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Master Thesis

Techno-Economic Assessment of Carbon Capture and Sequestration Technologies in the Fossil Fuel-based Power Sector of the Global Energy-Economy System

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Abstract

In order to stabilize the ascending man-made CO_2 concentration in a most efficient and cost-effective way, the emission mitigation options should be assessed in a comprehensive way. The objective of this thesis is to assess the integration of carbon capture and sequestration (CCS), as one of the mitigation alternatives, to fossil fuel based power plants, which are responsible for almost one third of the anthropogenic CO_2 emissions. In line with this objective, three main fossil fuel-based power plant technologies, Pulverized Coal (PC), Integrated Gasification Combined Cycle (IGCC) and Natural Gas Combined Cycle (NGCC), are modeled, from an engineering point of view, without and with CCS using the modeling tool IECM. The model provides a framework to assess the techno-economics of the plants in question, thus delivering the corresponding data about emissions, costs and plant performance. The reference PC plant is assumed to contain a supercritical boiler and to produce 500 MW gross electrical output. IGCC is based on the GE (Texaco) quench gasifier. The combined cycle technologies utilize two GE 7FA gas turbines. In terms of CO_2 capture technology, the PC plant is once assessed with a post-combustion amine system and once using the oxyfuel technology. IGCC makes use of a shift reactor plus Selexol to enable the capturing of CO_2. For NGCC capture plant, a post-combustion amine system captures the CO_2. In addition to reducing CO_2 emissions, the power plants have to comply with the European large combustion plant regulation regarding the emissions of SO_2, NO_X and PM (Particulate Matter). All emission control equipments required to achieve emissions lower than emissions constraints are applied.

The thesis analyzes, in particular, the effect of variability of fuel type by introducing four different coals: Appalachian medium sulfur, Illinois # 6, Wyoming Powder River basin and North Dakota lignite. In addition to fuel type, uncertainty in performance factors i.e. capacity factor, scaling factors i.e. plant size and technical factors i.e. turbine inlet temperature is addressed and analyzed via Monte Carlo Analysis.

In order to assess the contribution of CCS in the portfolio of mitigation options, the results of the engineering modeling described above, are used for parameterization of these technologies in a wider context of the global hybrid model, *REMIND,* which comprises an energy system model and macroeconomic growth model with the main target of providing realistic assessment of mitigation strategies and associated welfare effects. Here two sorts of case studies have been carried out: Firstly, base case studies, in which all the available technologies (including CCS) are evaluated simultaneously under BAU (Business as Usual) and a Policy scenario with an exogenous constraint on the maximum annual emissions pathway that leads to stabilization of atmospheric CO_2 concentrations at 450ppm, thus addressing the contribution of each technology as matter of time and magnitude. In the base case study, each coal type is separately analyzed, thus emphasizing the effect of coal type, not just on the coal technologies, but also on the technology choice in the whole energy system and further on the resource usage. Secondly, sensitivity

studies, carried out using the SimEnv tool, indicate the effect of parameter variations on the model results.

Abstrakt

Die CO_2 -Abscheidung und Sequestrierung (CCS) kann insbesondere im Elektrizitäts-Sektor einen hohen Beitrag zur Reduzierung der antropogenen CO_2 Emissionen leisten. Welchen Anteil die CCS- Technologie im Rahmen einer kosteneffizienten Klimaschutzstrategie leisten soll, hängt von vielen Parametern ab. In der vorliegenden Arbeit wurde deshalb für die wichtigsten CCS-Technologien (PC, IGCC und NGCC), eine systematische energie- und techno- ökonomische Bewertung der Nützlichkeit dieser Emissionsreduktionstechnologien durchgeführt. Zu diesem Zweck wurden zwei Analysen durchgeführt: Erstens, eine Modellierung der Anlagen in IECM, die die techno-ökonomische Daten dieser Anlagen liefert.

Ein besonderer Wert wurde hierbei auf die Untersuchung des Einflusses verschiedener Kohlenarten auf die Ergebnisse gelegt. Andere unsichere Parametern wurden mit Hilfe der Monte Carlo Analyse evaluiert.

Um eine bessere Beurteilung zu ermöglichen, und die Strategie- Wahl zu vereinfachen, sind die Kraftwerke im zweiten Model, REMIND, mit den Ergebnissen des ersten Models parametrisiert. Hier sind die Anlagen im Kontext eines Energiesystem-Models bewertet worden, in dem alle Emissionsminderungs-Optionen vorhanden sind.

Darüber hinaus wurde der Einfluss verschiedener Kohlentypen auf den Elektrizitäts-Mix und den Ressourcenverbrauch analysiert. Eine ausgiebige Sensitivitätsanalyse, die mit Hilfe der SimEnv- Plattform durchgeführt wurde, rundet die Arbeit ab.

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This thesis is dedicated to my Grandmother.

Contents

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Abbreviations

AGR
Acid Gas Removal

ASU
Air Separation Unit

BAU
Business as Usual

CCS
Carbon Capture and Sequestration (Storage)

COE
Cost of Electricity

COS
Carbonyl Sulfide

DCC
Direct Contact Cooler

DEA
Di-Ethanol Amine

ECBM
Enhanced Coal Bed Methane recovery

ELV
Emission Limit Value

EOR
Enhanced Oil Recovery

ESM
Energy System Model

ESP
Electrostatic Precipitator or Precipitation

FCF
Fixed Charge Factor

FGD
Flue Gas Desulfurization

GHG
Greenhouse Gas

GT
Gas turbine

HHV
Higher Heating Value, kJ/kg

HRSG
Heat Recovery Steam Generator

IEA
International Energy Agency

IECM
Integrated Environmental Control Model
(Carnegie Mellon University)

IGCC
Integrated Gasification Combined Cycle

IGCCC
Integrated Gasification Combined Cycle with pre-combustion CCS

IPCC
Intergovernmental Panel on Climate Change

LCP
Large Combustion Plant

LHV
Lower Heating Value, kJ/kg

LNB
Low NO_X Burner

MCA
Monte Carlo Analysis

MDEA
Methyl-Diethanol Amine

MEA
Mono Ethanol Amine

MGM
Macroeconomic Growth Model

MIT
Massachusetts Institute of Technology

NETL
National Energy Technology Laboratory

NG
Natural Gas

NGCC
Natural Gas Combined Cycle

NGCCC
Natural Gas Combined Cycle with post combustion CCS

NLP
Non-linear Programming

NSPS
New Source Performance Standards

O&M
Operating and Maintenance Costs

PC
Pulverized Coal

PCC
Pulverized coal combustion with post combustion CCS

PCO
Pulverized coal combustion with oxyfuel CCS

PM
Particulate Matter

PRB
Powder River Basin

SCR
Selective Catalytic Reduction

SimEnv
Multi-Run Simulation Environment

SNCR
Selective Non-Catalytic Reduction

ST
Steam turbine

TCR
Total Capital required, $/kWe

UNFCCC
United Nations Framework Convention on Climate Change

Chapter 1: Introduction

1.1. Why CCS in fossil fuel based power plants

In order to achieve the main objective of the article 2 of UNFCCC (United Nations Framework Convention on Climate Change) namely "the stabilization of greenhouse gas concentrations in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system", several mitigation options including CO_2 capture and sequestration (CCS)[1] aim at constraining CO_2 emissions. CCS is one alternative in the portfolio of options for reducing greenhouse gas emissions that allows for the decreasing of atmospheric CO_2 emissions from relatively cheap fossil fuel-based power generation plants.

Approximately one third of all CO_2 emissions due to human activity come from fossil fuels used for generating electricity; with each power plant capable of emitting several million tonnes of CO_2 annually as stated by *IEA World Energy Outlook.* However, the importance of electricity in the whole energy system is emphasized by its growing share in the final energy consumption. Improving the energy efficiency and using alternative energy sources, like wind and solar power, are possible measures to reduce the anthropogenic emissions. However, capturing the carbon from the fossil fuel-fired power plants and storing it underground is getting more attention, as electricity will continue to be fossil fuel-based for the foreseeable future. Thus CCS enables the further usage of well-established technologies with almost the same base infrastructure and significantly lower CO_2 emissions. In addition, CCS enables the reduction of other pollutants like SO_X, NO_X, and particulate matters. Despite all the advantages, the drawbacks concerning CCS, calls the feasibility of the technology into question. Examples of these drawbacks are the missing regulations, health, safety and environmental risks of CCS and the question of public acceptance. In addition, CCS is a relatively energy-consuming and cost-intensive technology.

1.2. Thesis motivation and objectives

The objective of this thesis is to improve the understanding of the techno-economics of CCS in the power sector and its contribution to CO_2 mitigation within a portfolio of other mitigation options. In this regard, the thesis develops a framework to analyze the energy- and techno-economics of the three main fossil fuel power plants without and with CCS. This includes pulverized coal (PC) combustion plants, coal-based integrated gasification combined cycle (IGCC) plants, and the natural gas combined cycle (NGCC) plants. Six questions, which need to be addressed, include:

1. What are the major technical and economical factors that affect the performance and the cost of fossil fuel-based power plants systems with and without CO_2 capture and how are these power plants configured considering these factors?
2. To what extent are these systems sensitive to the variability of fuel types?
3. What are the key uncertain parameters associated with these systems and how do they influence the costs and performance of these power plants and further the application of CCS technologies and the costs of mitigating CO_2 emissions?

[1] In some literatures CCS is referred to as Carbon Capture and Storage.

4. What is the contribution of CCS to reduction of the other pollutant emissions?
5. How much does CCS contribute to CO_2 emission mitigation (question of time and quantity)?
6. How sensitive are these plants to certain parameters and to what extent can they affect the employment of different mitigation options (including CCS)?

1.3. Structure of the thesis

These objectives frame the structure of this thesis. Following the introduction in chapter 1, chapter 2 introduces briefly CCS technologies. In line with the thesis key questions, chapter 3 provides the know-how of the power plants and builds a basis for modeling in the next chapters. These data are based on a wide literature survey done on previous studies concerning CCS technologies and fossil fuel power plants, and also experts' opinions. The techno-economics of the power plants are conducted with two different concerns regarding the details and integration with other systems: firstly, the engineering analysis and secondly, the energy-economic analysis. The engineering analysis, carried out in chapter 4, encompasses the configuration of different types of power plant concepts at a high level of technological detail. This part of the thesis focuses on choosing the required unit operations with respect to fuel characteristics and multi-pollutant emission regulations. Further on, the design parameters of the unit operations, plant performance and economical assumptions will be set. This engineering analysis gives back essential information of the techno-economics of the power plants such as investment costs, O&M costs, plant efficiency, net plant output and emission coefficients. The results obtained from the model are in turn input for the energy-economics analysis, where CCS is one alternative within a portfolio of CO_2 mitigation options. This analysis can be found in detail in chapter 5. The energy-economic analysis draws conclusions on timing and the extent of using the CCS option within a framework of long-run economic growth. Importantly, the results of the energy-economic analysis depend on the outputs of the engineering analysis, since the latter delivers input data for the former. The information obtained from the engineering analysis is subject to uncertainty of technical and economical parameters as well as variability of natural conditions such as coal type. Consequently the results of the energy-economic analysis are conditional depending upon uncertainty and variability. The present thesis addresses uncertainty by introducing distribution functions for the input parameters of the engineering analysis. The results subsequently build a basis for sensitivity studies in the energy-economic analysis. Inclosing, the thesis expresses results on the timing and extent of CCS technology in consistence with deterministic and uncertain parameters of techno-economic analysis.

For processing the data and getting the results, two different models have been used: *IECM-s* and *REMIND.* Figure 1.1 gives a better understanding of the thesis procedure.

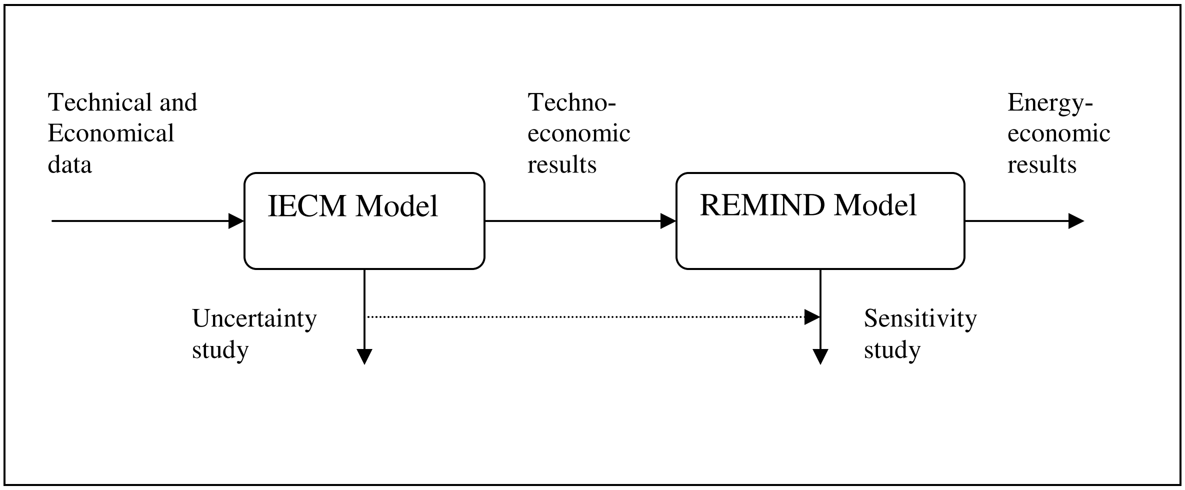

Figure 1.1: Schematic of the thesis procedure

IECM-s, Integrated Environmental Control Model with Carbon Sequestration developed for the U. S. Department of Energy's National Energy Technology Laboratory (NETL), has been used as modeling tool in engineering analysis. Here, a systematic evaluation has been performed for different power plant concepts. In addition, uncertainties have been explicitly characterized via Monte Carlo analysis in *IECM-s,* thus delivering the input parameters (either deterministic values or distribution functions) for the *REMIND* model.

REMIND is a global hybrid model, which is written in GAMS and developed by the Potsdam Institute for Climate Impact Research (PIK). The objective function maximizes macroeconomic welfare, taking into account various constraints e.g. the greenhouse gas emission constraint in policy scenarios. At the same time, the model gives the user the opportunity to assess the role of different mitigation options. Two kinds of case studies have been carried out in *REMIND*, base case studies and sensitivity studies. Experiments with *REMIND* provide a methodology to compare different technological options in terms of the cost and emissions taking into account the variability. The uncertainty results from *IECM-s* are finally considered to run the sensitivity analysis with SimEnv tool in the context of the entire energy system.

Chapter 2: CCS technologies

This part of the thesis provides a short description of CCS technologies. More details on the capture part of the single technologies are given in chapters 3 and 4. Most of the information presented here are from the IPCC special report on CCS and IEA (International Energy Agency) Greenhouse Gas R&D[2]. Please refer to references [1], [2] and [3] for additional information.

2.1. Brief description of CO_2 capture and storage

Anthropogenic CO_2 is emitted principally from the burning of fossil fuels, both in large combustion units such as those used for electric power generation and in smaller, distributed sources such as automobile engines and furnaces used in residential and commercial buildings. CO_2 emissions also result from some industrial and resource extraction processes, as well as from the burning of forests during land clearance [1]. The heavy worldwide reliance on fossil fuels today (approximately 80% of global energy use), the potential for CCS to reduce CO_2 emissions over the next century, and the compatibility of CCS systems with current energy infrastructures explain the interest in this technology.

CCS involves the use of technology, first to collect and concentrate the CO_2 produced in industrial and energy related sources, transport it to a suitable storage location, and then store it away from the atmosphere for a long period of time. CCS would thus allow fossil fuels to be used with low emissions of greenhouse gases [1].

The main steps of the CCS process are capture, transport, injection and sequestration. The capture step involves separating CO_2 from other gaseous products. The transport step may be required to carry captured CO_2 to a suitable storage site located at a distance from the CO_2 source. To facilitate both transport and storage, the captured CO_2 gas is typically compressed to a high density at the capture facility. Potential storage methods include injection into underground geological formations, injection into the deep ocean, or industrial fixation in inorganic carbonates [1]. It should be noted that the maturity of the CCS differs from technology to technology. Some are already commercially applied whereas some just in research phase.

The main focus of the CCS in this thesis is in the power plants. This is due to the fact that the fossil fuel power plants are responsible of emitting large amount of CO_2. According to IPCC report 2005 [1], 10539 Mt CO_2 per year is emitted from 4,942 fossil- fuel power sources, which amounts to 78% total worldwide CO_2 emissions.

2.2. Capture

The figure below gives an overview of CO_2 capture systems. Depending on the process or power plant application in question, there are three main approaches to capturing the CO_2 generated from the fossil fuel feed, namely coal and natural gas, to the power plant:

[2] Please refer to www.ieagreen.org.uk

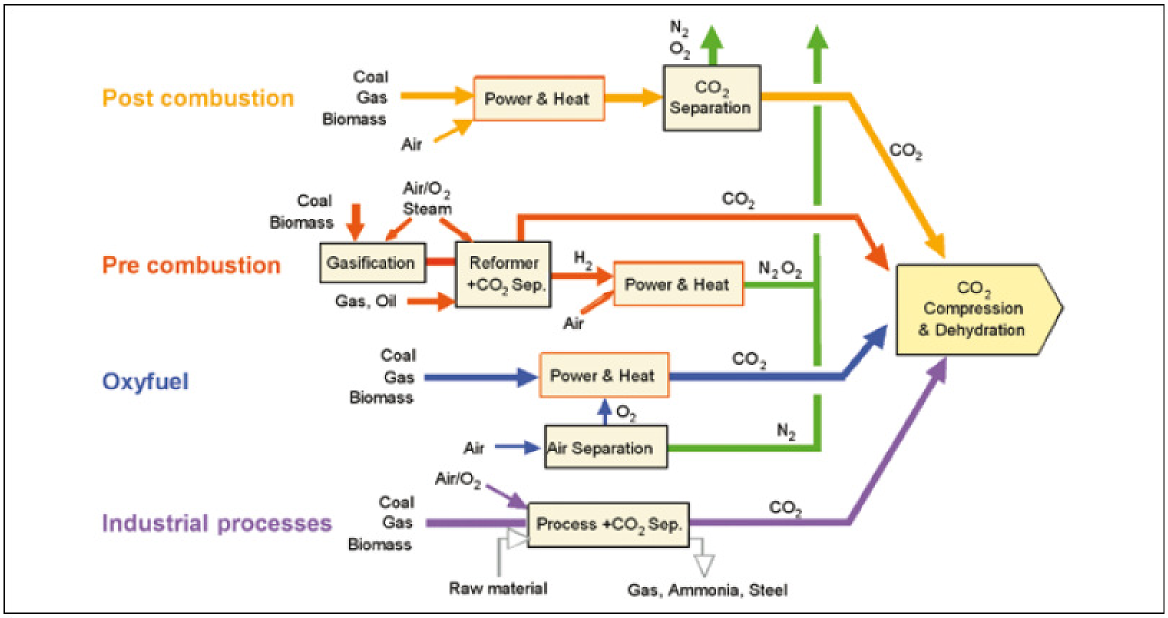

Figure 2.1: CO_2 Capture systems; Ref. IPCC

2.2.1 Post-combustion

Post-combustion systems separate CO_2 from the flue gases produced by the combustion of the primary fuel in air. These systems normally use a liquid solvent- mostly amines- to capture the small fraction of CO_2 present in the flue gas stream by a chemical reaction. The flue gas must contain very low levels of oxides of nitrogen and sulfur (NO_X and SO_2) to form stable, non- regenerable salts in reaction with the amine. This means that post-combustion CO_2 capture on coal fired power plants requires upstream de-NO_X and flue gas desulphurization (FGD) facilities. The solvent is then regenerated. For a modern pulverized coal (PC) power plant or a natural gas combined cycle (NGCC) power plant, current post-combustion capture systems would typically employ an organic solvent such as monoethanolamine (MEA) [1].

