight the risks. This could be even more the case, as there are good ways to manage the risks.

6.1.1 Technical risks

The technological risks are involved in using a new set up of technologies:

- *Gasifiers*: up to date the gasification technologies have often shown low reliabilities. This imposes a risk at least in financial terms when acquiring debt capital.
- *Hydrogen burning turbine*: there is no turbine of this kind on the market so far. Although the modifications with regards to proven natural gas turbines are limited mainly to the combustor section, there remains a risk of failure. The risk associated with the turbine possibly could be managed in a variable system design, allowing to bypass the shift reaction in a first phase of the project. Then a more conventional syngas could be burned. However in this case no carbon capture might be adopted.
- *System integration*: the integration of a highly complex system delivered by manufacturers of at least two industry sectors (power generation for CC-plant and chemical industries for gasifier or reformer plant) has lead in the past and could lead in the future to delays in construction, performance and reliability problems.

6.1.2 Risks arising from storage

- As stated in the CRUST-report (CRUST, 2003), the permitting process for storage of CO_2 in a geologic formation onshore was unclear in the Netherlands. The procedures were felt to be complex. For the German case (onshore) it is reported (Gerling, 2004) that the legislation is not developed with the applicability of existing laws being very poor. Although there is only few information available and this relates to two Member states, the conclusion has to be drawn that there is a high risk involved with the legal procedures for onshore permitting. First of all, there is no knowledge by what time the regulations will be fully developed and the authorities will be capable to handle applications for permits and licenses for storage.
- CO_2 storage is a new technology that has a far reaching impact on a (subsurface) part of the environment in terms of space and time. This leads to a high probability that affected persons and groups will at least interact with the authorities during the permitting process. In principle it has to be assumed that from a position of objection there will be legal challenges to any issuing of permits or licenses.[24]
- The permitting procedures for licenses in the offshore hydrocarbon industry are well known. So although there is less risks from this side, there might arise a international legal debate on the coherence of storage activities with the relevant conventions. This could lead as far as an international juridical dispute at an arbitrary court of the conventions. The risk is judged being less for EOR operations. The activities of hydrocarbon recovery are largely exempt from the

[24] This is usally refered to as "Not in my back yard syndrome or 'NIMBY'-syndrome"

conventions. For offshore aquifer-storage this risk is higher, even though the direct injection by pipelines from land is believed to be a permissible option under the terms of the London Convention and the OSPAR convention.

6.1.3 Economic risks

- Emissions trade: besides the option to sell CO_2 as a product to EOR activities, the income through the emissions trade is the only financial stream rewarding for the additional effort of capture and storage. There are only low price forecasts with a level below € 10 per ton of CO_2. But there are also risks of a complete failure of the market like: no accord on reduction targets for the Post-Kyoto commitment period, massive inflow of CDM-credits to the market or a change of allocation methods not attributing a Hypogen facility surplus emission allowances.
- It is questionable whether a single utility will bear the risk of a Hypogen facility. This suggests that a consortium had to be formed for the realisation of the facility. Within a consortium there might arise difficulties to match different strategies for a multiproduct and multi-objective facility.

6.1.4 Risks associated with the programme development

Among the multiple elements of the rationale for the Hypogen programme large scale hydrogen production and CO_2 capture and storage have a prominent position. Together with the realisation of a parallel production of electricity from the facility, the programme would contribute to two major objectives of energy policy. First it would open a path for the decarbonisation of transportation fuels with the use of hydrogen. Doing so, the necessary contribution of the transportation sector to greenhouse gas emission abatement could be realised. Second, it would allow electricity production from fossil fuels compatible with the climate targets.

However, the discussions with industry stakeholders during the preparation of the study showed that the hydrogen path only receives limited support. The readiness of many industry companies to pursue a hydrogen strategy is low, as the risks associated with such a strategy to the business are judged very high. These risks are especially, the technology risk of key elements of the hydrogen facility that are not proven yet and the market risk for hydrogen which is considered hardly manageable. A key point within the risks of the hydrogen market is the weak demand and the unsolved question who will pay for the infrastructure investments required for the hydrogen economy. Further it has to be taken into account that industry companies work under a restriction of resources – not only in terms of capital but also in terms of R&D power. These resources are to be allocated to the development paths with the highest prospects. Among the electricity industry, which would be deeply involved in the Hypogen programme, there are important stakeholders who judge pathways not involving hydrogen more promising. Within this industry, the main goal is to provide technologies to produce electricity and ultimately to produce electricity in accordance with the political and societal goals. Under market conditions this can be done more efficiently with technologies not producing hydrogen according to these stakeholders' assessment. From an economical point of view it is their duty to allocate their limited resources to these most prospective paths.

As a result from this discrepancy between the political rationale and objectives and the industry's strategies, there arises a risk of failure for the programme. Within the time frame of the strategy development a common set of goals of the important stakeholder from both politics and industry has to be found. As the Hypogen programme foresees a large financial input from private companies as well as public contribution a solid consensus has to be found. Only on this base it will be possible to raise the required financial means on both sides, the public and the private one.

6.2 Success factors

To achieve the objectives of Hypogen programme it is necessary to confront many challenges, finding a way to reduce the risks reported above. To this end many actions have to be done, to create a favourable framework that promote the involvement of key players and to clarify all technical, economical, social and political issues that could interfere with the success of this initiative.

The most important success factors for Hypogen, already analysed in different parts of the study, are summarized in the following.

- **Development of a favourable political, financial and regulatory framework**. A clear political will, that promote the de-carbonisation of fossil fuels as an essential part of the strategy for the development of a sustainable energy system, is of paramount importance, both at European and Member States level. In this frame
  - a coherent regulatory framework for emission trading, de-carbonised electricity production, hydrogen market and CO_2 storage has to be developed, and
  - considerable public financial resources have to be devoted to the development and deployment of the needed technologies and infrastructures.
- **Good partnership with key stakeholders.** The involvement of the key players (technology suppliers, utilities, end-users) is an essential condition for the success of the programme. The active participation of the industries requires that:
  - the objectives of Hypogen are perceived as a key component of the expected evolution of the energy system;
  - there is a real industrial interest to apply de-carbonised production of electricity and hydrogen as a long-term option under market conditions.