2.2.2 Pre-combustion

Pre-combustion systems process the primary fuel in a reactor with steam and air or oxygen to produce a mixture consisting mainly of carbon monoxide and hydrogen (synthesis gas). The reaction between the carbon monoxide with steam in a second reactor (a “shift reactor”) produces additional hydrogen and CO_2. The resulting mixture of hydrogen and CO_2 can then be separated into a CO_2 gas stream, and a stream of hydrogen. If the CO_2 is stored, the hydrogen is a carbon-free energy carrier that can be combusted to generate power and/or heat. Although the initial fuel conversion steps are more elaborate and costly than in post-combustion systems, the high concentrations of CO_2 produced by the shift reactor (typically 15 to 60% by volume on a dry basis) and the high pressures often encountered in these applications are more favorable for CO_2 separation. Pre-combustion can be used in natural gas or coal based plants that employ integrated gasification combined cycle (IGCC) technology [1].

2.2.3 Oxyfuel

Oxyfuel combustion systems use oxygen instead of air for combustion of the primary fuel to produce a flue gas that is mainly water vapor and CO_2. This results in a flue gas with high CO_2 concentrations. Cooling and compressing the gas stream then remove the water vapor. It may have potential as a part of a system for capturing and storing CO_2 as the nitrogen concentration in the flue gas is much lower than when air is used for firing. So the CO_2 can be stored with less downstream processing. Oxyfuel combustion systems are, in principle, able to capture nearly all of the CO_2 produced. However, the need for additional gas treatment systems to remove pollutants such as sulfur and nitrogen oxides lowers the level of CO_2 captured to slightly more than 90%.

The large amount of oxygen, which is required for combustion, is obtained from an air separation unit. Further treatment of the flue gas may be needed to remove air pollutants and non-condensed gases (such as nitrogen) from the flue gas before the CO_2 is sent to storage. As a method of CO_2 capture in boilers, oxyfuel combustion systems are in the demonstration phase. Oxyfuel systems are also being studied in gas turbine systems, but conceptual designs for such applications are still in the research phase [1].

Apart from power plants, CO_2 capture is already used in several industrial applications. A commercial example is CO_2 post-combustion capture at a plant in Malaysia. This plant employs a chemical absorption process to separate 0.2 $MtCO_2$ per year from the flue gas stream of a gas-fired power plant for urea production (Courtesy of Mitsubishi Heavy Industries). Another example is CO_2 pre-combustion capture at a coal gasification plant in North Dakota, USA. This plant employs a physical solvent process to separate 3.3 $MtCO_2$ per year from a gas stream to produce synthetic natural gas [1]. Employment of CO_2 capture for industrial application is beyond the scope of this thesis.

Table 2.1 provides a summary of available CCS technologies in combination with the relating fossil fuel.

	Pre-combustion	**Post-combustion**	**Oxyfuel**
Coal	IGCC-gasification	PC	PC
Natural Gas	NGCC- steam methane reforming	NGCC	NGCC

Table 2.1.: CCS technologies in combination with fossil fuels

Although this thesis focuses mainly on the capture part of CCS, a brief introduction of the next steps of CCS chain, namely transport and storage is given next.

2.3. Transport

Pipelines are the most common way of transporting CO_2. Gaseous CO_2 is typically compressed to a pressure above 8 MPa in order to avoid two-phase flow regimes and increase the density of the CO_2, thereby making it easier and less costly to transport. CO_2 can also be transported as a liquid in ships, road or rail tankers that carry CO_2 in insulated tanks at a temperature well below ambient, and at much lower pressures [1].

2.4. Storage

The captured CO_2 would need to be stored securely for hundreds or even thousands of years, in order to avoid it from reaching the atmosphere. The storage possibilities are: Geological storage, ocean storage and mineral carbonation. These options are in progress.

CO_2 captured from the plants (and other industrial processes), could stored underground using:

- Enhanced Oil Recovery (EOR)
- Gas or oil fields
- Saline formations
- Enhanced Coal Bed Methane recovery (ECBM).

CO_2 has been injected into oil fields to enhance recovery for many years. Due to IEA, for the first time, CO_2 is being deliberately stored in a salt-water reservoir under the North Sea for climate change reasons. The potential capacity for underground storage is large but not well documented. The assumptions in this regard depend highly on geological factors. Other geological storage schemes are under development and plans to monitor them are well advanced.

A potential CO_2 storage option is to inject captured CO_2 into the deep ocean (at depths greater than 1,000 m), where most of it would be isolated from the atmosphere for centuries. Ocean storage has not yet been deployed or demonstrated at a pilot scale, and is still in the research phase. However, there have been small-scale field experiments and 25 years of theoretical, laboratory and modeling studies of intentional ocean storage of CO_2. One should note that the injection of a few $GtCO_2$ would produce a measurable change in ocean chemistry in the region of injection, whereas the injection of hundreds of $GtCO_2$ may produce larger changes in the region of injection and eventually produce severe changes in the chemical conditions (such as pH) and biological environment over the entire ocean volume [1].

Mineral carbonation involves converting CO_2 to solid inorganic carbonates using chemical reactions. The extent to which mineral carbonation may be used cannot be determined at this time, since it depends on the unknown amount of silicate reserves that can be technically exploited, and issues such as assessments of the technical feasibility and corresponding energy requirements at large scales [1].

After this brief introduction to CCS and it applications, this thesis focuses mainly to CO_2 capture from fossil-fuel fired power plants and limits itself to geological CO_2 storage in the next chapters.

Chapter 3: Fossil fuel based power plants

As widely available around the world, fossil fuels are considered to play an important role in providing the world with energy. The objective of this chapter is to assess three types of power generating technologies, which are based on fossil fuel feed, with and without CO_2 capture; these include Pulverized Coal (PC), Integrated Gasification Combined Cycle (IGCC) and Natural Gas Combined Cycle (NGCC). Each technology is described once without and once with CCS. Special attention has been paid to the design of the plants, esp. with respect to the multi pollutants emission control; thus this chapter frames the basis for modeling in the next chapter. Most of the information, especially regarding the individual process description, is from ref. [4], [5] and [6].

3.1. Pulverized Coal (PC)

Pulverized coal technology (PC) is the oldest technology for thermal power generation worldwide. It can be used for boiler sizes up to and above 1000 MW_e. The principle of the coal-fired units is to produce electricity by burning coal in a boiler to heat water to produce steam. The steam, at tremendous pressure, flows into a turbine, which spins a generator to produce electricity. The steam is cooled, condensed back into water, and returned to the boiler to start the process again. To improve the environmental performance, a pulverized coal power plant requires flue gas cleaning to avoid SO_2 and NO_X emissions. The effort for flue gas cleaning depends on environmental regulations in combination with the coal quality [6]. For a conventional steam plant firing pulverized coal, additional equipments required for the process are:

- Coal handling
- Coal preparation including pulverizers
- Particulate removal equipment; typically electrostatic precipitator (ESP)
- Solid waste handling and disposal

The traditional coal fired power plant comprises two basic components: the first component is the furnace boiler designed to burn coal and capture the heat energy released using a system of circulating water and steam. In the furnace the combustion takes place. In the most common type of boiler, pulverized coal is injected with a stream of air into a furnace into continuous process through a burner. The coal burns, thus producing the preliminary carbon dioxide while incombustible mineral material (ash) falls to the bottom of the furnace where it can be removed. The second part of the system is a steam turbine generator, which converts the heat energy captured by the steam into electricity.

Pulverized coal boilers can be divided into two groups based on steam data: subcritical steam boilers where the live steam pressure and temperature are below the critical values, and supercritical steam boilers with the steam data above the critical values. The current trend is to increase the steam data in order to increase the plant efficiency [6]. Regarding CO_2 capture, a PC plant can be designed with CO_2 capture facility or without. A brief description of these technologies is as below:

3.1.1. PC without CO_2 capture

3.1.1.1. Subcritical operation

Subcritical operation refers to steam pressure and temperature below 22.0 MPa (~3200 psi) and about 550° C (1025° F) respectively. In a pulverized coal unit, the coal is ground to talcum-powder fineness, and injected through burners into the furnace with combustion air. The fine coal particles heat up rapidly, undergo pyrolysis and ignite. The bulk of the combustion air is then mixed into the flame to completely burn the coal char. Dry, saturated steam is generated in the furnace boiler tubes and is heated further in the superheater section of the furnace. This high-pressure, superheated steam drives the steam turbine coupled to an electric generator. The low-pressure steam exiting the steam turbine is condensed, and the condensate pumped back to the boiler for conversion into steam. The flue gas from the boiler passes through the flue gas clean-up units to remove particulates, SO_X, and NO_X. The flue gas exiting the clean-up section meets criteria pollutant permit requirements, typically contains 10–15% CO_2 and is essentially at atmospheric pressure. A simplified block diagram of a subcritical PC generating unit is shown in figure 3.1 [4].

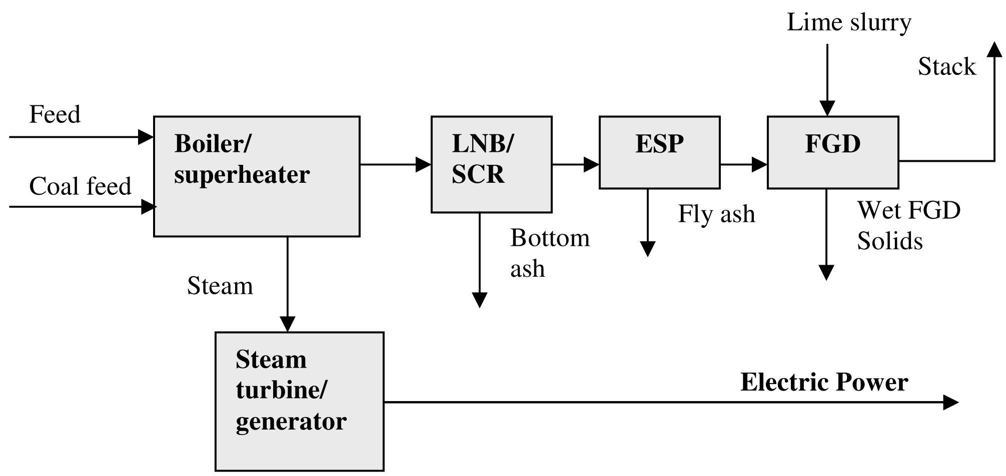

Figure 3.1: Pulverized coal unit without CO_2 capture

Subcritical PC units have generating efficiencies between 33 to 37% (HHV), dependent on coal quality, operations and design parameters, and location [4].

3.1.1.2. Supercritical operation

For the PC plants, the efficiency can be increased by operation at higher steam temperature and pressure. This represents a movement from subcritical to supercritical - and further to ultra- supercritical- steam parameters. Supercritical steam cycles were not commercialized until the late 1960s, after the necessary materials technologies had been developed. Under supercritical conditions, the supercritical fluid, namely steam, is expanded through the high-pressure stages of a steam turbine, generating electricity. Current state-of-the-art supercritical PC generation involves 24.3 MPa (~3530 psi) and 565° C (1050° F). To recharge the steam properties and increase the amount of power generated, after expansion through the high-pressure turbine stages, the steam is sent back to the boiler to be reheated. Reheat, single or double, increases the cycle efficiency by raising the mean temperature of heat addition to the cycle. The efficiencies of supercritical PC plants are higher than those of subcritical ones and range from 37 to 40% (HHV)[3], depending on design, operating parameters, and coal type [4]. Furthermore, the higher efficiency has major advantages such as reduced coal consumption and reduced emissions of NO_X, SO_2, particulates and waste per MWh_e produced [6]. The block diagram of a supercritical PC is the same as the subcritical one, just that the feed air and coal flow rates and the steam data will be different. Reference [4] have reported feed air flow rate of $245 x 10^4$ kg/hr and coal flow rate of $208 x 10^3$ kg/hr for 500 MW gross power generation under subcritical conditions whereas the corresponding flow rates could be reduced up to 20% by increasing the steam data.

Both sub- and supercritical PC boilers can be used for power plants up to 1000 MWe. Although the moderate steam data used in subcritical boilers result in rather low plant efficiencies, such boilers are fairly simple to operate and maintain, relative to other combustion technologies. The supercritical technology is more recent than subcritical. In the industrialized world, there are now many supercritical PC plants in operation, and most plants that are under construction will be also supercritical. However, both boilers can be used for any type of coal from bituminous to lignite, but a given boiler must be designed for one type of coal (e.g. lignite, bituminous). This means that once designed for a specific coal, the PC units are somewhat sensitive to changes in coal type.

3.1.2. PC with CO_2 capture

3.1.2.1. Post combustion

CO_2 capture with PC combustion generation involves CO_2 separation and recovery from the flue gas, at low concentration and low partial pressure. Of the possible approaches to separation, chemical absorption with amines, such as mono-ethanol amine (MEA), di-ethanol amine (DEA) and methyl di-ethanol amine (MDEA) or hindered amines is the commercial process of choice. Chemical absorption offers high capture efficiency and selectivity for air blown units and can be used with sub-, super-, and ultra-supercritical generation. Figure 3.2 illustrates the block diagram of a PC unit with CO_2 post-combustion capture. CO_2 is first captured from the flue gas stream by absorption into an amine solution in an absorption tower. The absorbed CO_2 must then be stripped from the amine solution via a temperature increase, regenerating the solution for recycle to the absorption tower. The

[3] The HHV of a fuel includes the heat recovered in condensing the water formed in combustion to liquid water. If the water is not condensed, less heat is recovered; and the value is the Lower Heating Value (LHV) of the fuel. The efficiency can be expressed either as LHV or HHV. The difference in efficiency between HHV and LHV for bituminous coal is about 2 percentage points absolute (5% relative), but for high-moisture sub-bituminous coals and lignite the difference is 3 to 4 percentage points [4].

recovered CO_2 is cooled, dried, and compressed to a supercritical fluid. It is then ready to be piped to storage [4], [7].

CO_2 removal from flue gas requires energy, primarily in the form of low-pressure steam for the regeneration of the amine solution. This reduces the amount of steam sent to the turbine and hence the net power output of the plant. Thus, to maintain constant net power generation the coal input must be increased, as well as the size of the boiler, the steam turbine/generator, and the equipment for flue gas clean-up, etc.; therefore, addition of CO_2 capture will result in an increase in plant size. Absorption solutions that have high CO_2 binding energy are required by the low concentration of CO_2 in the flue gas, and the energy requirements for regeneration are high [4]. According to a research report of the German Federal Ministry of Economics and Technology [8], using MEA requires energy of 4 MJ/kg captured CO_2. This thermal energy required to recover CO_2 from the amine solution and the required energy to compress CO_2 from 0.1 MPa to about 15 MPa would cause a decrease in plant efficiency.

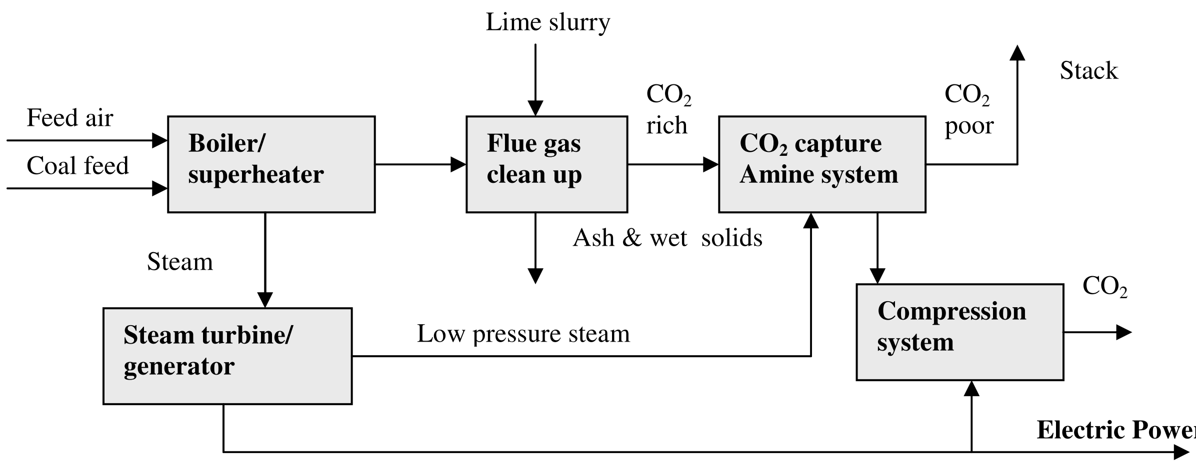

Figure 3.2: Pulverized coal unit with CO_2 capture

3.1.2.2. Oxyfuel pulverized coal combustion

The large amount of nitrogen introduced with the combustion air causes the major problems with CO_2 capture from the air-blown PC combustion. Another approach to CO_2 capture is to substitute oxygen for air, essentially removing most of the nitrogen. This approach to capturing CO_2 from PC units involves burning the coal with almost 95% pure oxygen instead of air as the oxidant. The flue gas then consists mainly of carbon dioxide and water vapor. Because of the low concentration of nitrogen in the oxidant gas (95% oxygen), large quantities of flue gas are recycled to maintain design temperatures and required heat fluxes in the boiler, and dry coal-ash conditions. The water is then easily removed, leaving a concentrated CO_2 stream for disposal. Oxyfuel enables capture of CO_2 by direct compression of the flue gas but requires an air-separation unit (ASU) to supply the oxygen. The high electricity requirement of the ASU causes reduction in efficiency.

A key unresolved issue regarding oxyfuel concept is the purity requirements of the supercritical CO_2 stream for geological injection (sequestration) [4]. High purity will cause additional costs.

Figure 3.3 shows an oxyfuel-generating unit with supercritical boiler and steam cycle.

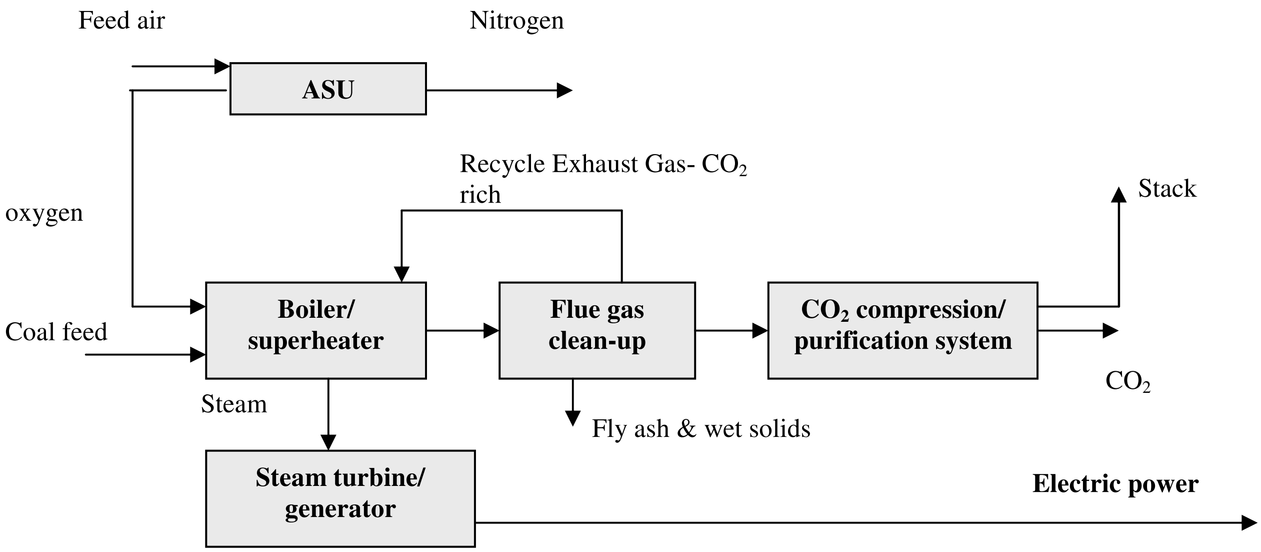

Figure 3.3: Oxyfuel combustion with CO_2 capture

3.1.3. Effect of coal type on PC plants

Coal composition, structure, and properties differ considerably among mining locations. Coal type and properties may impact the power plant design in terms of choice of suitable unit operations and their design parameters and thus affect the parameters such as efficiency, carbon dioxide and other multi-pollutant emissions, capital costs and cost of electricity.

The energy, carbon, moisture, and sulfur contents, as well as ash characteristics, all play an important role in the value and selection of coal, in its transportation cost, and in the technology choice for power generation. Most of the energy content in coal is associated with the carbon present. Higher-carbon coals normally have high energy content, are more valued in the market place, and are more suited for PC power generation [4]. On the other hand, it should be noted that low rank coals are also highly available worldwide. Due to IEA, lignite makes up approximately 17% world coal reserves whereas sub-bituminous makes up another 30%. Table 3.1 provides the typical properties of the characteristic coal types.

Coal type	Av. Energy content kJ/kg	Carbon content, wt%[4]	Moisture, wt%	Sulfur, wt%	Ash, wt%
Bituminous	27,900	67%	3-13	2-4	7-14
Sub- bituminous	20,000	49%	28-30	0.3- 0.5	5-6
Lignite	15,000	40%	30-34	0.6-1.6	7-16

Table 3.1: Properties of characteristic coal classes [4]

Using any of these coal types will significantly influence the design and configuration of the PC plant, and subsequently the costs, efficiency and the emissions. In general, higher sulfur content reduces PC generating efficiency due to the added energy consumption and operating costs to remove SO_X from the flue gas, which can otherwise cause corrosion. High ash content requires PC design changes to manage erosion [4]. Due to MIT, which compared different coals in PC plants, using bituminous Appalachian medium sulfur as the reference, PC units designed for Powder River Basin (PRB) coal and for Texas lignite have an estimated 14% and 24% higher capital cost respectively. Generating efficiency decreases but by a smaller percentage. However, the lower cost of coal types with lower heating value can offset the impact of this increased capital cost and decreased efficiency, thus, resulting in very little impact on COE. It should be noted that several ultra-supercritical and supercritical PC generating units with high efficiency have recently been commissioned in Germany burning brown coal or lignite.

3.1.4. Emission control for pulverized coal combustion[5]

When talking about the emissions, one should keep in mind that besides CO_2, other pollutants such as particulate matters, SO_2, NO_X, etc., are also of great importance. In addition to air pollution problem, the CO_2 capture requires low amount of SO_2 and NO_X in flue gas. These emissions are dependant on the coal quality used and respectively the unit operations applied to control them.

3.1.4.1. Particulate control

Particulate control is typically accomplished with electrostatic precipitators (ESP) or fabric filters. Either hot-side or cold-side ESPs or fabric filters are installed and achieve more than 99% particulate removal. The level of control is affected by coal type, sulfur content, and ash properties. Greater particulate control is possible with enhanced performance units or with the addition of wet ESP after FGD.

3.1.4.2. SO_X control

Partial flue gas desulphurization (FGD) can be accomplished by dry injection of limestone into the duct work just behind the air preheater (50-70% removal), with recovery of the solids in the ESP. On PC units wet flue gas desulphurization (FGD) (wet lime scrubbing), can achieve 95% SO_X removal without additives and 99+% SO_X removal with additives. Wet FGD has the greatest share of the market in the U.S. (when applied), is a proven technology, and is commercially well-established.

[4] wt% is weight percentage.
[5] The information below is collected from the study of MIT (Massachusetts Institute of Technology). Please refer to Ref. [4] for more details.

3.1.4.3. NO_X control

Low- NO_X combustion technologies (e.g. LNB), which are very low in costs, are always applied and achieve up to a 50% reduction in NO_X emissions compared to uncontrolled combustion. The most effective, but also, the most expensive, technology is Selective Catalytic Reduction (SCR), which can achieve 90% NO_X reduction over inlet concentration. Selective non-catalytic reduction falls between these two in effectiveness and cost. Today, SCR is the technology of choice to meet very low NO_X levels. The level of NO_X reduction depends on coal sulfur level.

3.1.4.4. Mercury control

Mercury in the flue gas is in the elemental and oxidized forms, both in the vapor, and as mercury that has reacted with the fly ash. This third form is removed with the fly ash, resulting in 10 to 30% removal for bituminous coals but less than 10% for sub-bituminous coals and lignite. The oxidized form of mercury is effectively removed by wet FGD scrubbing, resulting in 40-60% total mercury removal for bituminous coals and less than 30–40% total mercury removal for sub-bituminous coals and lignite. For low-sulfur sub-bituminous coals and particularly lignite, most of the mercury is in the elemental form, which is not removed by wet FGD scrubbing. In most tests of bituminous coals, SCR, for NO_X control converted 85-95% of the elemental mercury to the oxidized form, which is then removed by FGD. With sub-bituminous coals, the amount of oxidized mercury remained low even with addition of an SCR. Additional mercury removal can be achieved by activated carbon injection and an added fiber filter to collect the carbon. This can achieve up to 85-95% removal of the mercury. Commercial short-duration tests with powdered, activated carbon injection have shown removal rates around 90% for bituminous coals but lower for sub-bituminous coals.

3.1.4.5. Solid waste management

Coal combustion waste consists primarily of fly ash, along with boiler bottom ash, scrubber sludge, and various liquid wastes. This waste contains such contaminants as arsenic, mercury, chromium, lead, selenium, cadmium, and boron. These toxic contaminants can leach from the waste into groundwater and surface water when the waste is not properly disposed. Safe disposal of coal combustion waste requires placement in an engineered landfill with sufficient safeguards, including a liner, leachate collection system, groundwater monitoring system and adequate daily cover.

3.2. Integrated Gasification Combined Cycle (IGCC)

IGCC is an innovative electric power generation system that combines modern coal gasification technologies with both gas turbine (Brayton cycle) and steam turbine (Rankine cycle) technologies. Usually two third of the electricity is produced via the gas turbine and one third via the steam turbine. Since 1990 four commercial IGCC power plants are in operation. These power plants are located in Buggenum (NL), Puertollano (ES), Tampa (USA) and Wabash River (USA) [8]. According to reference [4], four 275 to 300 MWe coal-based IGCC demonstration plants, which are all in commercial operation, have been built in the U.S. and in Europe, each with government financial support. Five large IGCC units (250 to 550 MWe) are operating in refineries gasifying asphalt and refinery wastes; a smaller one (180 MWe) is operating on petroleum coke. The motivation for pursuing IGCC is the potential for high environmental performance at a lower electricity generation costs, easier CO_2 capture for sequestration, and higher efficiency correspondingly. In addition, the multi-pollutant emissions control is easier due to the clean-up in producing the syngas. However, the projected capital cost and operational availability of today's IGCC technology make it difficult to compete with conventional PC units at this time.

3.2.1. IGCC Process description

The first part of the IGCC process involves the chemical conversion of coal into syngas, a mixture of mostly hydrogen and carbon monoxide. This conversion is carried out in a gasifier, using very high temperature and only a limited amount of oxygen. When the syngas leaves the gasifier, it must be cleaned of any particulates and other contaminants such as sulfur, so that it can be used as a fuel for a gas turbine, which turns an electric generator to produce electric power. In addition, the hot exhaust gas from the gas turbine flows into a heat recovery steam generator (HRSG) for steam production, which turns a steam turbine that drives another electric generator to generate power. This combined cycle technology is similar to the technology used in modern natural gas fired combined-cycle power plants [5].

3.2.2. IGCC major components[6]

The major components of IGCC power plants, as shown in Figure 3.4, include the coal handling facility, gasifier, air separation unit, syngas cooling process, syngas cleanup processes, and the combined cycle power block.

Coal handling facility[7]: The coal handling facility is employed to unload, convey, prepare store and feed coal delivered to an IGCC power plant.

Gasification technology and gasifier: The gasification process is the heart of an IGCC plant. The process is a partial oxidation process which converts many carbon-based fuels, including most grades of coal, into a synthesis gas (syngas). Gasification reactions include reaction of water with coal char and reaction between water and carbon monoxide.

$$C + H_2O \rightarrow H_2 + CO$$

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

According to the coal movement and coal/gas contact pattern in the gasifier, gasification technologies can be classified into three types of moving bed, fluidized bed and entrained flow bed. Table 3.2 illustrates the major characteristics of these gasifier types.

[6] This part is a collection from ref. [5]
[7] This facility is not considered in the modeling in the next chapters.

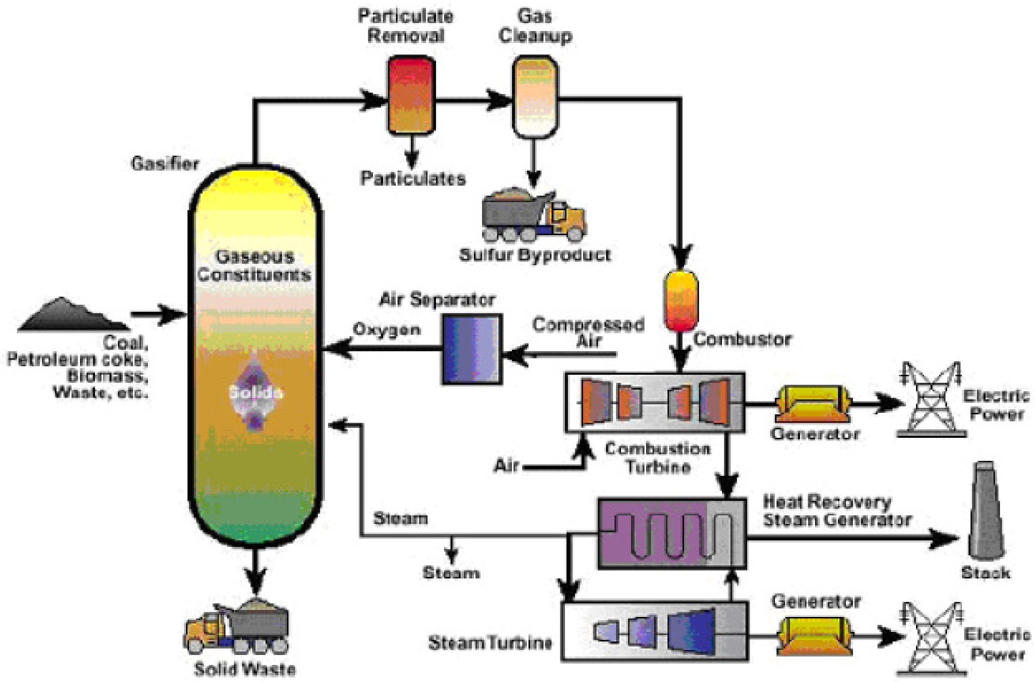

Figure 3.4: IGCC overall plant [Brown, 2003]

Operating temperature for different gasifiers is largely dictated by the ash properties of the coal. Depending on the gasifier, it is desirable either to remove the ash dry at lower temperatures (non-slagging gasifiers) or as a low-viscosity liquid at high temperatures (slagging gasifiers). For all gasifiers it is essential to avoid soft ash particles, which stick together and stick to process equipment, terminating operation [4].

Gasifier type	**Moving bed**	**Fluid bed**	**Entrained flow**
Outlet temperature	Low (425–600 °C)	Moderate (900–1050 °C)	High (1250–1600 °C)
Oxidant demand	Low	Moderate	High
Ash conditions	Dry ash or slagging	Dry ash or agglomerating	Slagging
Size of coal feed	6–50 mm	6–10 mm	< 100 µm
Acceptability of fines	Limited	Good	Unlimited
Other characteristics	Methane, tars and oils present in syngas	Low carbon conversion	Pure syngas, high carbon conversion

Table 3.2: Characteristics of Different Gasifier Types [4]

In moving-bed gasifiers, gas and solid contact in the pattern of counter flow, where large particles of coal move slowly down through the gasifier and react with gases moving up through it. For a fluidized-bed gasifier, coal is typically supplied through one side of the reactor, and oxidant and steam are supplied near the bottom. Fluidized bed gasifiers are best suited to relatively reactive fuels, such as biomass. In an entrained-flow gasifier, fine coal particles react with steam and oxygen at high temperatures. Entrained-flow gasifiers have the ability to gasify all coals regardless of rank.

The four major commercial gasification technologies are (in order of decreasing installed capacity):
1. Sasol-Lurgi: dry ash, moving bed (developed by Lurgi, improved by Sasol)
2. GE: slagging, entrained flow, slurry feed, single stage (developed by Texaco)
3. Shell: slagging, entrained flow, dry feed, single stage
4. ConocoPhillips E-Gas: slagging, entrained flow, slurry feed, two-stage (developed by Dow Chemical) [4]

There is an extensive commercial experience with the Sasol-Lurgi gasifier at Sasol's synfuel plants in South Africa. It is a moving-bed, non-slagging gasifier. The other three are entrained-flow, slagging gasifiers. Significant commercial experience with the GE/Texaco and Shell gasifiers is available, whereas less commercial experience with ConocoPhillips E-Gas technology exists so far [4]. Nearly all commercial IGCC systems in operation or under construction are based on entrained-flow gasifiers. Commercial entrained-flow gasifier systems are available from GE Energy Gasification Technology (formerly ChevronTexaco), ConocoPhillips, Shell, Prenflo, and Noell [Rosenberg, 2004]. High-pressure operation is favored for these units. The introduction of coal into a pressurized gasifier can be done either as dry coal feed through lock hoppers, or by slurrying the finely ground coal with water and spraying it into the gasifier. Sell gasifier represents a dry feed gasifier with syngas heat recovery whereas GE gasifier is a typical representative of slurry feed gasifier with full water quench. The latter does not accommodate heat removal. However, a radiant syngas cooler can be added to recover heat as high-pressure steam, which is used to generate electricity in the steam turbine. In addition, GE/quench design is the least cost method of providing moisture to syngas for shift reaction when carbon capture is applied. In the Shell gasifier, gasification and radiant heat removal are integrated into a single vessel. The membrane wall of the Shell gasifier, which becomes coated with a stable slag layer, recovers radiant heat energy via water filled boiler tubes. Shell gasfier has capability for higher throughput by addition of more fuel injectors. The choice of gasifier type at this point depends mostly on the type of coal fed to it. In general, the slurry feed gasifier introduces about 30 wt% liquid water, which is desirable for the gasification reactions if the coal has low moisture content. For high-moisture coals the gasifier feed can approach 50% water which increases the oxygen required to gasify the coal and vaporize the water, and reduces the operating efficiency due to reduced energy density of the slurry. High-ash coals have somewhat the same issues as high-moisture coals, in that heating and melting the ash consumes considerable energy, decreasing the overall operating efficiency [4]. Therefore GE design emphasizes on bituminous coals & petroleum coke [9]. Figure 3.5 shows a schematic of the GE- Texaco gasifier.
For high-moisture coals, a dry-feed gasifier such as Shell gasifier is more desirable. Shell gasifier can handle all coals including petroleum coke, bituminous, sub-bituminous coals and lignite, but its current design with syngas cooler and gas recycle

is expensive [9]. On the other hand, the dry feed gasifier needs pre-drying (e.g. to 5% moisture) of the feed.

Air separation unit (ASU): All coal gasification processes require an oxidant for the gasification reactions. The choice of oxidant affects the amount of nitrogen the gasification system has to handle, and depends on the application, types of gasifiers, and the degree of the system integration. Air-blown gasification eliminates the need for the ASU. Oxygen-blown IGCC systems, however, have several advantages over air-blown IGCC systems. Comparing to oxygen-blown gasification, air-blown gasification creates additional technical challenges for the gas clean up and combustion turbine operation. Air-blown gasification is also less suited for cost effective separation and capture of CO_2 due to the diluted CO_2 by nitrogen. For these reasons, the next generation of IGCC facilities are expected to be based on entrained-flow, oxygen-blown gasification technologies.

Syngas cooling process: The hot raw syngas from the gasifier has to be cooled down for cleanup. One option is to use full water quench process which uses water to cool the syngas. Although resulting in heat losses, the quench process has the advantage regarding the investment costs. Another method is to mix the syngas with recycled syngas, which has already been cooled and use syngas cooler for heat recovery (steam generation), which increases overall system efficiency [10].