  At the same time, it is necessary
  - to involve high competent partners, with complementary skills, in the consortium formed for the realisation of the programme, and
  - to set up a consortium structure able to operate with efficiency, taking into account the different interests of the partners.

  The establishment of such a consortium could be a difficult and time consuming task and needs to be promoted as soon as possible.
- **Good feasibility study**. A detailed feasibility study, with the participation of key stakeholders, is needed in the first phase of the programme, to clarify the technical and non technical aspects related to its development and to identify the best solutions for critical plant choices (fuel, technologies, plant location and CO_2 storage site), financing mechanisms and consortium structure.
- **Good financial engineering**. To raise the large financial resources needed for the realisation of the programme could be a difficult task, owing to the existing uncertainties about the evolution of the market conditions for de-carbonised energy systems. A large share of public funds and favourable financing mechanisms are essential to promote the necessary share of private investments. One way to push it forward could be a fixed support per kW_{el} and kW_{H2} installed and linked to the capture rate. However there will be the risk, that if the values will be set at a level too low, no one might be willing to invest in this technology.
- **Selection of an appropriate site**. The selection of the Hypogen location has to take into consideration, as in the case of a conventional plant, the need to have minimum cost for

installation and operation. At the same time, the location largely depends on some critical factors, such as the availability of

- an appropriate site for CO_2 storage,
- a sufficient hydrogen demand in the area of the plant,
- a favourable framework in terms of public acceptance, regulations for the innovative parts of the facility, incentives for de-carbonised hydrogen and electricity, public national and regional funds.

The identification of a site with favourable characteristics is of paramount importance for the success of the programme.

- **Public information and good cooperation with local authority**. The public acceptance of Hypogen, and in particular of CO_2 storage, is critical to the success of Hypogen. Information and education activities for key audience (policy makers, NGOs, mass media) and general public must be strongly promoted in the first phase, together with the involvement of representatives of local authorities and environmental organizations. This will facilitate the acceptance of the plant and the issuing of the necessary permits.
- **Market stimulation in Europe and promotion of technology and know how development.** The main objectives of Hypogen (production of hydrogen for transport sector and de-carbonisation of electricity from fossil fuels) are of paramount importance for the development of a sustainable energy system. The construction and operation of Hypogen will play an essential role in promoting:
  - the introduction in the European market of de-carbonised hydrogen and electricity;
  - the development of European technologies and know how in this field, preserving and improving the competitiveness of European industry in the global market.
- **Choice of technologies with real chance for market breakthrough.** Several technology options are possible for Hypogen, as reported in Chapter 3. The technologies selected in the programme should, at the same time, guarantee the successful operation of the plant and have the best prospects for exploitation in the market of advanced energy systems. Only in this case the programme will involve the key players and achieve its objectives. Therefore a great attention has to be devoted during the feasibility study to the choice of plant configuration and technologies for his main subsystems.
- **Realising side effects including employment and export options.** The impact of Hypogen on hydrogen market will have a positive effect on employment, not only for components and system manufacturing, but also for operation, maintenance and servicing. Moreover, the competitiveness of European industry in hydrogen and power generation market could offer new export opportunities, increasing the employment in these sectors.

7. CONCLUSION AND RECOMMENDATIONS

In order to achieve the ambitious objectives of Hypogen, large efforts are needed in order to focus on the necessary resources and competences of the programme, involving the key industrial players, and establishing useful synergies with other European and national programmes.

Several technical and non technical barriers that can hinder the development of the programme exist. A clear political will and consistent actions, together with the availability of a large share of public funding, are required to remove these barriers and to create, also through the realization and operation of Hypogen facility, a framework that promotes, in a long term perspective, the competitiveness of these systems in the energy market.

From the present study we can derive the conclusions and recommendations reported below.

<u>Fuel and plant configuration</u>

- Hypogen can use natural gas or coal (or lignite) as fuel. Both solutions present pros and cons that have to be carefully evaluated in the preparatory phase of the programme. Even if natural gas could be the best choice based on the availability of commercial technologies, coal seems to be more appropriate in order to promote, through a demonstration project, not only hydrogen production, but also a clean technology for power generation, using a fuel of great importance for the security of the supply in the long term.
- The construction of Hypogen involves some technical risks, related to the reliability of the components (e.g. the gasifier), the availability of hydrogen burning turbines and system integration. These technical problems could be increased by the introduction of CO_2 capture, that substantially changes some sections of the plant. Some actions have to be planned in the first phase of the programme to reduce these risks, utilizing as much as possible the existing projects and demonstration plants to gain experience and identify the best solutions for the plant optimization with commercial or almost commercial technologies.
- Some flexibility is required to the plant to shift the production between hydrogen and electricity. In principle, this flexibility could be possible:
  - varying the production of hydrogen by the steam reformer or gasifier according to the external demand;
  - using part of the hydrogen produced for industrial application, with an appropriate selection of the plant site, or mixing it with natural gas (hythane);
  - storing part of the hydrogen produced or using it inside the plant for additional power production.

  The most viable solution has to be identified during the feasibility study and design of the plant, in order to minimize the plant cost and the reduction of the overall efficiency.
- The total carbon capture rate in Hypogen should be as high as possible, as Hypogen should be an ultra clean plant with very low specific emissions. According to the demonstrative character of the facility, a total capture rate between 85 and 95% could be appropriate, in order not to increase the efficiency loss and investment costs of the plant too much.

<u>CO_2 capture and storage</u>

- The feasibility of the permanent storage of CO_2 is critical to the success of the de-carbonisation approach and represents a risk associated with the construction of the Hypogen facility. In order to reduce this risk, it is necessary to address, before the construction of the plant, several issues related to safety, selection of the site, public acceptance and permitting.