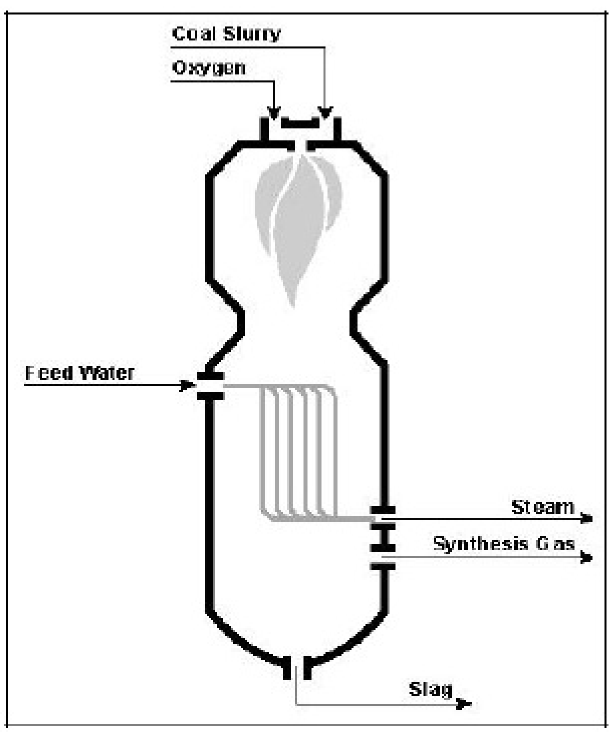

Figure 3.5: Texaco gasifier [Brown, 2003]

Syngas cleanup processes: The primary feedstock impurities of concern are the sulfur and ash constituents. Particulate removal is generally accomplished by cooling the syngas to much lower temperatures, and then using conventional cleaning methods including cyclones or water scrubbers. Next the syngas is treated in “cold-gas” clean up processes, also known as the Acid Gas Recovery (AGR) process, to remove most of the H_2S, carbonyl sulfide (COS) and nitrogen compounds. The primary processes are chemical solvent-based processes or physical solvent-based processes. Carbonyl sulfide (COS) is difficult to remove in AGR units, Therefore, further sulfur removal may be accomplished by the addition of a COS hydrolysis unit (before the AGR), which catalytically converts COS to H_2S.

Combined cycle power block: The clean syngas is sent to the combined cycle power unit. The gas mixture consists mainly of CO and H_2 when no capture is applied. By applying CO_2 capture, the gas consists of mainly H_2. In a combined cycle system, the first generation cycle involves the combustion of syngas in a combustion turbine. The gas turbine powers an electric generator, and the hot exhaust gases from the gas turbine, generally about 593°C (1100°F), are directed to a heat recovery steam generator (HRSG) which produces superheated steam for a steam turbine by cooling the combustion turbine flue gas; thus resulting in additional power through a steam cycle. Historically, natural gas has been the primary fuel for gas turbines.

3.2.3. IGCC without CO_2 capture

A block diagram of an IGCC unit using a radiant cooling/quench gasifier is shown in figure 3.6. Finely ground coal, either dry or slurried with water, is introduced into the gasifier, which is operated at pressures between 3.0 and 7.1 MPa (440 to 1050 psi), along with oxygen and water. Oxygen is supplied by an air separation unit (ASU). The coal is partially oxidized raising the temperature to between 1340 and 1400 °C. This assures complete carbon conversion by rapid reaction with steam to form an equilibrium gas mixture that is largely hydrogen and carbon monoxide (syngas). At this temperature, the coal mineral matter melts to form a free-flowing slag. The raw syngas exits the gasification unit at pressure and relatively high temperature, with radiative heat recovery raising high-pressure steam. Adequate technology does not exist to clean-up the raw syngas at high temperature. Instead, proven technologies for gas clean-up require near-ambient temperature. Thus, the raw syngas leaving the gasifier can be quenched by injecting water, or a radiant cooler and/or a fire-tube (convective) heat exchanger may be used to cool it to the required temperature for removal of particulate matter and sulfur. The clean syngas is then burned in the combustion turbine. The hot turbine exhaust gas is used to raise additional steam which is sent to the steam turbine in the combined-cycle power block for electricity production. For the configuration shown, the overall generating efficiency is about 38.4% (HHV) for high rank coals, but coal and gasifier type will alter value [4].

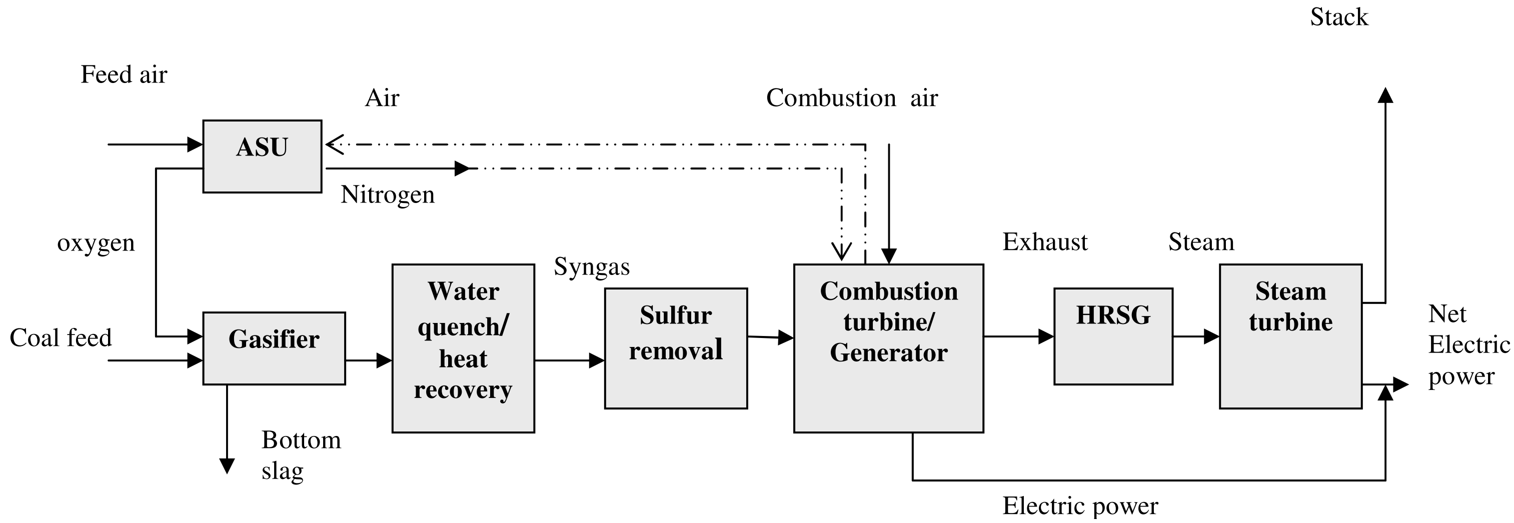

Figure 3.6: IGCC plant without CO_2 capture

3.2.4. IGCC with CO_2 capture

For capturing CO_2 from IGCC, the pre-combustion technology is used. Applying CO_2 capture to IGCC requires three additional process units: shift reactors, an additional CO_2 separation process, and CO_2 compression and drying. In the shift reactors, CO in the syngas is reacted with steam over a catalyst to produce CO_2 and hydrogen. Because the gas stream is at high pressure and has a high CO_2 concentration, a weakly CO_2- binding physical solvent, such as the glymes in Selexol, can be used to separate out the CO_2. Reducing the pressure releases the CO_2 and regenerates the solvent, greatly reducing the energy requirements for CO_2 capture and recovery compared to the MEA system. Higher pressure in the gasifier improves the energy efficiency of both the separation and CO_2 compression steps. The gas stream to the turbine is now predominantly hydrogen, which requires turbine modifications for efficient operation. The block diagram for an IGCC unit designed for CO_2 capture is shown in figure 3.7. For CO_2 capture, a full-quench gasifier is currently considered the optimum configuration. The overall generating efficiency shows reduction from the IGCC system without CO_2 capture. Adding CO_2 capture also means an increase in the coal feed rate [4].

As obvious from figure 3.7, a water gas shift reactor is added to the capture plant compared to the non-capture plant, to increase CO_2 partial pressure through converting CO into CO_2. CO_2 is then captured in a Selexol process. Water gas shift reaction is used to adjust the H_2 to CO ratio to the value required by the synthesis reaction to follow.

$$CO + H_2O \longrightarrow CO_2 + H_2$$

Because the shift reaction is exothermic, there is high quality energy available for generating high pressure and intermediate pressure steam during the syngas cooling process.

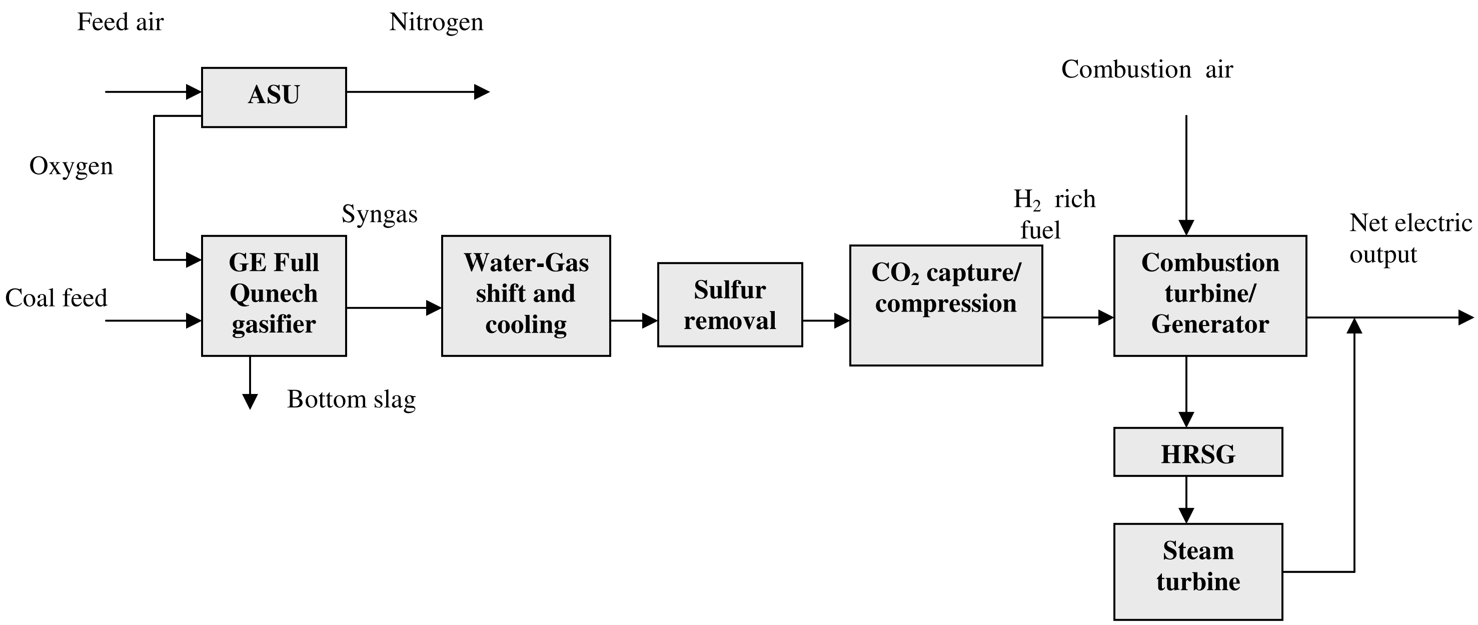

Figure 3.7: IGCC plant with CO_2 capture

3.2.5. Effect of coal type on IGCC plants

The coal characteristics affect the IGCC more than PC generation. The impacts are mostly on capital costs and efficiency. For a GE (Texaco) gasifier, coal is prepared in a slurry form. The composition of the slurry, for a given type of coal and the water percentage in the slurry by weight, may influence the gasifier efficiency and the efficiency of a whole IGCC power plant [5]. The lower the energy density of the slurry feed, the higher is the energy requirement to heat up the feed and vaporize water [10]. Regarding the coal type, the sulfur content is not so problematic comparing PC. It just affects the size of the sulfur clean-up process. The ash content can, on the other hand, cause a reduction in efficiency because more energy is required for melting it.

3.2.6. Emission control for IGCC[8]

It should be noted that IGCC has advantages regarding the emissions control over PC. Criteria emissions control is easier due to the clean-up process in the syngas, thus making removal more effective.

[8] The information below is collected from the study of MIT (Massachusetts Institute of Technology). Please refer to Ref. [4] for more details.

3.2.6.1. Particulate control

Most of these emissions come from the cooling towers, and not from the turbine exhaust, and are characteristic of any generating unit with large cooling towers. This means that particulate emissions in the stack gas are below 0.001 lb/MBtu or about 1 mg/Nm^3.

3.2.6.2. SO_X control

Commercial processes such as MDEA and Selexol can remove more than 99% of the sulfur so that the syngas has a concentration of sulfur compounds that is less than 5 ppmv. Recovered sulfur can be converted to elemental sulfur or sulfuric acid and sold as by-product. Current IGCC permit applications have sulfur emissions rates of between 0.02 and 0.03 lb SO_2/million Btu.

3.2.6.3. NO_X control

Dilution of syngas with nitrogen and water is used to reduce flame temperature and to lower NO_X formation to below 15 ppm. Further reduction to single digit levels can be achieved with SCR. Current IGCC permit applications are at the 0.06 to 0.09 lb NO_X /million Btu.

3.2.6.4. Mercury control

Commercial technology for mercury removal in carbon beds is available.
For syngas processing, 95% removal has been demonstrated. Mercury and other toxics, which are also captured in both the syngas clean-up system (partial capture) and carbon beds produces a small volume of material, which must be handled as a hazardous waste.

3.2.6.5. Solid waste management

IGCC process differences result in significantly different solid waste streams than are produced by a PC. For the same coal feed an IGCC produces 40% to 50% less solid waste than a PC plant. An IGCC plant produces three types of solid waste, namely ash (typically as a dense slag), elemental sulfur (as a solid or a liquid), and small volumes of solid captured by process equipment. Sulfur, as H_2S in the syngas, can be recovered either as elemental sulfur (solid or liquid) or as sulfuric acid, which can be sold as a by-product.

3.3. Natural Gas Combined Cycle (NGCC)

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the gas turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion based technologies. Combined-cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis) [11].

3.3.1. NGCC without CO_2 capture

In an NGCC, air is first compressed and fed to the natural gas combustion chamber. The pressurized hot combustion gases are then expanded in a number of stages in a gas turbine (GT) to produce work, which is converted to electricity by the generator. In this way, the GT off-gas loses its pressure, but not all of its heat, retaining a typical temperature around 500°C. This heat is used to produce superheated high-pressure steam in a heat recovery steam generator (HRSG). This steam is then expanded in the steam turbine (ST). The efficiency of a simple cycle in state-of-the-art GTs ranges from 34% to 39% LHV, whereas combined cycles based on the same turbines have efficiencies ranging at present from 55% to 58% LHV. The efficiency of the NGCC is largely dependent on the temperature and pressure of the gas entering the gas turbine. State-of-the-art power cycles have a combustion temperature of 1475 °C (Matta et al., 2000). These temperatures are constrained by both the construction material characteristics and the formation of more NO_X at higher temperatures. The introduction of new materials and new firing technologies is required to allow temperatures up to 1850 °C (Rao et al., 2002). Other main development item for efficiency improvements, in addition to increasing the combustion temperature, is pressure increase in the GT and the ST [12].

A single-train combined-cycle plant consists of one gas turbine generator, a heat recovery steam generator (HSRG) and a steam turbine generator. The most common technology in use for large combined-cycle plants is "FA-class" combustion turbine. Increasingly common are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple combustion turbines provide improved part-load efficiency. Other plant components include cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities [9][11].

3.3.2. NGCC with CO_2 capture

Capturing CO_2 from NGCC power plant is possible via pre-combustion (steam methane reforming), post- combustion and oxyfuel technology. Among these CCS options, performance of post-combustion CO_2 absorption in combination with a natural gas combined cycle (NGCC) has been described due to advanced state of development of amine absorption. Oxy-combustion is at a relatively early stage of development.

Post- combustion capture normally uses a solvent to capture CO_2 from the flue gas of the power plant. The solvent is then regenerated. It is based on the reversible character of the reaction of CO_2 and other acid gases with alkaline absorbents. As already stated in the PC with post-combustion capture, the absorbents used are usually amine solvents (taking into account that CO_2 partial pressure is low in the flue gas, and the amines are less dependent on partial pressure). The flue gas of a power cycle needs to be cooled before it is brought into contact with the solvent. The flue

[9] Additional peaking capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing (direct combustion of natural gas in the heat recovery steam generator) [11]

gas is pumped through an absorption column where the CO_2 binds to the absorbent at temperatures between 40 and 60 °C. The flue gas is then washed to remove water and solvent droplets/vapor. The CO_2-rich solvent is subsequently transferred to the top of a stripper column. In this column, heat is used to free the CO_2. The regeneration of the solvent takes place at a temperature between 100 and 140 °C. This heat is generated in a reboiler from steam extracted from the power cycle. The pressure of the regeneration process is nearly atmospheric. The gas stream from the stripper is a CO_2/H_2O mixture. The steam is recovered by a condenser, after which the CO_2 is pressurized for transport. Heat from the CO_2-lean solvent is then transferred to the CO_2-rich solvent in a heat exchanger [12]. The process flow diagram is shown in figure 3.8.

The absorption characteristics of the solvent are very determining for the energy use, capital costs, and O&M costs of the capture process. The most important characteristics are the chemical binding energy, the absorption rate, the solvent loading, and absorption and desorption temperatures [12].

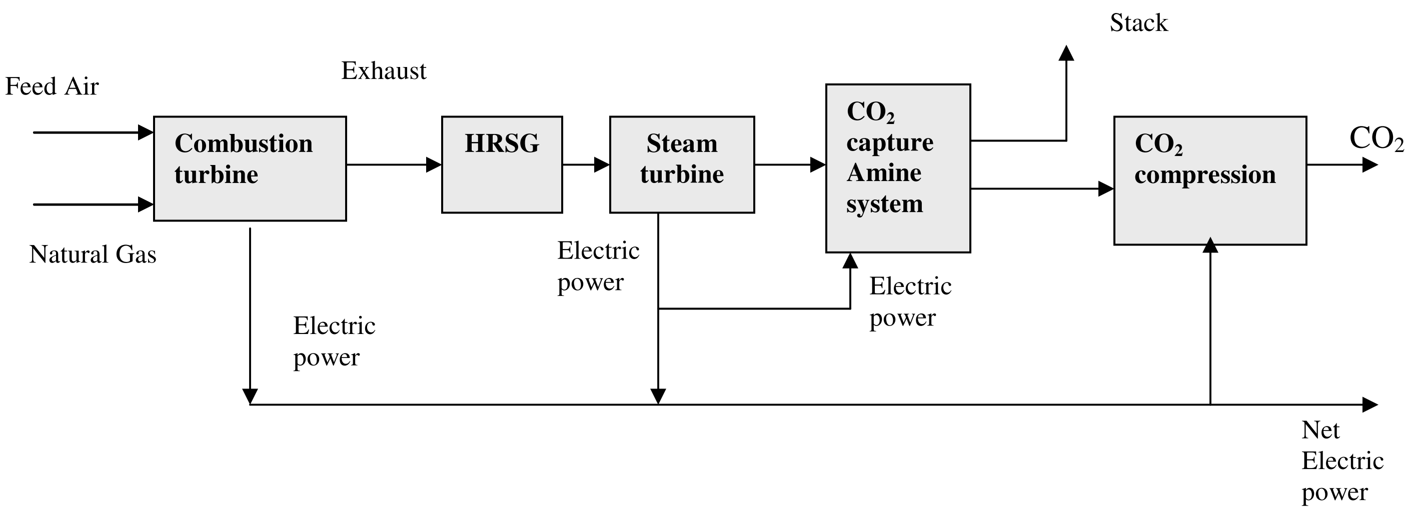

Figure 3.8: NGCC plant with CO_2 capture

All criteria and concepts explained above will be used in the next chapter which encompasses the engineering analysis and modeling of the power plants.

Chapter 4: Engineering analysis

This chapter comprises techno-economic modeling and assessment of the fossil fuel power plants: Pulverized Coal (PC) plant, coal-based Integrated Gasification Combined Cycle (IGCC) plant and Natural Gas Combined Cycle (NGCC) plant. Each plant has been modeled without and with CO_2 capture and storage. The modeling tool is Integrated Environmental Control Model with Carbon Sequestration (IECM-cs)[10] provided by Carnegie Mellon University (CMU). For each power plant concept a base plant with its corresponding unit operations has been defined. The configuration of the plant is influenced by the fuel characteristics (esp. in case of coal) and the multi-pollutant emission constraints, which they have to follow. The engineering modeling delivers mass flow rates (e.g. carbon emissions, multi-pollutant emissions), associated plant costs (capital, operating, and maintenance), and plant performance data (e.g. net plant output, efficiency), thus builds a framework to assess these technologies at a high level of technical and economical concern. The results of the modeling are used for energy-economic analysis in chapter 5.

4.1. Modeling the power plants

In general various technologies exist for electricity production. In the present thesis combustion based fossil fuel power plants are studied. The following power plant concepts are modeled and analyzed:

- Pulverized coal combustion without CCS (PC)
- Pulverized coal combustion with post combustion CCS (PCC)
- Pulverized coal combustion with oxyfuel CCS (PCO)
- Integrated Gasification Combined Cycle without CCS (IGCC)
- Integrated Gasification Combined Cycle with pre-combustion CCS (IGCCC)
- Natural Gas Combined Cycle without CCS (NGCC)
- Natural Gas Combined Cycle with post combustion CCS (NGCCC)

For each concept a base plant has been defined. The base plant makes the basis for modeling and argumentation in this thesis. The configuration of the base plant chooses, in particular, unit operations for the power plant, which depends on the fuel type as well as the emission regulations imposed on the plant. The quality of the fuel is especially important when it comes to coal based power plants. The design[11] and choice of unit operation for each base plant concept are explained in section 4.2.

As the configuration of the coal-based power plant may vary due to the characteristics of the coal fed to them, these plants have been modeled with different types of coals. The properties of the coal, such as heating value, carbon content, sulfur content, ash content, and moisture will affect the choice of unit operation and thus the design parameters of the plant. In general, coal is categorized in bituminous, sub-bituminous and lignite. Under this categorization, this thesis studies two bituminous coals (Appalachian medium sulfur

[10] To get more familiar with IECM modeling tool, please refer to [23].
[11] One should note that the design may differ among references due to the possibility of choosing alternative unit operations.

and Illinois # 6), one sub-bituminous coal (Wyoming Powder River Basin) and one lignite coal (North Dakota lignite). Table 4.1 shows the characteristics of these coals, which have been obtained from IECM database. The quality of German coals from Ruhr coalfield is similar to Appalachian medium sulfur and the German lignite from Rhineland is comparable with the North Dakota lignite; therefore the results obtained from these coals can be applied to them.

Coal	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
Type	Bituminous	Bituminous	Sub-bituminous	Lignite
Heating Value (kJ/kg)	30840	25350	19400	14000
Carbon (wt%)	73.81	61.2	48.18	35.04
Hydrogen (wt%)	4.880	4.2	3.310	2.68
Oxygen (wt%)	5.41	6.02	11.87	11.31
Chlorine (wt%)	0.06	0.17	0.01	0.09
Sulfur (wt%)	2.13	3.25	0.37	1.16
Nitrogen (wt%)	1.42	1.16	0.7	0.77
Ash (wt%)	7.24	11	5.32	15.92
Moisture (wt%)	5.05	13	30.24	33.03
Price ($/GJ)	1.5	1.23	0.94	0.68

Table 4.1: Coal characteristics [IECM database] and coal price

The modeled power plants should follow the regional air pollutant emission constraints, which are, besides the fuel type, other determinant factors in base plant configuration. The constraints are especially important when it comes to PC plants as they emit higher amount of pollutants compared to IGCC and NGCC. In this thesis the power plants have to meet European emission limit value (ELV) for Large Combustion Plant as emission constraint. A case study, which applied the current United States New Source Performance Standards (NSPS), resulted in no considerable different plant configuration and model output. The results of this case study are to find in sub-section 4.3.4.1, whereas the case study itself is elaborated in appendix A.

After configuring the plant and choosing the suitable unit operations, the design parameters for each unit operation and the overall plant are set. For modeling the power plants with their corresponding design parameters, IECM tool, which is developed for the U. S. Department of Energy's National Energy Technology Laboratory (NETL) by CMU, has been used. The required data for modeling i.e. economical and technical parameters and the assumptions for the configuration plants are the results of a wide literature review and expert opinions. For more information about specific topics the references [4], [20] and [21] can be advised.

4.2. Base plant configuration

This section involves the base plant configuration for each power plant concept stated in section 4.1. Moreover, this section can be regarded as the deterministic case where no uncertainty is applied to the power plants.

4.2.1. Pulverized Coal plant without CCS

Table 4.2 provides an overview of the unit operations and their typical design parameters for PC plants. The configuration of PC plants is influenced by coal type; therefore the unit operations and their actual parameters can vary among the coals.

Parameter	**Unit operation**
	Boiler
Type	Supercritical
Efficiency	82-89% dependent on the coal type
Gross electrical output	500 MW
	Control systems
	Low NO_X burners[12]
Maximum NO_X Removal Efficiency	50%
	Selective catalytic reduction (SCR) [13]
Maximum NO_X Removal Efficiency	90%
	Cold-Side electrostatic precipitator (ESP)
Particulate Removal Efficiency	~ 99%
Actual SO3 Removal Efficiency	25%
	Wet flue gas desulphurization (FGD)[14]
Reagent	Lime
Maximum SO2 Removal Efficiency	98%
Scrubber SO3 Removal Efficiency	50%
Particulate Removal Efficiency	50%
Power Requirement[15]	1.699%
	Mercury control[16]
Type	By injecting activated carbon
	Solid management
Type	Fly ash is disposed with FGD wastes

Table 4.2: PC unit operations and main design parameters

Boiler:
For the PC plant without CCS, supercritical boiler has been selected as unit type. The boiler has an efficiency[17] of 82-89% dependent on the coal type. Gross electrical output is set at 500 MW (as megawatts of internal power produced). This parameter will be studied later as uncertain parameter.

Control systems:
Control systems should be applied to the plant for controlling NO_X[18], particulate matter and SO_2.
- *Low NO_X burners:*
To date, reductions in power plant NO_X emissions have been achieved mainly through the use of low NO_X burners; therefore here low NO_X burners with 50% maximum NO_X removal efficiency have been applied to all plants. Due to a study of

[12]Not applied in the case of PC oxyfuel
[13]Not applied in the case of PC oxyfuel
[14] For the low sulfur coals such as PRB, FGD can be omitted in PC plants.
[15] All the power requirements stated here are relative to the gross electrical output
[16] Applied only in case of sub-bituminous and lignite coals
[17] Efficiency is defined as net electrical output to the energy content in the fuel
[18] The term NO_X refers to the composite of NO and NO_2. The other nitrogen oxides seldom occur in appreciable quantities and then only under special conditions.

Burns & McDonell [13], more than 90% of the 50 PC plants reviewed in this study use low NO_X burners for combustion control.

- *Selective catalytic reduction (SCR):*
In response to more stringent emission reduction requirements recently imposed on power plants, the use of selective catalytic reduction (SCR) has become more prevalent. In the modeling, therefore, SCR has been applied to all PC plants for post combustion NO_X control. Selective Catalytic Reduction (SCR) technology can achieve 90% NO_X removal. .
The use of an SCR system for NO_X control leads to additional multi-pollutant interactions. The injection of ammonia introduces a new constituent in the flue gas stream. Unreacted ammonia can adversely affect the saleability of collected flyash because of its odor and may be regarded locally as an undesired air pollutant. SCR and SNCR systems thus must be designed to achieve very low levels of ammonia slip, which may limit the level of NO_X reductions that are achievable. More subtle interactions stem from catalytic reactions within an SCR reactor. For example, SCR systems tend to oxidize some SO_2 thus increasing the level of sulfur trioxide (SO_3) in the flue gas stream. This increases the level of sulfuric acid aerosol emissions reportable under the Toxics Release Inventory. On the other hand, SO_3 is also a gas conditioning agent that can improve the performance of an electrostatic precipitator. Thus, power plants with SCR systems can experience improved ESP (electrostatic precipitator) performance, and new plants can (in principle) be designed with a slightly less expensive ESP. A plant with both SCR and wet FGD can achieve an even greater ESP cost reduction. The level of NO_X reduction depends on coal sulfur level [14]. Almost all PC plants reviewed in the study of Burns & McDonell [13], utilize SCR as the post-combustion NO_X control system.

- *Electrostatic precipitator (ESP):*
An electrostatic precipitator (ESP) or fabric filter can be used for particulate emission control. Although ESP has higher maintenance costs, it requires less energy and has high capture efficiency at the same time, and is standard on all PC units; therefore in the modeling ESP has been chosen for particulate removal. PC plants routinely achieve more than 99% particulate removal [4].

- *Wet flue gas desulphurization (FGD):*
In the modeling, SO_2 emissions have been controlled via wet flue gas desulphurization (FGD) due to its greatest share in market and being commercially a proven technology for SO_2 reduction. According to Burns & McDonell [13], almost half of the studied PC plants use wet FGD for SO_2 control whereas the other half use spray dry absorber, dry FGD or dry scrubber. FGD applied on the PC plants has SO_2 removal efficiency of 98%. However, coal sulfur level impacts the SO_X emissions level achievable. For the PC plants without CCS, the wet FGD option has been applied to all types of coals except for Wyoming Powder River Basin coal because of its very low sulfur content. Reducing SO_2 using an FGD system gives rise to more complex multi-pollutant interactions. Besides capturing SO_2, a wet FGD also removes

particulate matter with 50% efficiency and air toxics. Thus, an FGD system provides emission control benefits beyond SO_2 alone [14].

- *Mercury adsorption by activated carbon:*

Mercury in power plant flue gases can be captured in two ways. It can be adsorbed onto the surface of a sorbent material such as activated carbon, or it can be dissolved in an aqueous solution such as in a wet lime or limestone FGD system. For existing coal-fired plants with only a particulate collector such as an ESP, mercury control can be achieved by injecting activated carbon upstream of the ESP. To achieve high levels of mercury control, substantial amounts of carbon injection are required, increasing the load on the particulate collector. The additional use of water injection to cool the flue gas can significantly reduce the activated carbon requirement and the associated load on the particulate collection device. On the other hand the power plants already equipped with a wet FGD system can achieve mercury emission reductions at substantially lower costs [14]. The decision of which technology to use depends on the chemistry of the applied coal. Following the statement in sub-section 3.1.4.4, for bituminous coals under study, namely Appalachian medium sulfur and Illinois #6, the presence of an SCR system together with a wet FGD system can achieve high levels of mercury control, thus eliminating the need to inject activated carbon. For PRB and lignite coals, additional mercury removal is accomplished by activated carbon injection.

- *Fly ash disposal:*

Coal combustion waste which is mainly fly ash contains toxic contaminants and should be properly disposed. Therefore in the modeling, solid management has been considered in all the plants and fly ash is disposed with FGD wastes.

4.2.2. Pulverized Coal combustion with post combustion CCS

For the PC plants with post combustion CCS in this thesis, the CO_2 capture with amine system uses MEA as absorbent. Table 4.3 shows briefly the design parameters used in the amine system of the post combustion PC capture plants and also the CO_2 transport and storage data. Regarding the other unit operations, almost all the criteria used to model the PC plants without CCS, can be applied to the PC plants with CCS; just in the case of PRB coal, FGD should be added for SO_2 control which is due to the CO_2 capture with amine. The problem considered is that the SO_2 in the flue gas would reduce the absorptive capacity of MEA, as the absorbers prefer to react with SO_2 rather than with CO_2. The loss of the absorbent is an important extra effort for the operation of a chemical absorption based carbon capture plant, resulting in higher O&M costs [7]. Therefore pre-conditioning the flue gas with FGD is necessary for all coal types including PRB coal.

Parameter	Unit operation
	Amine system
	Absorber
Absorbent used	MEA
Absorbent cost	1425 $/tonne
Maximum CO2 Removal Efficiency	90%
Scrubber CO2 Removal Efficiency	90%
SO2 Removal Efficiency	99.5%
SO3 Removal Efficiency	99.5%
NO2 Removal Efficiency	25%
HCl Removal Efficiency	95%
Temperature Exiting direct contact cooler	50°C
Number of Operating Absorbers	2
Amine Scrubber Power Requirement	21.64 - 24.42 %[19]
Nominal absorbent Loss	1.5 kg MEA/ tonne CO2
	Regenerator
Regeneration Heat Requirement	4000 kJ/kg CO2
Steam Heat Content	2001 kJ/kg steam
Pump Efficiency	75%
	CO2 transport and storage
CO2 Product Stream pressure	13.79 MPa
CO2 Compressor Efficiency	80%
CO2 Unit Compression Energy	117.9 kWh/tonne CO2
Pipeline length	100 km
CO2 Storage Method	Geological
Min Outlet Pressure at storage site	10.30 Mpa

Table 4.3: PC post combustion CCS parameters

Amine system:
-Absorber:
The amine system with MEA can achieve up to 90% CO_2 removal. An amine scrubber is used at the end of the flue gas train. Since the absorbents are highly reactive, which could lead to damage of the equipment, they are solved in water [7]. A direct contact cooler (DCC) is desirable to cool down the flue gases to about 45- 50 °C, in order to improve absorption of CO_2 into the amine absorbent, to minimize absorbent losses, and to avoid excessive loss of moisture with the exhaust gases. The temperature of the flue gas affects the absorption reaction because absorption of CO_2 in MEA absorbent is an exothermic process favored by lower temperatures [15]. Furthermore, MEA is a reactive absorbent and it will be lost due to unwanted reactions. In general, the nominal loss of MEA is estimated as about 1.5 kg MEA/ tonne CO_2. In order to reduce the problem regarding SO_2, additives are added to the absorber.

- *Regenerator:*
Another important factor in capture plants is the regeneration of the amine. The amount of heat required for the regeneration of the MEA absorbent (loaded with CO_2)

[19] The power requirement of the amine scrubber depends on the coal type with the least amount for Appalachian medium sulfur and the most for the Lignite.

in the stripper/ regenerator section is expressed as the amount of heat (in kJ) per unit mass (kg) of CO_2 captured. Theoretically, the heat of reaction that needs to be supplied in order to reverse the absorption reaction between CO_2 and MEA is about 1900 kJ/ kg CO_2. The actual amount of heat required for regeneration of the absorbent is much higher, about 2-3 times higher than this theoretical minimum. This is because of the large amount of latent heat taken up by the dilution water in the absorbent. A wide range of numbers has been reported for the regeneration heat requirement of MEA system. The majority of the sources report a heat requirement of about 4000 kJ/kg CO_2 [15]. In addition, the absorbent cost is one of the main variable cost components. Considering MEA cost of 1425 $/tonne, the absorbent loss will cause high expenses which amounts to almost 2 $ per tonne CO_2.

CO_2 transport and storage:
After capturing, CO_2 product stream is compressed to a pressure of 13.79 MPa and then transported via 100 km pipeline to the storage site. CO_2 will be then stored in a geological reservoir. Minimum outlet pressure at storage site is 10.30 MPa.

4.2.3. Pulverized Coal combustion with oxyfuel CCS

Another concept to capture CO_2 from PC power plants is oxyfuel combustion, which uses pure oxygen for combustion, instead of air. This approach results in a concentrated CO_2 stream for disposal, which consequently leads to reductions in equipment sizes and heat losses, and to savings in the cost of flue gas treatment (See part 3.1.2.2).

Oxyfuel technology is now being promoted as a promising option for CO_2 capture from power plants. However, it is still in the early stages of development. Although various parts of this system (such as oxygen production and flue gas treatment) are commercially available today, only laboratory-scale studies of oxyfuel combustion for coal-fired power generation have been conducted so far, with some pilot plant studies also in progress[20]. Lack of available large-scale oxyfuel plant and practical data, makes the configuration of oxyfuel plant regarding the choice of unit operations more complicated. This thesis relies on the theoretical studies carried out in the field of oxyfuel combustion in order to determine the suitable unit operations for oxyfuel plant concept. Reference [16] has listed different oxyfuel configurations assumed by different studies which are presented in table 4.4.

[20] Recently, Vattenfall has announced a plan to build a 40MWth demonstration plant using oxyfuel combustion technology.

Study/ Reference	Year	Plant type and Size (MWg)	Flue gas recycle	Particle Removal	FGD	SCR	Flue gas cooler	Dry CO_2 refining
Dillion	2004	New, 740	Dry	ESP	no	no	yes	distill
AAL	2004	New, 533	wet	ESP, out	yes	no	no	No
AAL	2003	Retrofit, multiple	wet	ESP, out	yes	optional	no	No
AAL	2003	New, multiple	no	ESP	yes	no	no	No
ANL	2003	Retrofit	wet	ESP	yes	no	no	No
U Waterloo	2003	Retrofit, 400	wet				yes	distill
Chalmers/ Vattenfall	2002	New, 933	wet	cyclone	no		no	distill
ALSTOM/ ABB/AEP	2001	Retrofit, 463	wet	ESP	yes	no	Yes	distill
AP/BP/ Babock	2000	New	wet		no	no	yes	distill
Simbeck	2000	New, 575	dry	Baghouse	no	no	no	No
Simbeck	2000	Retrofit, 318	wet	ESP	no	no	no	No
McDonald & Palkes	1999	Retrofit, 318	wet	ESP	no	no	yes	distill
Babock	1995	600	dry	ESP	no	no	yes	distill
Air Products	1992	Retrofit, 572	wet					distill
Japanese	1992	New, 1000	Wet, dry	ESP	no	no	yes	No

Table 4.4: Different oxyfuel configurations by different studies [16]

Taking into account table 4.4, there are some inconsistencies among these studies e.g. flue gas treatment for SO_2 and NO_X control. Especially important for this thesis is the question whether to use FGD for SO_2 control or not as due to Croiset and Thambimuthu the conversion of coal sulfur to SO_2 is decreased from 91% for the air case to about 64% during oxy-fuel combustion. The reason for the decrease in SO_2 during oxy-fuel combustion, they believe, is due to SO_3 formation and subsequent sulfur retention [17].

This is important because on the one hand using FGD complies with anti-pollutant regulations and avoids boiler corrosion problems which are caused due to CO_2 recycle and acid formation; on the other hand the SO_2 control system can increase the cost of the plant. Therefore, a case study has been undertaken which compares oxyfuel plants with and without FGD. Figure 4.1 shows the corresponding results for SO_2 emissions in both cases, whereas figure 4.2 outlines the capital required.