- A detailed feasibility study and the utilization of the experience gained in other projects concerning CO_2 storage, are needed to identify and characterize the candidate sites. Among the wide variety of options for carbon storage, three solutions seem to be most promising for Hypogen:
  - storage in connection with EOR activity,
  - storage in depleted gas field,
  - storage in a saline aquifer.

  All options present pros and cons, that have to be carefully evaluated, to identify the most viable solution, that will also heavily depend on the key parameters that affect the choice of the plant site, such as fuel transport, electricity grid connection, local hydrogen demand, CO_2 transport, public perception.
- There is a high risk involved with the legal procedures for permitting and with public acceptance of the CO_2 storage. In order to reduce this risk, an effort has to be done by policy makers and stakeholders to foster the development of required regulations and to spread the information in this field. Since the Hypogen programme's objective is to demonstrate the carbon capture and the storage in a single facility, it may not be necessary to foster policy and regulation development all over Europe within this programme. Instead, it seems more promising to concentrate the efforts on the identification of favourable political environments.

Hydrogen and electricity market

- One of the main objectives of Hypogen is to promote the development of hydrogen technologies and application, supplying a large quantity of hydrogen at a relatively low price, in the area of the plant. Considering the existing uncertainties about the hydrogen demand we can expect that in the period of Hypogen operation (2012-2015), Hypogen should have some flexibility in hydrogen production and/or the supply for other markets (e.g. industrial applications), besides vehicles, that will represent the most promising application in this timeframe. This requirement must be taken into account in the plant design and in the selection of plant location. Hypogen should be able to operate under market conditions after 2015.
- The introduction of the de-carbonised hydrogen and electricity in the market could gain significant advantages from incentives, such us the de-taxation for hydrogen and the "Green certificates" for electricity. These incentives, already available in some European countries, could improve the profitability of Hypogen and have to be considered in the selection of plant location.
- Hypogen could benefit by concentrating or increasing electricity production in hours with higher prices, through hydrogen storage. The possibility of operating Hypogen with some flexibility in electricity (and hydrogen) production has to be carefully evaluated during the feasibility study.

Selection of plant site

- The selection of Hypogen location has to take into consideration not only some factors typical of conventional power stations, such as the availability of a connection to the electricity transmission/distribution system, the proximity of the electrical demand, the availability of fuel and water for the cooling system, but also some critical factors related to CO_2 storage and hydrogen market.

- To be able to promote the introduction of hydrogen in the market, especially for vehicle application, Hypogen should be located inside or near an area where the hydrogen demand is or is going to become comparable with the productive capacity of the plant. As hydrogen demand from the transport sector will normally not absorb the hydrogen produced in Hypogen, also possible industrial applications have to be considered. This is the first, most important requisite for Hypogen location.
- The other important issue to take into consideration is the availability of an appropriate site for CO_2 storage. According to the rough estimates existing for CO_2 transportation costs, a long distance (more than 200-300 km) between plant and storage site could be acceptable only if CO_2 is used for enhanced oil recovery, with an income that counterbalances, at least in part, the transportation cost. Otherwise a depleted gas field or a saline aquifer has to be available not too far from the plant.
- The plant has to be located in an area that presents a favourable framework in terms of public acceptance, regulations for innovative part of the facility, availability of incentives for de-carbonised hydrogen and electricity, availability of public regional or national funds.

Connection with other European projects

- The co-ordination of Hypogen with other initiative that could start in Europe in similar field is essential to optimize the utilization of the considerable resources required and to identify the possible synergies and the most useful interaction with the main stakeholders involved. At the same time the existing or planned R, D & D projects has to be used to clarify in advance some key issues of Hypogen and to reduce risks related to its construction and operation.
- In particular, the development of hydrogen as energy carrier in the transport sector, and the overcoming of related technical and socio-economic barriers, heavily depend on the large effort planned in this field in Europe, effort that includes, besides Hypogen, several other actions and projects (e.g. Hycom). A strict co-ordination among different initiatives is essential to create the necessary favourable framework and to make available some technologies and infrastructures needed for the utilization of hydrogen produced by Hypogen.

Financing

- Hypogen programme will require large investment and present high technical and financial risks. The financial feasibility of the programme has to be guaranteed by the contribution from public funds (both European and national) and the supply of favourable debt capital from institution like EIB. These sources will have to supply the incremental funds that will open the opportunity to the private equity investors to yield the required return on this kind of project.
- The identification of financial tools for Hypogen will be an essential part of the feasibility study of this programme. Some useful information about them could result from the work ongoing in the Joint Group of Financing and Business Development, established by the European Platform for Hydrogen and Fuel Cells. In any case, different instruments and sources will be needed and the effective coordination of them could represent a difficult and time consuming task.

Partnership

- The high risk and large investments required by Hypogen suggest that a consortium has to be formed for the construction and operation of the facility. This consortium should include several utilities and technology suppliers from different European countries and have strict connection with the main public organization involved, both European and national. Moreover, the public acceptance of the critical parts of the project (e.g. CO_2 storage) should be promoted involving in the key choices the representatives of local authorities and environmental organisations.

- The creation of a strong industrial consortium could be a difficult and long process. It is necessary to promote its formation in the first phase of the programme, involving the key stakeholders in the feasibility study through the calls of the 6th Framework Programme.

In conclusion, big efforts are required in the coming years to prepare the ground for the establishment of a large facility producing hydrogen and electricity from fossil fuels with CO_2 capture and storage in Europe. Many technical, economical, social and policy challenges must be addressed, in order to identify the best technology options and financing mechanisms, to clarify the environmental and public acceptance issues, to develop an appropriate regulatory framework and to promote the establishment of an industrial consortium for the realisation of the project.

To this end, a detailed feasibility study is needed, dealing with:

- Technical planning,
- Site selection, monitoring and characterization,
- Permitting,
- Public information
- R, D & D support activities.

These actions have to start as soon as possible, under the framework of the calls of the 6th Framework Programme.

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Appendix A

Preliminary analysis of a possible coal-based Hypogen plant

Preliminary analysis of a possible coal-based Hypogen plant

The de-carbonisation of fossil fuel could represent a key element of the European energy system in a long term perspective. In this perspective, the development of clean coal technologies is very critical and the use of coal in a demonstration project like Hypogen could promote not only hydrogen production, but also a clean technology for power production, using a fuel of great importance for the security of supply in the long term. For this reason a preliminary analysis of a possible coal-based plant has been carried out, even if other technology solutions, based on natural gas, are possible for Hypogen and the choice of fuel and plant configuration is at present completely open.

Following the pre-assessment of technology options, an IGCC with hydrogen production and CO_2 capture has been analysed, using data available in literature.

A comparison of costs and performance of modern coal plants, with and without CO_2 capture, is reported in the table below. The study was made considering commercially available technology and includes the cost of compressing the captured CO_2 to about 100 bar for pipeline transportation. The cost of electricity here reported does not include the cost of CO_2 transportation and storage [David & Herzog, 2000].

Tab. A.1 – Performance and cost for coal plant with or without CO_2 capture [David & Herzog, 2000]

		IGCC	NGCC	PC
Capital Cost [$/kW]	Without CO2 Recovery	1401	542	1150
	With CO2 Recovery	1909	1013	2090
Thermal Efficiency (LHV) [%]	Without CO2 Recovery	42,2	55,0	41,2
	With CO2 Recovery	36,1	47,8	30,9
Cost of Energy [c$/kWh]	Without CO2 Recovery	4,99	3,30	4,39
	With CO2 Recovery	6,69	4,91	7,71

In general, due to the introduction of carbon dioxide capture and storage units, other literature references report different energy penalties, depending on the used technology, in the range of 2–12 percent points [O'Keefe, 2002]. The additional energy consumption for CO_2 capture and storage is estimated to result in the drop of the power plant efficiency by 13 to 25% [Tzimas and Peteves, 2003]; also capital cost values vary in a wide range from 1620-2200 €/kW [Audus, 2000; Holt, 2003] especially considering different gasifier technology (wet/dry feed, quench/syngas cooler). Thinking to future trends, technological improvements in power generation and in carbon capture and storage can lower the specific cost of electricity and hydrogen production. Capital investment can be lowered and efficiency increased. Moreover improved solvents will reduce the efficiency and cost penalty for de-carbonization. Different authors have proposed increasing values for net efficiencies and decreasing values of specific capital costs. An example of expected future costs and efficiencies is reported in the table below.

Table A.2 – Performance and costs for future IGCC plants

Time Horizon	Capital Cost	Cap. Cost CO_2 Cap	Efficiency	Efficiency CO_2 Cap	Author
year	€/kW	€/kW	%	%	-
2012	1145	1459	47.8	43.5	David and Herzog
2020	1333	1856	50.0	41.7	Tzimas and Peteves

1. Plant Configuration

Different options have been pursued in order to evaluate the best available configuration suitable for a possible coal-based Hypogen Plant. Two different situations are considered in this study, the one is a electricity and hydrogen co-production plant while the second is characterized by only electricity production. CO_2 will be made available at the boundary of the plant ready to transport (at about 100 bar and ambient temperature). No analysis has been done about distribution of hydrogen (available at fence at 15 bar and ambient temperature).

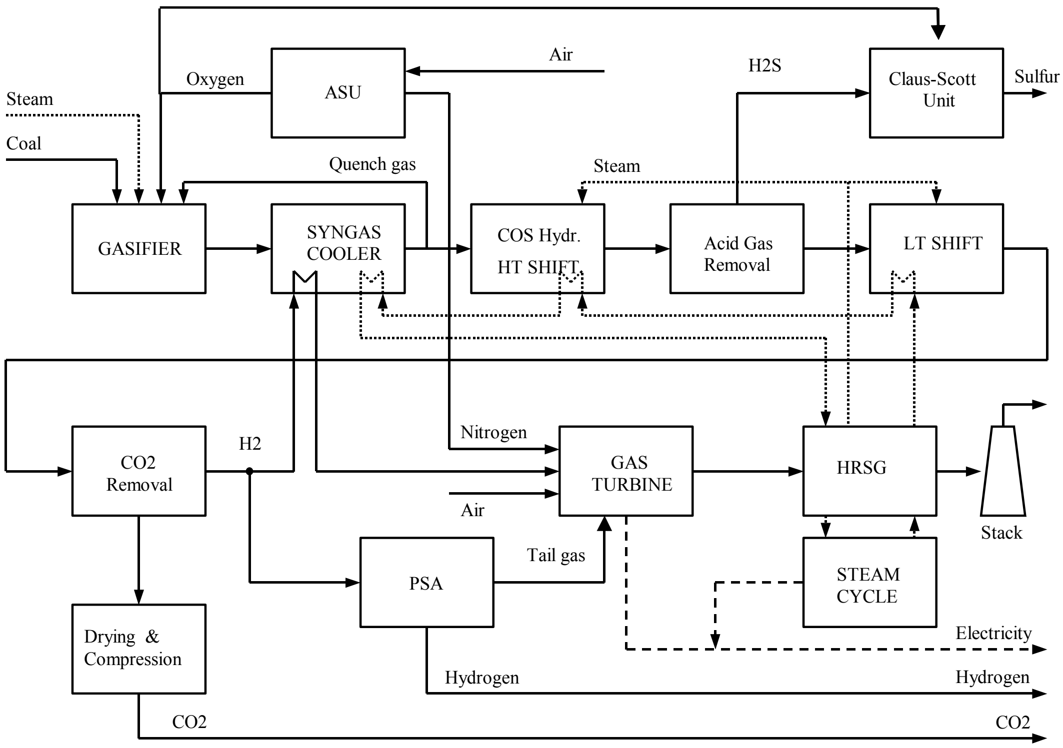

Figure A.1 - Schematic flow diagram of a coal-based Hypogen IGCC plant

The baseline capacity of the plant is 192 MWe but is capable to reach 255 MWe when only electricity is produced. The size is similar to that one of IGCC plants effectively build in EU (Buggenum or Puertollano), however it is strongly influenced by the nominal power of gas turbines currently commercially available.