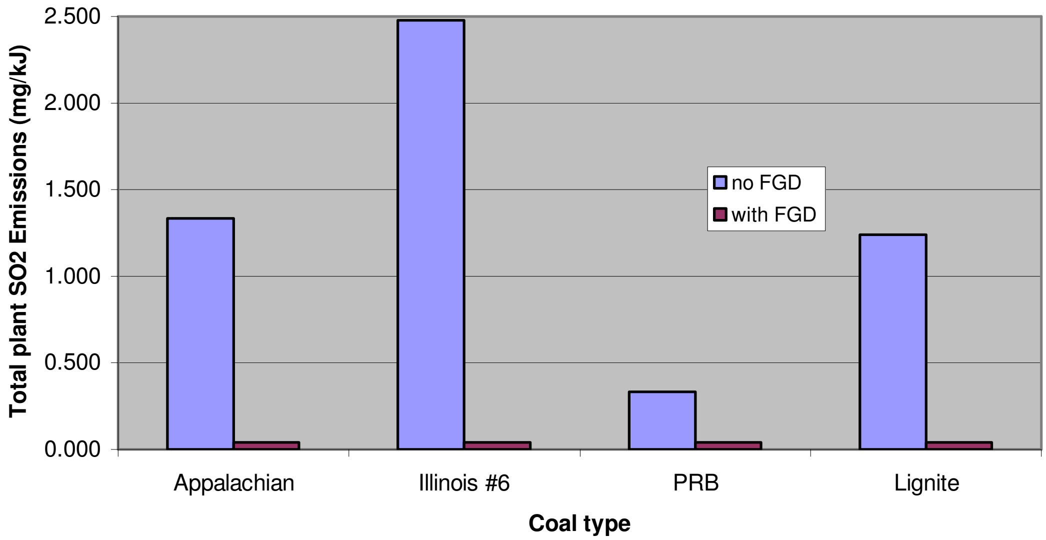

Figure 4.1: Comparison of total SO_2 emissions for oxyfuel plants with and without FGD (all coals)

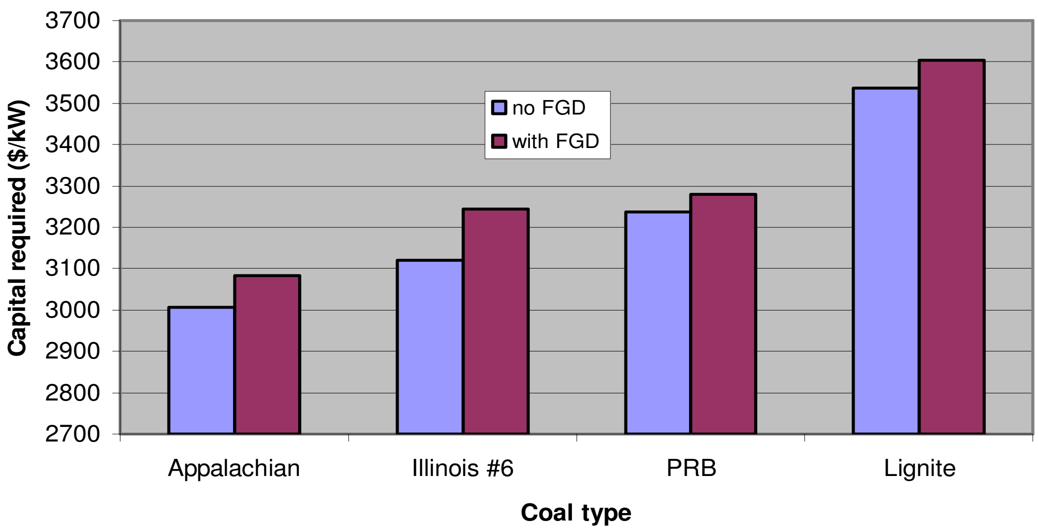

Figure 4.2: Comparison of total capital required for oxyfuel plants with and without FGD (all coals)

As obvious from figure 4.1, SO_2 emissions are reduced significantly when SO_2 control system is used. These emissions are not identical for different types of coal as the sulfur content of the coals varies. Addition of SO_2 control system increases the total capital required due to additional unit operation and material costs, but the high reduction in SO_2 emissions outweighs the investment increase. Adding the SO_2 control system is even more emphasized when the power plants are obliged to follow specific regulations regarding their SO_2 emissions and taxes should be paid when the actual emission exceeds the set emission constraint. In this thesis, therefore, FGD has been chosen for the oxyfuel configuration. Technology improvement (e.g. upgraded metallurgy in the boiler) may omit the need of FGD for oxyfuel in the future. For instance Air Products PLC, which has recently finalized a study for Vattenfall about the purification and compression of the flue gases from oxyfuel combustion, has

realized that almost all traces of SO_2 and NO_X can be removed as weak acids when the pressure is increased, which might make conventional sulfur-removal equipment unnecessary [18].
The other unit operations applied are identical to the PC plant (with/ without post combustion). The only difference in oxyfuel configuration is the elimination of NO_X control unit operation, as various experimental studies indicate significant reduction in NO_X formation when using O_2/CO_2 recycle.
Oxyfuel combustion system with flue gas recycle is also commonly referred to as "O_2/CO_2 combustion system". Table 4.5 summarizes the main design parameters of the oxyfuel CO_2 capture via O_2/CO_2 recycle:

Parameter	Unit operation
	O_2/CO_2 recycle
CO2 Capture Efficiency	95%
Flue gas recycle ratio (FGRR)	70%
Particulate Removal Efficiency	50%
Recycled Gas Temperature	37.78 °C
	ASU
Type	Cryogenic
Power requirement	231.9 kWh/tonne O_2
Oxygen purity	95%

Table 4.5: PC Oxyfuel CO_2 capture parameters

O_2/CO_2 recycle:
The oxyfuel combustion has the potential to capture higher amounts of CO_2, therefore a CO_2 capture efficiency of 95% has been assumed for oxyfuel plants in the modeling. There are some additional requirements in the plant design due to the nature of the oxyfuel combustion. One major additional design parameter is flue gas recycle ratio. The flue gas is recycled to maintain the design temperature and required heat fluxes in the boiler. The flue gas recycle ratio (FGRR) is the fraction of total flue gas generated that is recycled back into the boiler. Higher FGRR implies a lower oxygen mole fraction in the O_2/CO_2 oxidant entering the boiler, whereas zero FGRR is the case of pure oxygen combustion with no flue gas recycles. Studies using flue gas recycle assume FGRR values in the range 0.6-0.85 [16]. In the model a nominal value of 0.7 has been applied.

Air separation unit (ASU):
The oxyfuel plant nominally utilizes a conventional cryogenic air separation unit. As stated in sub-section 3.1.2.2, ASU uses a large amount of energy which leads to reduction in efficiency. In the model, the unit ASU power requirement is assumed to be 231.9 kWh/tonne O_2 which corresponds to approximately 14% of the gross power output depending on the coal type. The oxygen purity is also important. Many studies have reported that 95% is an optimal level of oxygen purity which is used in the modeling as well.

The parameters of CO_2 transport and storage are identical to the ones used in post combustion PC plant (table 4.3). For more information about the design of the oxyfuel plant please refer to reference [16].

4.2.4. Integrated Gasification Combined Cycle without CCS

The major unit operations and design parameters[21] used in the configuration of IGCC plants are briefly presented in table 4.6 and described afterwards. The configuration plant is identical for all types of coal.

Parameter	Unit operation
	GE (Texaco) gasifier[22]
Feed type	Slurry
Gasifier type	oxygen blown, entrained flow
Pressure	4.2 MPa (42 bar)
Temperature	1343 °C (2450 °F)
	ASU
Type	cryogenic
Power requirement	231.9 kWh/tonne O_2
	Syngas cooling unit
Type	quench process with injecting water
	Syngas clean-up:
	Raw gas cleanup
Particulate removal	100%
	Sulfur removal:
	Hydrolyzer
COS to H_2S Conversion Efficiency	98.50%
	Sulfur Removal Unit (Selexol)
H_2S Removal Efficiency	98%
COS Removal Efficiency	33%
CO_2 Removal Efficiency	15%
Power Requirement	0.6409 %
	Claus Plant
Sulfur Recovery Efficiency	95%
Power Requirement	0.07077%
	Tail gas Treatment
Sulfur Recovery Efficiency	99%
Power Requirement	0.2153 %
	Power block:
	Turbine
Gas Turbine Model	GE 7FA
Turbine inlet temperature	1327°C
No. of Gas Turbines	2
	Air Compressor
Pressure Ratio (outlet/inlet)	15.70
Adiabatic Compressor Efficiency	70%
	Combustor
Combustor Inlet Pressure	2.027 MPa
Combustor Pressure Drop	0.02758 MPa
	Heat Recovery Steam Generator
HRSG Outlet Temperature	121 °C
	Slag management
Type	In landfills

Table 4.6: IGCC unit operations and main design parameters

[21] The design parameters below are for Appalachian medium sulfur, these can slightly vary for other coals.

[22] E-Gas (Oxygen blown), KRW (Air blown) and Shell (Oxygen blown) are other alternatives which are not investigated in the thesis.

Gasifier:
GE (Texaco) gasifier is an oxygen-blown, entrained flow gasifier for which coal is prepared in a slurry form. The coal flow rate[23] and the amount of water needed depend on the coal type. As the sulfur and ash content of the coal increase and the heating value decreases, higher coal flow rate is required. For lignite, for instance, the coal flow rate is almost four times the one of Appalachian medium sulfur. The composition of the slurry may influence the gasifier efficiency and the efficiency of a whole IGCC power plant. Due to the study of [Breton, 2002], in order to ensure the slurryability, the total water percentages in the slurry for Appalachian medium sulfur, Illinois #6, PRB and ND Lignite should be no less than 34%, 37%, 44% and 50%, respectively. Pressure range for a Texaco gasifier is from 15 bars to 70 bars. Increasing the gasification pressure reduces the size of the equipment but increases the operating costs; therefore here a medium pressure of 4.2 MPa (42 bar) has been used. The gasifier temperature is set at 1343 °C (2450 °F).

Air separation unit (ASU):
GE (Texaco) gasifier is oxygen-blown, for which oxygen is supplied by an air separation unit. Currently, air separation in large scale is achieved by using a cryogenic process in which air is cooled to a liquid state and then subjected to distillation. However, an ASU based on the cryogenic process requires a large amount of power (231.9 kWh/tonne O_2) and accounts for the largest parasitic load on an oxygen-blown IGCC plants. In addition, cryogenic processes in general have large capital cost. For these reasons, lowering the cost of air separation will significantly improve the economics and efficiency of IGCC power plants and lower their capital costs [5].

Syngas cooling unit:
The syngas is cooled using quench process by injecting water.

Syngas cleanup options:
- Raw gas cleanup:
The cool syngas should be cleaned before entering the turbine. Raw gas cleanup area can achieve 100% particulate removal.

- Sulfur removal:
The key factor in achieving the environmental performance of IGCC systems is sulfur removal from the syngas. Sulfur is contained in two types of acid gases, H_2S and COS.

- Hydrolyzer:
The first step in the sour gases removal process is to remove the carbonyl sulfide (COS) from the gas stream. For an IGCC system without CO_2 capture, the conventional method is to pass the syngas through a fixed bed, catalytic hydrolysis reactor, which will hydrolyze the COS to CO_2, H_2S and CO. The hydrolyzer converts COS to H_2S with an efficiency of 98.5%.

[23] The coal flow rate for Appalachian medium sulfur is 169 tonne/hr.

- *Acid gas removal:*

H_2S is then captured by an acid gas removal system which is used with the GE gasifier in the model. The H_2S removal efficiency of the sulfur removal unit is 98%. The Selexol/Claus/SCOT process is used for sulfur removal and recovery. The elemental sulfur recovered from these processes is a saleable byproduct.

Combined cycle power block:

The power block consists of gas turbine/generator, air compressor, combustor, heat recovery steam generator (HRSG) and the steam turbine. The cleaned gas, which is a mixture of H_2, CO and CH_4, is saturated and reheated before it is fed into gas turbine combustion chamber. The IGCC system in the base configuration uses two GE 7FA gas turbines. In the uncertainty study, carried out in sub-section 4.5.2, the effect of different number of turbines is examined. The hot exhaust from gas turbine is used to generate steam for a steam cycle through the HRSG.

Slag management:

The coal ash is primarily converted to a fused slag and is less leachable compared to fly ash, and can be more easily disposed. The slag is managed into landfills (Please refer to sub-section 3.2.6.5 for more information).

As the particulate emissions from IGCC power plants are low, there is no need for extra particulate emission control.

4.2.5. Integrated Gasification Combined Cycle with pre-combustion CCS

For the IGCC capture plant, sour water gas shift reaction plus Selexol process are introduced to the plant. Table 4.7 illustrates the main design parameters[24] of the unit operations used for CO_2 capture in IGCC plants.

Parameter	Unit operation
	Water-Gas Shift Reactor
CO to CO2 Conversion Efficiency	95%
COS to H2S Conversion Efficiency	98.5%
Catalyst type	Sour shift catalysts based on Co-Mo
	Selexol CO2 capture
CO2 Removal Efficiency	90%
H2S Removal Efficiency	94%
Number of Operating Absorbers	2
Power Requirement	7.446 %

Table 4.7: IGCC CO_2 capture parameters

Water-Gas Shift Reactor:

In this design, after sulfur removal, a water gas shift reactor is added to convert CO into CO_2 with 95% efficiency. The remaining H_2 is then fed to the gas turbine to produce power. Two types of catalyst are usually used for the water gas shift reaction:

- Sour shift catalysts based on Co-Mo
- Clean shift catalysts based on Fe-Cr or Cu

[24] The design parameters below are for Appalachian medium sulfur, these can slightly vary for different coals

For IGCC systems with GE (Texaco) quench design, preliminary thermodynamic analysis shows that sour shift dominates the clean shift option because syngas at particle scrubber outlet has all the characteristics required by the sour shift reaction (temperature and steam to carbon ratio) [5]. The water gas shift reactor, moreover, omits the need of a separate COS hydrolysis system, as it has a conversion efficiency of COS to H_2S up to 98.5%.

Selexol CO_2 capture:
The resulting CO_2 is then captured in a Selexol process which is a physical process with a removal efficiency of 90%. Selexol process is a commercial glycol-based process for acid gas removal which has a relatively low energy requirement. In the capture plant, the acid gases (H_2S and CO_2) are removed through two Selexol processes, separately. Depending on the coal type, the number of absorbers in the Selexol capture unit may differ and thus the power requirement. As an example, for low rank coals such as lignite, 4 absorbers with power requirement of about 8% of the gross electric output, are in operation, which subsequently bring about efficiency reduction.
The CO_2 transport and storage data are as stated in table 4.3.

4.2.6. Natural Gas Combined Cycle without CCS

The NGCC configuration plant of is simple relative to the other technologies since it doesn't need any extra control systems for multi pollutants. This is due to the fact that natural gas is a cleaner fuel compared with coal. Furthermore, gas-fired plants are not so sensitive to the fuel type as coal-fired plants. The power block data which include parameters for gas turbine/generator, air compressor, combustor, heat recovery steam generator (HRSG) and the steam turbine are the only parameters to set in the model. The assumptions and the values for the power block components in NGCC are similar to the ones in IGCC (table 4.6). Natural gas with a flow rate of 67.5 tonne/hr enters two GE 7FA gas turbines. The off-gas of the gas turbine then enters the HRSG and after that in a steam turbine. The efficiency of NGCC depends on the temperature and pressure of the gas entering the gas turbine. In the current power cycle, a turbine inlet temperature of 1327°C has been considered. The turbine inlet temperature is studied further on as uncertain parameter (sub-section 4.5.3).

4.2.7. Natural Gas Combined Cycle with post combustion CCS

For the NGCC plant that features CCS, CO_2 capture technology is an amine system post-combustion one which accomplishes the capture via adding the MEA scrubber to the system. The CCS design parameters for the NGCC capture plant are identical to the ones for PC post-combustion plant which are elaborated in table 4.3. The amine regeneration heat requirement in this power plant is set at 5422 kJ/kg CO_2 as the lower concentration of CO_2 leads to higher energy requirement.

4.3. Results of the base plant configuration

Model assumptions

In the modeling of the power plant concepts, besides the design parameters, other assumptions are required. Some major model assumptions are summarized in table 4.8. It is worth mentioning here that some of the parameters are studied later as uncertain parameter e.g. capacity factor.

Parameter	Assumption
Plant Capacity factor	75%
Fixed Charge Factor (FCF)[25]	0.148
Discount rate before taxes	0.1
Plant book life	30 years
Air pollutant constraints	European ELV for LCP
Currency	Constant dollar 2005

Table 4.8: Model main assumptions

Results and conclusions:
The model delivers many results, including performance data (e.g. efficiency, emissions) and economic results. Among these results, the parameters which are useful for further modeling in *REMIND* have been chosen. These parameters are net plant efficiency, total plant CO_2 emissions, total captured CO_2, fixed O&M, variable O&M and capital required. In addition, the data about the multi pollutant emissions and the revenue required are also listed here to enable better implications.

4.3.1. Plant performance

- Net Plant Efficiency, HHV (%)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC	39.34	38.60	38.27	36.25
PCC	29.72	28.90	27.66	26.15
PCO	31.22	30.31	29.25	27.79
IGCC	37.19	34.49	32.40	23.70
IGCCC	32.04	29.36	27.13	18.89
	Natural Gas			
NGCC	50.15			
NGCCC	42.80			

Table 4.9: IECM Model Net Plant efficiency, HHV (%)

As obvious from table 4.9, the coal power plants have significantly lower efficiency than NGCC in both cases with and without CCS. With the usage of high rank coals such as Appalachian medium sulfur or Illinois #6, coal power plants can be a technology of choice for electricity production. The table also draws the conclusion that PC plants without capture have slightly better efficiency than IGCC without capture for bituminous coals, and much better efficiency for low rank coals. With addition of post-combustion capture to PC plants, 10% reduction in efficiency relative to non-capture PC plants is observable, whereas for oxyfuel this reduction amounts to

[25] This parameter, also known as the capital recovery factor, is used to find the uniform annual amount needed to repay a loan or investment with interest [IECM Help].