Considering the uncertainties existing in the development of hydrogen demand, as reported in chapter 4, the hydrogen productive capacity of the plant has been fixed at a relatively low level; moreover, the plant can operate converting all the syngas produced into electric energy, if no hydrogen is required by the external market. The maximum hydrogen production, for 6,750 hours of operation, is about 210 million Nm^3/year; the amount of CO_2 to be stored ranges between 1.42 and 1,7 million ton/year, according to different plant configurations.

Using two different industrial codes (ChemCad and IpsePro), on purpose developed for the thermodynamic analysis of the energetic systems, the plant behaviour has been simulated. The hydrogen purity at batteries limits is good for combustion, further cleanup is needed if the aim is utilising hydrogen in fuel cell systems. Initially two configurations have been considered, the first one characterised by electricity and hydrogen production (EHP) and the other one by electricity only production (EOP). The different analysis have been made with the same coal feeding. Results show a low efficiency in the EHP case due to off design conditions of GT. Finally, to increase plant performance, a third configuration, with extra coal feeding and gas turbine on nominal point has been considered.

Table A.3 – Design Criteria for Hypogen Plant

Hypogen Plant Parameter	Hypogen Plant Design Basis for Coal
Ambient Conditions	1,013 bar, 15 °C
Coal Feed	Hard Coal
Gasifier	Dry-feed, pressurized, oxygen blown entrained bed gasifier, slagging type
Coal Feed Rate	2700 tpd
Hot Gas Temperature	800-900 °C
Gasifier Outlet Pressure	25 bar
Gas Quench/Cooling	400°C
Raw Gas Filtering	Metallic or ceramic candle filter
CO-Shift	Single stage high temperature sulfur tolerant
Desulphurisation	Physical absorption [Glycol (Selexol) or Methanol (Rectisol) solvent]
Sulphur Recovery	Claus-Scott process
CO_2 recovery	Physical absorption [Glycol (Selexol) or Methanol (Rectisol) solvent]
Hydrogen Purification	Pressure swing adsorption
PSA tail gas	Fired in post fired HRSG or in auxiliary boiler
Plant Capacity Factor	75 %

Table A.4 - Parameters and operation mode of the plant

Parameter		Value	
Load factor		75%	6750 h/yr
CO_2 separation		90 %*	
Operation mode		Power	Hydrogen
Electric Only Production	A	192 MWe	0 MWe eq.H_2
Electric and Hydrogen Production	B	255 MWe	768,854 Nm^3/d
Electric and Hydrogen Production	C	259 MWe	768,854 Nm^3/d

* With 93% removal of CO_2 by the recovery unit following a 97% conversion of CO in the shift reactor the overall carbon removal is 90%.

The reference performance is a conventional IGCC, without shift reaction and CO_2 removal sections. In this kind of plant syngas leaving the acid gas removal (AGR) section is directly delivered to the gas turbine. In the first case, due to the presence of physical solvent CO_2 recovery system the net efficiency drops close to 36%. A decrease of about 8 efficiency points respect to the value without CO_2 capture and compression has been estimated, according to average values reported in literature [David and Herzog, 2001; Tzimas and Peteves, 2003]. In the second one the decrease in efficiency is a bit higher (~9%) because both GT and HRSG work in off design. Because of lower performances a third case with an extra coal supply has been considered to produce electrical power in “on design” conditions and 0.8 kg/s of hydrogen. These and other results are shown in the table A.5.

Table A. 5 – Performance analysis results, CO_2 compression included

Case		A	B	C
Mode		Electric Only Gasifier+GT on design	Electric & Hydrogen GT off design	Electric & Hydrogen Gasifier off design
Coal flow rate	kg/s	28.55	28.55	34.03
	t/d	2,467	2,467	2,940
Gasifier load/on design load	%	100.0%	100.0%	119.2%
O2 flow rate	kg/s	23.03	23.03	27.45
Syngas flow rate	kg/s	51.64	51.64	61.55
Gross Electric power	MWe	315	243	325
GT load /on design load	%	100	68.7	100
GT power	MWe	182	125	182
ST power	MWe	133	118	143
ASU consumption	MWe	22.3	22.3	26.6
Auxiliary consumption	MWe	37.8	29.2	39.0
Net power	MWe	255	192	259
Net efficiency	%	35.7	33.5	36.6
H2 production	kg/s	0	0.8	0.8
	Nm^3/d	0	768,854	768,854
CO2 production	t/d	5,766	5,766	6,873
CO2 sequestered (90%)	Mt/yr	1.429	1.429	1.704
CO2 sequestered (90%)	td	5,223	5,223	6,225
CO2 emitted	t/d	543	543	648
	g/kWh	89	118*	104*

* charging CO_2 production on electric production only

In the first case (electric only production) all the treated syngas burns in the GT, instead in the second case (co-production of electricity and hydrogen) the syngas has to be split to GT and PSA stream, in order to generate 192 MWe and 96 MWt of hydrogen. The effective amount of produced H_2 has been calculated considering the LHV (119,972 MJ/kg_{H2}) efficiency of the syngas to electricity cycle (considering a syngas to power cycle efficiency of 52%, 0.8 kg/s of hydrogen are equivalent to 50 MWe). Only hard coal feeding have been considered (also lignite could be a candidate), 99% of sulphur removal is expected using common cleanup process (physical absorption), at the same time at least 90% of the carbon dioxide is recovered for use in enhanced oil recovery or for geological storage in deep saline aquifers.

In the first case (A) in front of 2,467 tpd coal consumption (25000 kJ/kg LHV, 63.75% carbon content) and 75% availability, the whole process yields 1674 GWh/y. In the case of co-production with less power from GT (B), for the same coal consumption and availability the plant yields 1258 GWh/y and about 69 tpd (equal to 768 thousand of Nm^3/d as in case B) of high purity hydrogen viable for transport use, chemical industry or to produce more electric power, with about 543 tpd of emitted CO_2. In the last co-production case (C), the coal supply is augmented to 2,940 tpd coal consumption, the power production is about 1,704 GWh/y and hydrogen production is the same as in case B. In all cases the efficiency in carbon dioxide removal is about 90%. The detailed results are shown in table A.5.

2. Main components

A brief description of main blocks is provided below.

Gasifier: gasification based on a dry-feed, pressurized, oxygen blown entrained bed gasifier, slagging type has been select, because of best results in terms of efficiency and compactness but with also taking in account more expensive specific capital costs. In this kind of gasifier the coal is pulverized and dried prior to being fed into the gasifier with nitrogen as transport gas. Coal, oxygen and steam enter the gasifier through horizontally opposed burners. Raw fuel gas is produced from high temperature (1400°C) gasification and flows upwardly. The high reactor temperature converts the remaining ash into molten slag which flows down the walls of the gasifier and passes into a slag quench bath. The reaction temperature is controlled by using part of the heat of reaction to generate high pressure steam in the membrane walls of the gasifier. In order to avoid problems with molten or sticky fly slag particles entrained in the syngas, a quench flow concept was selected [Postuma et al., 2002]. After quenching the raw syngas down to approximately 800-900°C, with recycle dust-free syngas, further cooling (up to 350-400°C) is done by raising steam in the syngas cooler. Solids are recovered in a following particulate filter and recycled back to the gasifier.

CO shift and cleanup: after cooling, the COS hydrolysis take place in an appropriate reactor. Downstream to increase the H_2 content and to help the successive CO_2 recovery, the syngas, still high in CO, has to be sent to the shift section. The shift reaction (90% conversion of CO to CO_2) is accomplished in a catalyst packed tubular reactor. Upstream injection steam is supplied by the Heat Recovery Steam Generator (HRSG) and additional cooling is provided by external heat exchange. A relatively low cost iron catalyst, effective in the temperature range of 350-450°C, make the process suitable (in the case of high H_2S content syngas the shift is “sour type”, no COS hydrolyser is required because catalyst promotes also the COS definitely conversion to H_2S and CO_2). Raw gas is then treated in the treatment and conditioning section to remove all the contaminants like sulphur compounds. The acid gases removal unit (AGR) is made by a physical solvent washing (Glycol or Methanol solvent). A H_2S rich stream coming from the AGR regenerator is burned in the presence of oxygen in a furnace followed by two reactors where the Claus reaction take place to produce liquid sulphur. The tail gas from Claus unit is treated to convert SO_2 to H_2S in a catalytic hydrogenation and sent to AGR unit after compression. To reach a better CO conversion (up to 97%) is possible to add downstream a low temperature shift reactor that works at about 200-250°C with Cu based catalyst. This would increase also the global CO_2 capture to 90% or more.

CO_2 recovery: thanks to high carbon dioxide partial pressure the recovery could be based on a physical absorption process in which CO_2 is absorbed by a solvent. An example could be the Selexol Process which uses dimethyl ether of polyethylene glycol (with proprietary additives) as solvent. The solubility of CO_2 in the solvent is highly dependent on temperature and pressure. In order to absorb significant amounts of CO_2 at economics rates of solvent flow the process must be operated at elevated pressure and at near ambient temperature or below, (e.g. in Rectisol process temperatures far below zero are reached using self generated cooling by gas expansion). Solvent regeneration is accomplished by flashing or by heating. With 93% removal of CO_2 by the recovery unit following a 97% conversion of CO in the shift reactor the overall carbon removal is 90% (thanks to the presence of the LHT Shift Reactor). A CO_2 rich stream has to be sent to reuse or storage (after drying and compression to about 100 bar). However drying is only needed, if water based solvents have been used for capture.

Pressure Swing Absorber: in the baseline case part of the raw hydrogen is sent to a section of purification while the other one is delivered to gas turbine combustor. A pressure swing absorber (PSA) is commonly used in the purification of hydrogen. It is a semi-continuous process, which yields about 60 tpd of a very high purity hydrogen product with some minor argon dilution. The blow down product (tail gas) could be delivered to GT combustor employed in power and/or steam generation due to its high heating value.

Air Separation Unit: the oxygen required both for the gasification and for the Claus reaction is produced in an advanced cryogenic air separation unit (ASU) where air is fractionated by cryogenic distillation. The ASU could be partially integrated with the power generation island, in fact a portion, or all compressed air required by the oxygen plant is delivered directly from the gas turbine compressor, while nitrogen could be injected into the gas turbine for NO_X reduction.

Gas turbine: The reference combined cycle power plant is based on a large heavy-duty gas turbine from which the exhaust gas is led to a heat recovery steam generator (e.g. General Electric 7F, Siemens V94.3, Alstom GT13E2 are already operative in oil refineries and IGCC demonstration plants [Eldrid, 2001, Reiss, 2002]). Gas turbine technology is well known and commercialised for a variety of fuels, including natural gas and fuel oils. Operation of gas turbines on hydrogen fuels, however, is still relatively new, but many studies have been made to value the impact hydrogen fuel will have on system design and operation. The use of high hydrogen content syngas needs substantial burner adaptation because hydrogen flame speeds are about one order of magnitude higher than that of natural gas, because of wide ignition limits and reaction time about one fifth of that of natural gas. Another potential technical hurdle for hydrogen-fuelled gas turbines is the high operating temperature. Temperature-resistant materials and better cooling techniques are required also if nitrogen dilution is adopted. The technology for hydrogen gas turbine (H class) already exists but still needs some development. Higher temperature and efficiencies can be reached. This kind of gas turbine is designed to achieve 60% net plant combined-cycle efficiency with natural gas as fuel. The three key components are closed-loop steam cooling, higher pressure ratio, 1400°C firing temperature, dry low NO_X combustion system as referred by GE Power Systems [Eldrid, 2001].