8%. IGCC capture plants, however, show the lowest reduction in efficiency (5%) when the capture is applied, relative to PC capture plants. For NGCC capture plant, the efficiency decrease due to capture is about 8%. Figure 4.3 shows the efficiency of these power plants in which the coal power plants use Appalachian medium sulfur

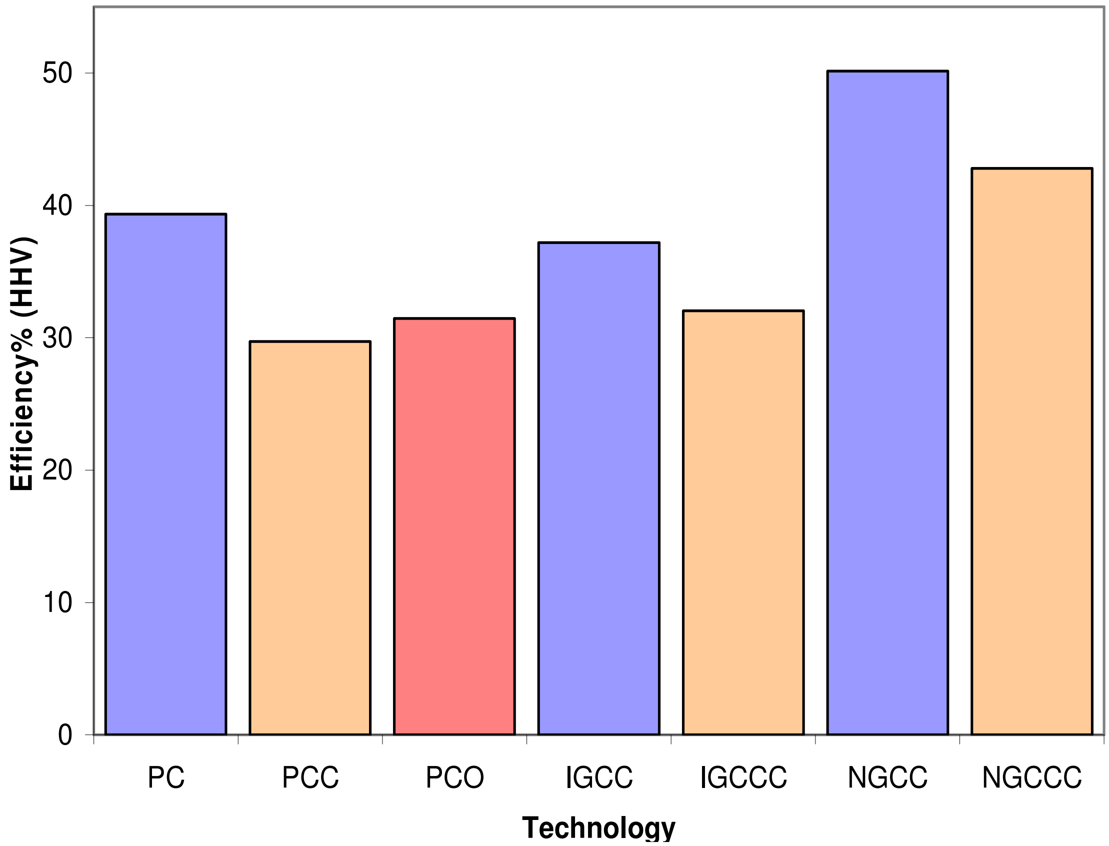

Figure 4.3: Plant efficiency (coal type: Appalachian medium sulfur)

In order to see how sensitive the coal power plants are to the coal type, figure 4.4 illustrates the efficiency of PC, PC post-combustion capture plant, PC oxy-fuel, IGCC and IGCC capture plant relative to the coal type used in them. As obvious from the graph, the coal quality influences the performance of IGCC plants more significantly than PC plants. The decline in IGCC efficiency is more spectacular when using low-rank coals, which is due to the large oxygen requirement. PC plants can still be suitable options for electricity production from low-rank coals such as lignite because despite the reduction in the efficiency, they still have acceptable performance. For all coal types, PCO shows a better performance than PCC.

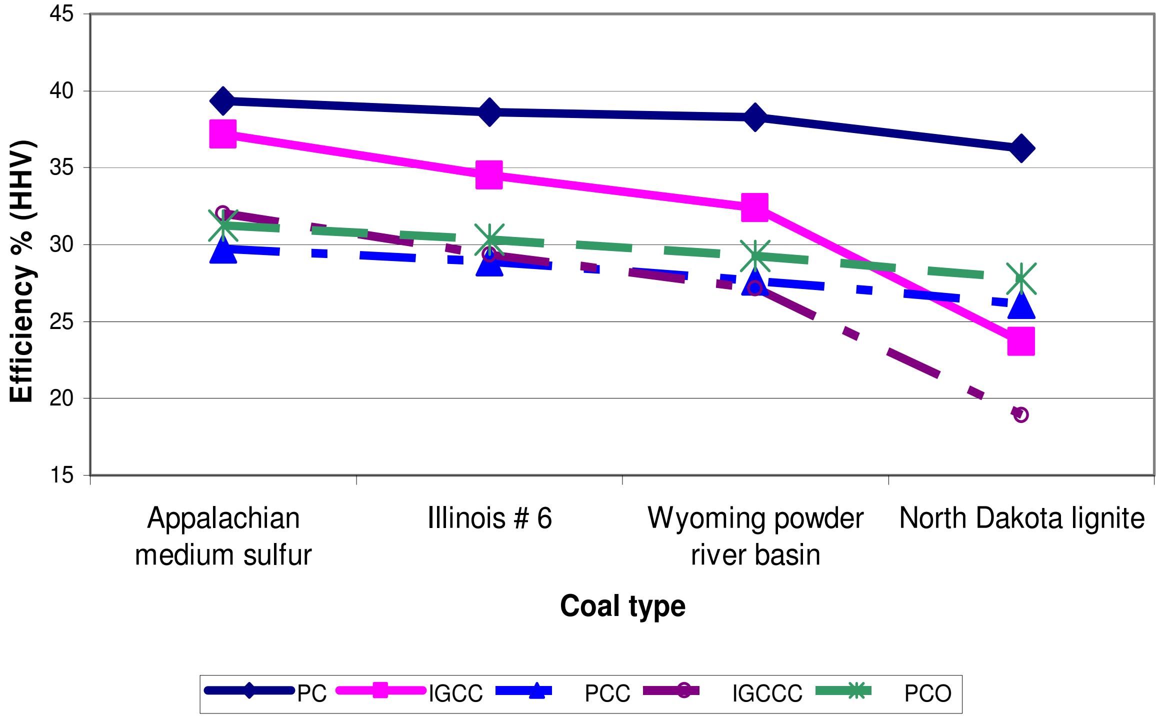

Figure 4.4.: Effect of coal type on the efficiency of coal power plants

It should be noted here that the efficiencies obtained from IECM are based on the higher heating value. Expressing the efficiencies in lower heating value (LHV) has been avoided here because the LHV based efficiencies can be somewhat misleading as they exclude the energy required to vaporize the water [10]. Converting HHV efficiencies in LHV, the corresponding efficiencies will be 2 to 4 percentage higher, depending on the coal type, than the ones listed in table 4.9. But still the efficiencies are relatively lower than the ones found in some literatures. Lower efficiencies resulted from IECM modeling can be due to several reasons, mainly the design parameters. For PC plants, these differences can be attributed to the higher levels of SO_X and NO_X removal used in IECM.
In addition, IGCC plants are assumed to apply GE/quench gasifier, which has the lowest efficiency compared to Shell gasifiers or GE (Texaco) Heat Exchanger gasifiers. On the other hand, it offers the cheapest price. Despite the poor performance of high ash coals in Texaco gasifier, these coals show more suitable performance in dry feed gasifier such as Shell gasifier. On the whole it should be mentioned that gasification of low rank coals, including sub-bituminous and lignite, for electric generation purposes is under question.
The model also uses F turbine, which has a lower efficiency comparing G or H turbines. F turbines are the most commonly used turbines with syngas. G turbines have not yet been tested for syngas application.
Another factor which increases the efficiency of the IGCC plants is the integration of ASU (air separation unit) with gas turbine (figure 3.6). Part or all of the ASU air may be supplied from the gas turbine compressor outlet to reduce or eliminate the need for

a less efficient ASU compressor [4]. This will lower the total unit cost and increase efficiency and power output.
Higher IGCC efficiencies in some studies are due to the assumption of using high temperature gas in sulfur removal unit, which is nowadays proven to be not possible. It should also be noted these efficiencies are mostly the results of modeling and not from real plants. The MIT study [4] reports the efficiency of real plants, which complies fairly well with the model results of IECM: Polk IGCC with a Texaco-GE water-slurry gasifier, radiant and convective syngas cooling but no combustion turbine-air separation unit integration operates at 35.4% (HHV) generating efficiency. The Wabash River IGCC with a water-slurry fed E-Gas gasifier, radiant and convective syngas cooling and no integration operates at about 40% generating efficiency. The IGCC in Puertollano Spain with a dry-feed Shell type gasifier, radiant and convective and combustion turbine-air separation unit integration has a generating efficiency of about 40.5% (HHV). Supercritical PC units operate in the 38 to 40% efficiency range, and ultra-supercritical PC units in Europe and Japan are achieving 42 to 46% (HHV) generating efficiency.

- Net Electrical Output (MW)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC	459	456.5	467.0	456.8
PCC	346.7	341.7	337.6	329.6
PCO	347.9	342.7	340.5	333.6
IGCC	537.6	541.5	552.4	612.4
IGCCC	492.2	478.6	465.8	469.2
	Natural Gas			
NGCC	506.5			
NGCCC	432.3			

Table 4.10: IECM Model Net Electrical Output (MW)

The gross electrical output is set at 500 MW for PC plants. This value will be one of the uncertain parameters studied further on. The net electricity output will be calculated by subtracting a sum accounting for boiler use, hot-side SCR use, cold-side ESP use, wet FGD use and amine scrubber use (for the capture plant) from the gross electrical output.
For IGCC plants, the gross electrical output is dependant on the number of turbines used. This value corresponds to the total generator output minus the energy requirement of the air compressor and turbine shaft losses. The energy usage of the air compressor accounts for one third the energy produced from the generator. To get the net electricity output, other energy requirements of the different parts of the plant such as miscellaneous power block usage, air separation unit use, gasifier use, sulfur capture use and Selexol CO_2 capture use (for the capture plant) should be considered. Among the above components, the ASU is the cause of the most energy losses. It should be notified here that the coal flow rate to the IGCC power plant is increased in the case of low rank coals, which leads to more power generation compared to high rank coals. The decline in the net power output of the low rank coals in case of IGCC

capture can be explained by increased auxiliary power usage, which is, as stated above, related to ASU, CO_2 Selexol capture and the compressor.
Another interesting point is that the reduction in the electricity production in case of capture relative to the case without capture is much higher for PC capture plants compared to IGCC capture plants. The main reason is that the chemical absorption in case of PCC is much more energy consuming than physical absorption in case of IGCCC.
For NGCC, the gross electricity produced is calculated in the same way as for the IGCC plants. The net electricity is then resulted from subtracting the energy losses due to miscellaneous power block use and CO_2 absorption use (in case of capture plant) from the gross electrical output.

4.3.2. CO_2 emissions and captured CO_2

- Power plant total CO_2 out

	Appalachian medium sulfur		Illinois # 6		Wyoming powder river basin		North Dakota lignite	
	tonne/MWhr	tonne/hr	tonne/MWhr	tonne/hr	tonne/MWhr	tonne/hr	tonne/MWhr	tonne/hr
PC	0.81024	371.9	0.840526	383.7	0.857173	400.3	0.918345	419.5
PCC	0.107326	37.21	0.112087	38.3	0.118839	40.12	0.127367	41.98
PCO	0.050647	17.62	0.052933	18.14	0.055653	18.95	0.059353	19.80
IGCC	0.823475	442.7	0.895476	484.9	0.980992	541.9	1.350914	827.3
IGCCC	0.089638	44.12	0.088863	42.53	0.089395	41.64	0.108845	51.07
	Natural Gas							
	tonne/MWhr				tonne/hr			
NGCC	0.367423				186.1			
NGCCC	0.043049				18.61			

Table 4.11: IECM Model Power plant total CO_2 out

CO_2 emissions of the power plants are expressed once as tonne CO_2/MWhr based on MW output of each plant and once as emission rate in tonne/hr. The emission rates are attractive for comparing CO_2 emissions of each power generation technology relative to its capture plant. When comparing the power plant concepts in terms of CO_2 emissions, the unit tonne/hr can be to some extent misleading, because the net output of the power plants are different. Therefore, it is advisable to use CO_2 emissions in tonne/MWhr. Figure 4.5 facilitates comparing CO_2 emissions of the power plants. It can be concluded that NGCC capture plant has the lowest emission per unit output. IGCC capture plants show lower emissions (per output) than PC post combustion plants. However, the lowest emissions from coal power plants are observed by applying oxyfuel as it has the highest carbon efficiency.

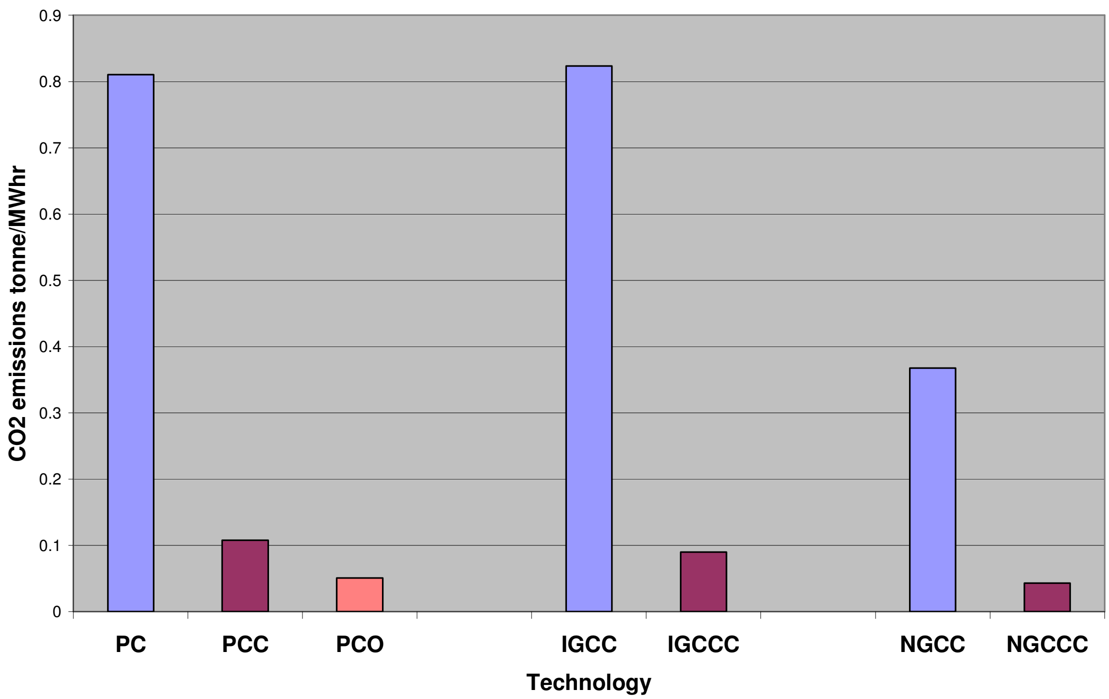

Figure 4.5: Power plants CO_2 emissions with and without CCS (Coal type: Appalachian medium sulfur)

The table can also be beneficial for analyzing the emission of each coal type when used in different coal power plants. It is worth mentioning that these emissions will be further on converted to emission coefficients as kg carbon equivalent per GJ input in *REMIND* modeling.

- ***Captured CO_2 to Storage***

	Appalachian medium sulfur		Illinois # 6		Wyoming powder river basin		North Dakota lignite	
	tonne/MWhr[26]	tonne/hr	tonne/MWhr	tonne/hr	tonne/MWhr	tonne/hr	tonne/MWhr	tonne/hr
PCC	1.034617	335.1	0.988715	345.6	0.935439	360.9	0.871958	378
PCO	1.019637	341.2	0.975242	351.4	0.927793	367	0.869656	383.6
IGCCC	1.154586	426.3	1.037728	461.2	0.924023	504.1	0.630137	744.6
	Natural Gas							
	tonne/MWhr				tonne/hr			
NGCCC	2.580896				167.5			

Table 4.12: IECM Model Captured CO_2 to Storage

The table above expresses the captured CO_2 for the plants with CCS. NGCCC shows the highest capability in capturing CO_2. Among the coal capture plants, IGCCC shows a better potential in capturing CO_2 for bituminous coals relative to PC capture plants, but this conclusion will be reversed for low rank coals such as lignite.

[26] Based on net electrical output of the capture plant.

4.3.3. Costs

The major cost carrying components of the PC plants are: Combustion NO_X control (LNB), post-combustion NO_X control (SCR), mercury control (when applied), PM control, SO_2 control, and CO_2 capture (for capture plants).

The main cost components of the IGCC plants are: Air separation unit, gasifier area, particulate control, sulfur control, CO_2 capture (for capture plant) and the power block.

The main cost component for NGCC plants is the power block. In the case of capture plant, extra costs are resulted from post-combustion CO_2 capture.

- Fixed O&M (M$/yr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC	22.87	23.69	18.31	24.92
PCC	28.35	29.26	29.11	30.83
PCO	35.56	36.49	36.47	38.70
IGCC	30.27	33.77	35.56	53.43
IGCCC	38.50	44.18	46.34	69.83
	Natural Gas			
NGCC	7.087			
NGCCC	11.08			

Table 4.13: IECM Model Fixed O&M (M$/yr)

Fixed cost components are: Operating labor, maintenance labor, maintenance material and overhead costs associated with administrative and support labor.

- Variable O&M (M$/yr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC	43.10	46.96	44.81	51.60
PCC	77.87	88.13	76.35	89.99
PCO	57.03	60.10	57.77	65.16
IGCC	43.51	46.76	52.53	84.63
IGCCC	69.60	73.28	79.27	117.7
	Natural Gas			
NGCC	107.8			
NGCCC	124.8			

Table 4.14: IECM Model Variable O&M (M$/yr)

The variable operating costs include costs for consumables, fuels, slag and ash disposal, and byproduct credits. It should be noted here that the variable O&M cost calculated in IECM encompasses fuel costs. In *REMIND*, on the other hand, the fuel costs are not considered in variable O&M costs. It can be concluded that NGCC non-capture and capture plant have the highest variable O&M costs which is due to considering the high gas price in the O&M costs. PC and IGCC non-capture plants with bituminous coals have almost the same variable O&M costs. However, these costs increase significantly for low rank coals in IGCC plants leading to almost 65% higher O&M costs for IGCC with lignite relative to PC with the same coal. When capture is applied to coal power plants, oxyfuel carries the lowest O&M costs. For bituminous coals, IGCC capture plants rank the second and PC post combustion plants the third, bearing in mind that this conclusion will be reversed for low rank coals.