Steam Cycle: steam is raised at three different pressures with a reheat loop. Parameters necessary for the calculation of the turbine and for the design of the boilers and steam turbine, are chosen according to common practice for high efficiency combined cycles and reflects proven combined cycle technology. Major components include a heat recovery steam generator (HRSG), steam turbines (high, intermediate, and low pressure), condenser, air or steam bleed for gas turbine cooling, recycle water heater, and deareator. The raw fuel gas is cooled in the raw gas cooler that follows the gasifier. Moreover there will be a number of supplementary heat exchangers (membrane wall, shift reactors, compressor intercooling) that supply low quality heat for condensate reheating in the steam cycle. Steam generation occurs at the three pressure levels (typical values could be of 6, 24, and 130 bar) in the HRSG. The cycle includes a parallel superheating/reheating section that raises the temperature to 516°C, for both the high pressure steam and for the combined intermediate pressure steam and high pressure turbine exhaust steam. The LP steam turbine discharges at 33 °C and 0.05 bar.

3. Environmental Performance

Generally, public acceptance, permitting success and timing, and compliance costs are all directly affected by environmental performance and significantly impact the economics and site selection for power plant projects, particularly coal generation facilities. Environmental performance is a critical consideration in the development of new power generation facilities. Air pollutant emissions are the most prominent environmental issue associated with electricity generation. Other important considerations include water use and discharge and solid waste production. These environmental issues are discussed below along with the environmental performance of standard IGCC. The most problematic emissions include sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide. IGGC technology offers the potential for significantly improved air emissions performance for coal-fueled power plants to address many of the environmental concerns associated with coal generation. IGCC power plants achieve emissions reductions primarily through the syngas cleanup processes, which occur prior to combustion. This emissions control method is very different from directly fired power plants, which achieve virtually all emissions control through combustion and post combustion controls that treat exhaust gases. Because syngas has a greater concentration of pollutants, lower mass flow rate, and higher pressure than stack exhaust gas, emissions control through syngas cleanup is generally more cost effective than post combustion treatment to achieve the same or greater emissions reductions. In new IGCC plants, virtually all of the particulates, nitrogen and sulfur compounds, and much of the mercury, are removed from syngas before it is directed to the combustion turbine [Rosemberg et al, 2004].

Table A.6 - Comparison of environmental performance of different power technologies (Hg emissions are still not regulated)

	Traditional PC	Super Critical	Operating IGCC	Hypogen	NGCC
	kg/MWh	kg/MWh	kg/MWh	kg/MWh	kg/MWh
NOx	1.90	0.81	0.40	0.13	0.13
SOx	1.45	0.48	0.36	0.16	≈ 0
PM	0.23	0.12	0.10	0.02	≈ 0
Hg	no control system	80% control	no control system	95% control	≈ 0

As a result, the particulate matter, NOx, SO_2 and mercury emissions resulting from syngas combustion in the turbine are significantly lower than the emissions produced by direct combustion of coal in PC boilers. IGCC plants also lend themselves to additional (90%) cost effective mercury control through installation of mercury-specific syngas clean-up processes. Although in EU no mercury emission regulation exists yet (in March 2004, the European Commission issued a consultation document on mercury), it is important to foresee the presence of a mercury removal unit in the Hypogen plant.

Besides the reduction of these pollutants, the main environmental feature of Hypogen is the reduction of CO_2 emissions, through CO_2 capture and storage. An evaluation of this reduction is reported in the following, with reference to the plant configuration C.

In basic operation mode the plant is producing 259 MW of electricity and about 32,000 Nm^3/h of hydrogen. On a yearly base the plant produces 1,704 GWh and 18,920 tH_2.

CO_2 is separated from hydrogen, as well as H_2S, inside the plant, before the Combined Cycle section, but, since separation itself can not reach the ideal value of 100% the plant is still emitting a small share of CO_2.

To calculate "avoided CO_2", two options have been considered in this study:

1. Take as a reference for electricity production an equivalent 259 MW power generation plant (IGCC), with the same fuel, without CO_2 separation (45% efficiency). For Hydrogen production the reference plant is a steam reformer fuelled with natural gas, without CO_2 separation. This option is the most representative in the short-medium term, when few Hypogen plant will be realized.
2. Take into account the CO_2 emission factor for electricity production in Europe. For hydrogen production we assume the hypothesis that it is all consumed for transportation, thus avoiding "standard" emission factors for cars and busses.

   In this case it has been considered for power generation only electricity production from fossil fuels at 2010, assuming a value of 0.390 tCO_2/MWhe ["European Union Energy Outlook to 2020", pages 186-187].

   Ratio between cars and busses has been assumed 1:60, and figures for hydrogen consumption, driving ranges and CO_2 emissions have been drawn for present experience. In particular for CO_2 emission for bus a value of 1000 gCO_2/km has been assumed, while for cars a value of 140 gCO_2/km. The numbers of cars and busses are respectively 104,000 and 1,400.

Table A.7 reports the results for emitted, avoided and sequestered CO_2.

Hypogen emissions account mainly on the percentage of CO_2 that could not be captured and is around 0.182 $MtCO_2$/y.

To calculate the real "Avoided" CO_2 emissions in both options, Hypogen emissions have been subtracted from total emission for power generation and transportation (1.39 and 0,841 $MtCO_2/y$ respectively for options 1 and 2). Finally ratio between sequestered and avoided emission has been calculated.

Table A.7 – Emitted, avoided and sequestered CO_2 for Hypogen plant

	Option 1	Option 2
Emission for electricity production ($MtCO_2/y$)	*1.270*	*0.664*
Emission for hydrogen production/transportation ($MtCO_2/y$)	*0.120*	*0.177*
Total emissions for electricity and hydrogen production	1.390	0.841
Hypogen emissions ($MtCO_2/y$)	0.182	0.182
Total avoided CO_2 ($MtCO_2/y$)	1.208	0.659
Hypogen sequestered CO_2 ($MtCO_2/y$)	1.704	1.704
Hypogen ratio sequestered/avoided	1.492	2.586

4. Techno - Economic Analysis

Considering specific capital costs of 1909 €/kWe [David and Herzog, 2001] for an IGCC plant, (including CO_2 capture and compression up to 100 bar) and 130 €/Nm^3d (33 €/GJ-yr) for hydrogen plant [Brinkman, 2001; AA.VV., DOE, 2002], the total investment for the plant in case of electricity only production is about 487 M€ while in the co-production case is about 595 M€. With a coal price set to 1.18 €/GJ [Tzimas and Peteves, 2003], 25 years of plant life, 10% discount rate and 4% of total investment for O&M yearly costs (direct labour has been valued in 120-150 people at an average yearly cost equal to 50,000 € included in O&M costs), the expected cost of produced electricity (COE) and the hydrogen cost (COH) have been calculated. Extra costs for CO_2 transport and storage has been taken in account (3.93 €/t for transport and 2.14€/t for storage are average values for 100 km pipeline transport and medium depth wells as reported in previous chapters). Specific cost are constituted by fixed capital charge cost, operating and maintenance (O&M) and fuel costs. It has been assumed a fixed capital charge rate and other costs given by:

$$\text{Cap Costs} = \text{FCR} * \text{Total Plant Cost} = i\ /\ (1-(1+i)^{-n}) * \text{TPC} = 0.11 * \text{TPC}$$

$$\text{O\&M} = 4\% \text{ of Total Plant Cost}$$

$$\text{Fuel} = \text{Coal Specific Cost} * \text{Coal Consumption}$$

$$CO_2\ \text{T\&S} = (\text{Specific transport and storage cost}) * \text{Amount of } CO_2 \text{ captured}$$

For the A case the cost of electricity (COE) is given by the ratio between yearly electricity production and total yearly costs (Plant + O&M + Fuel Costs). In the B and C case (co-production), two different products are made available, the cost of the plant has been calculated as sum of the costs related to two plants that yield only a product (electricity or hydrogen). For the calculation of the specific costs only the "electrical part" of total plant cost has been considered for COE and only the "hydrogen part" of total plant cost for specific hydrogen production cost (COH). In the case B a higher specific capital cost has been considered to take in account the fact that the plant is the same as in case A but the efficiency is lower. For both cases O&M cost are fixed to 4% of plant cost while fuel cost are proportionally to coal input. Also CO_2 transport and storage cost have been considered.

Table A.8 - Assumption parameters and expected costs

Case		A	B	C
Size	MWe	255	192	259
Capital Cost	€/kWe - €/Nm^{3}d	1909	2020 / 130	1909 / 130
Total Plant Cost	M€	487*	487*	595
Plant Life	years	25	25	25
Discount Rate	%	10	10	10
Coal Cost	€/GJ - €/ton	1.18 - 29.5	1.18 - 29.5	1.18 - 29.5
Coal Supply	tpd	2,467*	2,467*	2,940
CO_2 Production	tpd	5,766	5,766	6,873
CO_2 Sequestered	tpd	5,222	5,222	6,225
O&M Costs	% of TPC	4	4	4
CO_2Transport/Storage Cost	€/ton	3.93 + 2.14	3.93 + 2.14	3.93 + 2.14
Electric Production	GWh/y	1,674	1,258	1,704
Net El. Efficiency	%	35,7	33,5	36,6
COE	€/kWh	0.0555	0.0589	0.0552
COE with CO_2 T&S	€/kWh	0.0613	0.0650	0.0608
Hydrogen Production	Nm3/d	-	768,854	768,854
COH	€/GJ - €/kWh	-	8.34 – 0.03	8.34 – 0.03
COH with CO_2 T&S	€/GJ - €/kWh	-	9.17 – 0.033	9.17 – 0.033

* in A and B cases the plant is the same. In case "B" because of different efficiencies the installed kWe is assumed to be more expensive.

Specific production costs are comparable with those of most recent studies on hydrogen production from coal gasification (Tab.A.9, Brinkman, 2003).

Table A.9 - Summary of literature hydrogen production costs from coal (Brinkman, 2003)
(Source: Brinkman, G., "Economics and Environmental Effects of Hydrogen Production Methods", Fall 2003.)

Source	C_{CAP} ($-yr/GJ)	C_{OM} ($/GJ)	Eff %	COH ($/GJ)*
Kirk-Othmer	33.02	3.27	57	8.97
Foster-Wheeler	28.37	-	-	na
Stiegel	22.17	-	66	na
Williams	29.04	2.98	77	7.70
Rutkowski	27.95	-	63	na
Mean	28.10	3.12	66	8.33

* with FCR at 11% and coal at 1.18 $/GJ and without CO_2 Transport and Storage.

As reported before, technological improvements in power generation and in carbon capture and storage can lower the specific cost of electricity and hydrogen production in the future. Capital investment can be lowered and efficiency increased. Maintaining the same fuel costs, decreasing capital costs and increasing efficiencies it is possible to estimate future costs of hydrogen and electricity production (Table A.10).

Table A.10 – Assumptions for performance and capital cost, with expected specific electricity and hydrogen production costs (2015)

		A2	B2	C2
Size	MWe	255	192	259
Assumed Capital Cost	€/kWe - €/Nm^3d	1750	1885 / 110	1750 / 110
Total Plant Cost	M€	446	446	538
Coal Supply	tpd	2,148	2,148	2,585
Assumed Net El. Efficiency	%	41	39	42
COE	€/kWh	0.0504	0.0540	0.0501
COE with CO_2 T&S	€/kWh	0.0553	0.0592	0.0550
COH	€/GJ - €/kWh	-	7.32 – 0.026	7.32 – 0.026
COH with CO_2 T&S	€/GJ - €/kWh	-	8.159 – 0.029	8.159 – 0.029

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