- Capital required ($/kW-net)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC	1500	1569	1441	1688
PCC	2539	2675	2737	2977
PCO	3057	3205	3252	3572
IGCC	1665	1890	1971	2837
IGCCC	2280	2712	2959	4626
	Natural Gas			
NGCC	665.2			
NGCCC	1085			

Table 4.15: IECM Model Capital required ($/kW-net)

According to ref. [19], the total capital requirement (TCR) includes the total plant investment, prepaid royalties, spare parts inventory, preproduction (or startup) costs, inventory capital, initial chemicals and catalyst charges, and land costs.
Due to the results, the gas fired plants have the lowest capital required without and with CCS compared to coal fired plants. In addition, one can conclude from the table that the investment costs of coal power plants are highly influenced by the coal type. This is especially spectacular for IGCC plants (figure 4.6); by switching the coal from Appalachian medium sulfur to North Dakota lignite, investment costs will rise up to 70%, which is mainly due to the fact that GE (Texaco) gasifiers are not suitable for gasification of low-rank coals. The other notable point is that adding CCS to IGCC plants results in 37% increase in the investment costs for Appalachian medium sulfur whereas for PCC the increase in the investment costs due to integration of CCS amounts to 69% with the same coal and for PCO almost double the investment costs of PC is required. This makes IGCC plants more attractive when CCS is applied and high rank coals are used for power generation. However, this conclusion is hardly applicable to low rank coals.

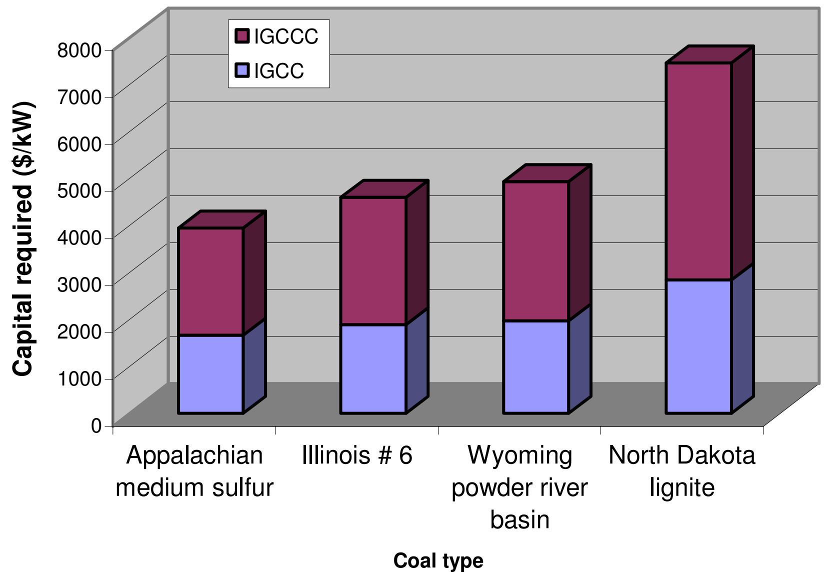

Figure 4.6: Total Capital required for IGCC plants without and with capture using different coals

- *CO_2 Transport annualized capital cost ($/ton CO_2 transported)*

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PCC	2.377	2.304	2.207	2.107
PCO	2.46	2.393	2.291	2.193
IGCCC	2.029	1.876	1.716	1.262
	Natural Gas			
NGCCC	4.382			

Table 4.16: IECM Model CO_2 Transport annualized capital cost ($/ton CO_2 transported)

The values above are calculated for 100 km pipeline. Total capital required for CO_2 transport amounts to 39 M$ for all PC post-combustion plants and PC oxyfuel plants regardless of the coal type. For IGCC plants with pre-combustion, this cost is 42.36 M$ for all coal types except for lignite with 46.03 M$. Regarding the data available in IECM, this is due to higher CO_2 transport process area costs. For NGCC plant with post-combustion, this cost reads 35.93 M$

- *Revenue Required ($/MWh)*

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC	55.62	58.85	53.00	63.48
PCC	103.8	112.5	109.1	122.8
PCO	110.2	116.7	116.6	129.3
IGCC	58.35	65.16	68.62	98.14
IGCCC	84.73	98.38	107.6	164.9
	Natural Gas			
NGCC	49.48			
NGCCC	72.23			

Table 4.17: IECM Model Revenue Required ($/MWh)

According to ref. [19], the calculated cost of electricity, also known as total annualized cost, is the levelized annual revenue requirement to cover all of the capital and operating costs for the economic life of the plant. The cost of electricity (COE) obtained from IECM is of special interest for comparison with electricity production cost obtained from *REMIND* later on. It is worth mentioning here that NGCC among the non-capture options and NGCCC among the capture options offer the cheapest COE. PC plants result in slightly cheaper COE for high rank bituminous coals relative to IGCC plants, but the price gap increases as the heating value of the coal decreases. However, IGCCC proves to be capable of producing the cheapest electricity among the coal capture plants (apart from lignite). Comparing the PC capture plants, it is to notice that COE of PCO is higher than PCC which can be attributed to higher investment costs.

- CO_2 avoidance costs (\$/tonne CO_2)

	Appalachian medium sulfur	**Illinois # 6**	**Wyoming powder river basin**	**North Dakota lignite**
PCC	68.543291	73.65063	75.98181	74.99572
PCO	71.854277	73.45163	79.34924	76.62465
IGCCC	35.94807	41.1846	43.71928	53.749
	Natural Gas			
NGCCC	70.13494			

Table 4.18: CO_2 avoidance costs (\$/tonne CO_2)

Cost of CO_2 avoided is calculated as below:

$$\text{Cost of CO}_2\text{ Avoided} = \frac{COE_{\text{capture}} - COE_{non-capture}}{CO_2emissions_{non-capture} - CO_2emissions_{capture}}$$

For calculating this cost, COE as \$/MWh and CO_2 emissions as tonne/MWh have been used. As obvious from table 4.18, cost of CO_2 avoidance is the least for IGCC. The reason is that the increase in the cost of electricity with addition of capture is relatively lower while the reduction in CO_2 emissions is relatively high.

4.3.4. Multi pollutant emissions

The emission of PM, SO_2 and NO_X is of special interest of the present thesis as it enables comparing the environmental performance of the power plants. As stated in the modeling assumptions, European emission limit value (ELV) for Large Combustion Plant (LCP) has been used as emission constraint (see table 4.23). These constraints are equivalent to 400 mg/Nm^3 SO_2, 200 mg/Nm^3 NO_X and 50 mg/Nm^3 PM [20].

- Power plant total particulate emission to the air

	Appalachian medium sulfur		Illinois # 6		Wyoming powder river basin		North Dakota lignite	
	tonne/hr	mg/kJ	tonne/hr	mg/kJ	tonne/hr	mg/kJ	tonne/hr	mg/kJ
PC	0.07222	0.0172	0.0732	0.0172	0.07555	0.0172	0.07801	0.0172
PCC	0.03611	0.0086	0.0366	0.0086	0.03778	0.0086	0.03901	0.0086
PCO	0.01027	0.0026	0.0104	0.00258	0.01073	0.00258	0.01105	0.00258
IGCC	0.002237	0.0004	0.002429	0.0004	0.002639	0.0004	0.003999	0.0004
IGCCC	0.002377	0.0004	0.002523	0.0004	0.002657	0.0004	0.003846	0.0004
	Natural Gas							
NGCC	0							
NGCCC	0							

Table 4.19: IECM Model Power plant total particulate emission to the air

The general conclusion that merges from comparing the particulate emission of the above plants is that NGCC plants have zero particulate emissions and therefore the least pollutant power plant concept. Among the coal power plants, IGCC plants (with and without CCS) have negligible PM emissions. PC oxyfuel plant show lower emissions compared to PC plant without capture and with post-combustion capture. The next conclusion is the lower the coal quality, the higher the PM emissions. On the whole these emissions comply with the PM emission constraint applied to the power plants.

- Power plant total SO_2 out

	Appalachian medium sulfur		Illinois # 6		Wyoming powder river basin		North Dakota lignite	
	kg-mole/hr	mg/kJ[27]	kg-mole/hr	mg/kJ	kg-mole/hr	mg/kJ	kg-mole/hr	mg/kJ
PC	9.113	0.1424	9.235	0.1453	22.73	0.3328	9.852	0.1417
PCC	0.0087	0.00015	0.01637	0.00027	0.002273	0.00004	0.008736	0.00014
PCO	2.596	0.0425	2.627	0.043	2.720	0.042	2.802	0.042
IGCC	2.360	0.029	4.772	0.054	0.7652	0.008	5.003	0.034
IGCCC	0.2840	0.0033	0.5393	0.0059	0.07883	0.00082	0.4604	0.0033
	Natural Gas							
NGCC	0							
NGCCC	0							

Table 4.20: IECM Model Power plant total SO_2 out

As obvious from table 4.20, PC plants without capture emit the highest amount of SO_2 in comparison with other power plant concepts. Adding post combustion capture to PC plants will reduce these emissions to a considerable amount. This is highly associated with the nature of amine-based CO_2 control. Due to ref. [14], amine-based absorbents absorb all acid gases (and not just CO_2), therefore the level of SO_2 in the flue gas must be kept very low, typically 10 ppm or less to prevent absorbent usage

[27] The value presented here as mg/kJ refers to equivalent SO_2 emissions.

by SO_2. This means that the most economical approach to CO_2 capture will be to reduce SO_2 emissions to levels substantially below those currently required for regulatory compliance. IGCC offers a route to achieving modest SO_2 reductions as the use of advanced coal-based generation technology such as IGCC will comply more severe sulfur removal even when the CO_2 capture is not considered. By converting to gas as fuel to the power plant, SO_2 emissions associated with power generation would be eliminated.

- Power plant total NO out (kg-mole/hr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC	4.488	4.608	4.867	4.899
PCC	4.488	4.608	4.867	4.899
PCO	6.663	8.205	11.07	8.423
IGCC	0.9711	0.9766	0.9766	1.003
IGCCC	0.9979	1.001	0.9993	1.028
	Natural Gas			
NGCC	0.9675			
NGCCC	0.9675			

Table 4.21: IECM Model Power plant total NO out (kg-mole/hr)

- Power plant total NO_2 out

	Appalachian medium sulfur		Illinois # 6		Wyoming powder river basin		North Dakota lignite	
	kg-mole/hr	mg/kJ[28]	kg-mole/hr	mg/kJ	kg-mole/hr	mg/kJ	kg-mole/hr	mg/kJ
PC	0.2362	0.0517	0.2426	0.0524	0.2562	0.0537	0.2579	0.0523
PCC	0.1771	0.0511	0.182	0.0518	0.1921	0.053	0.1935	0.0517
PCO	0.3507	0.081	0.4318	0.0986	0.5824	0.1289	0.4433	0.0952
IGCC	0.05112	0.009	0.05139	0.0084	0.05139	0.0077	0.0528	0.0052
IGCCC	0.05253	0.0087	0.05266	0.0082	0.05257	0.0078	0.05411	0.0056
	Natural Gas							
NGCC	0.05094				0.013			
NGCCC	0.0382				0.013			

Table 4.22: IECM Model Power plant total NO_2 out

As seen before, the use of natural gas would simultaneously eliminate emissions of SO_2, particulates and solid wastes, and reduce the NO_X emissions substantially. Thus, from an environmental point of view, using natural gas for power generation has ancillary multi-pollutant benefits. Regarding the coal power plants, IGCC is favored over PC in both cases of capture and non-capture as its NO_X is much lower than the PC.

4.3.4.1. Multi- pollutant constraint comparison

The emission regulation imposed on the power plants can affect the plant configuration in a sense of choosing the unit operations and setting their design

[28] The value presented here as mg/kJ refers to equivalent NO_2 emissions.

parameters which may consequently alter the modeling results. In order to compare the influence of the multi-pollutant emission constraints, a case study has been carried out which models PC plants without CCS and with post-combustion CCS with the current United States New Source Performance Standards (NSPS)[29]. It should be noted that some countries set their own national emission limit values for LCPs. The whole case study can be found in appendix A. Here only the results are summarized.

Table 4.23 shows the corresponding values of the EU emission limit value for large combustion plants and the NSPS multi-pollutant emission constraints:

	Constraint as mg/KJ		**Constraint as lb/MBTU**	
Pollutant	**EU**	**NSPS**	**EU[30]**	**NSPS**
SO_2	0.1397	0.258	0.325	0.6
NO_X	0.06879	0.06449	0.16	0.15
PM	0.0172	0.0129	0.04	0.03

Table 4.23: EU. vs. NSPS Multi-pollutant emission constraint

By applying these two constraints, some model results either won't change or change negligibly, these are: Net plant efficiency, net electrical output, total plant CO_2 emissions for the cases with CCS[31] and captured CO_2. The revenue required is almost the same in both cases. The observed changes are:

- *SO_2 emissions* are much lower when EU constraints are applied to PC without CCS (exception PRB coal). The reason is the more stringent EU SO_2 constraint. SO_2 emissions in the case with CCS shows no or a very slight change, which can be neglected.
- *Particulate emissions* will be higher in case of applying EU constraints (both with and without CCS). The reason is most probably lower EU particulate emission constraint.
- *NO_X emissions* are the same for both constraints in both cases (with and without CCS) with an exception for lignite with lower emissions in case of EU constraints
- The *capital required* is slightly lower in case of applying EU constraints (exceptions are PC using Illinois #6 and lignite without CCS)

4.4. Uncertainty study

This section of the thesis focuses on the uncertainty associated with CCS technologies. Uncertainties can be applied to different aspects, such as plant performance, technical parameters, financing data, plant size, price of fuel, etc. Defining an uncertain parameter in the model may result in distribution function of some other parameters such as investment cost, O&M cost, efficiency, net electric output, emissions, COE, etc. Variability, on the other hand, is emphasized when applying different types of coal which

[29] These standards are applicable to all units constructed since 1978.
[30] EU constraints for large combustion power plants from reference [20].
[31] In the cases without CCS, just PRB shows no changes, but for the rest of the coals, CO_2 emissions will be slightly higher with EU constraints

has been discussed in sub-sections 3.1.3 and 3.2.5 and further elaborated in model results in section 4.3. In IECM uncertainty analysis is assessed via Monte Carlo simulation.

4.4.1. Monte Carlo Analysis (MCA)

The MCA is a method of varying a large number of parameters stochastically and to analyze the results by applying standard statistical methods [7]. In Monte Carlo simulation, a sufficient number of cases are run; each case with parameter values independently and randomly selected from distributions that characterize the uncertainty of the exogenous parameter. From the results of the simulation, a cumulative distribution function is generated that shows the probability of an outcome given the uncertainty in the inputs [5]. To run an uncertainty analysis, a probability distribution needs to be defined. Several types of probability distributions are normal distribution, lognormal distribution, uniform distribution, triangular distribution, Fractiles and Wedge Distribution[32]. The probability distribution selected for the uncertain parameters in this thesis is either uniform or triangular. Uniform probability is useful when a finite range of possible values can be specified, but it is not possible to specify which values in the range are more likely to occur than others. In Triangular distributions, in addition to the range, the most likely value (mode) can be specified [5].

4.4.2. Uncertain parameters

The choice of the uncertain parameters emerges from reviewing the literature. For each of these parameters a distribution range has been identified and their effect on cost and technical performance has been examined. The evaluation principle is the extent to which the selected parameter causes an impact on the criteria factors, namely plant efficiency, net power output, CO_2 emissions, O&M costs, capital required and COE (which is the most important criterion for a power plant). Preliminary study shows that the uncertainties associated with capacity factor, turbine inlet temperature, size of the plant and the fuel costs, have a significant influence on one or some of the criteria factors. Among these parameters the effect of the fuel price is not studied due to its minor relevance with this thesis. The literature also noted several other parameters subject to uncertainty for which no sensitivity study has been conducted here. These parameters are either factors related to financing the plant (e.g. interest rate) which is beyond the scope of this thesis or too specific technical parameters such as mole weight of Selexol, for which the uncertainty is mostly in conjunction with ongoing development. These parameters have smaller effect comparing the selected ones.

The results of uncertainty analysis are distribution functions which are shown as graphs demonstrating the criteria factor under question vs. its cumulative probability. The model also delivers four district digits of the uncertainty study which are: Mean, 2.5 percentile, Median (50the percentile) and 97.5 percentile. Below, the uncertainty analysis for capacity factor, plant size and turbine inlet temperature is described.

[32] Describing all distribution types is outside the scope of this thesis; please refer to ref. [21].

4.5. Results of uncertainty analysis

4.5.1. Capacity factor

As capacity factor of 75% has been reported as typical value for PC and IGCC plants by many references, a mean value can be specified for these plants, therefore a triangular distribution has been applied to capacity factor of PC and IGCC, with and without CCS. The capacity can change between 52.5% and 90% with 75% as most likely value. The capacity factor of NGCC plants is exposed to a uniform distribution ranging from 52.5% as minimum to 86.25% as maximum. In order to consider the large impact of natural gas price on the capacity factor, and thus to enforce compliance with the recent volatility of gas prices, no mean value for the capacity factor of NGCC plants has been specified.

Applying uncertainty to capacity factor will, above all, change the variable O&M costs for all these power plants regardless of fuel type. This fact is taken as granted, as the more the plant is in operation, the higher O&M costs it has to carry. Figure 4.7 demonstrates the immense effect of altering the plant working hours on variable O&M costs of PC capture plants with an example of Appalachian medium sulfur coal.

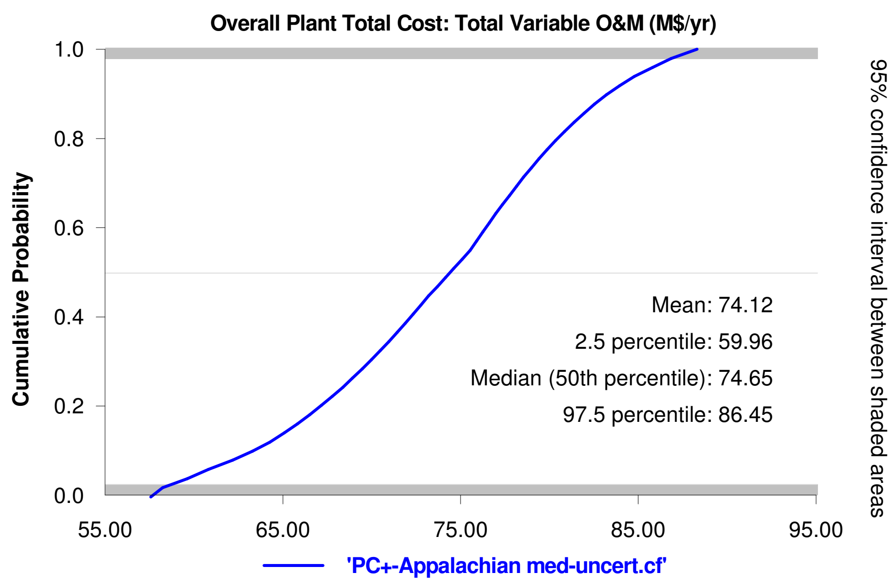

Figure 4.7: Cumulative probability of variable O&M costs for PCC using Appalachian medium sulfur coal with uncertain capacity factor

According to this figure, the probability that the variable O&M costs of the plant are less than 75 M$/yr is 50%, whereas the likelihood that these costs are lower than 65 M$/yr is only 10%. Although varying capacity factor leads to changes in variable O&M costs regardless of fuel type, coal type can influence the magnitude of the changes. Figure 4.8 illustrates the cumulative probability of variable O&M costs for all coal types in IGCC plants. As made clear from the graph, the effect of uncertain capacity factor is more impressive for low rank coals such as lignite.

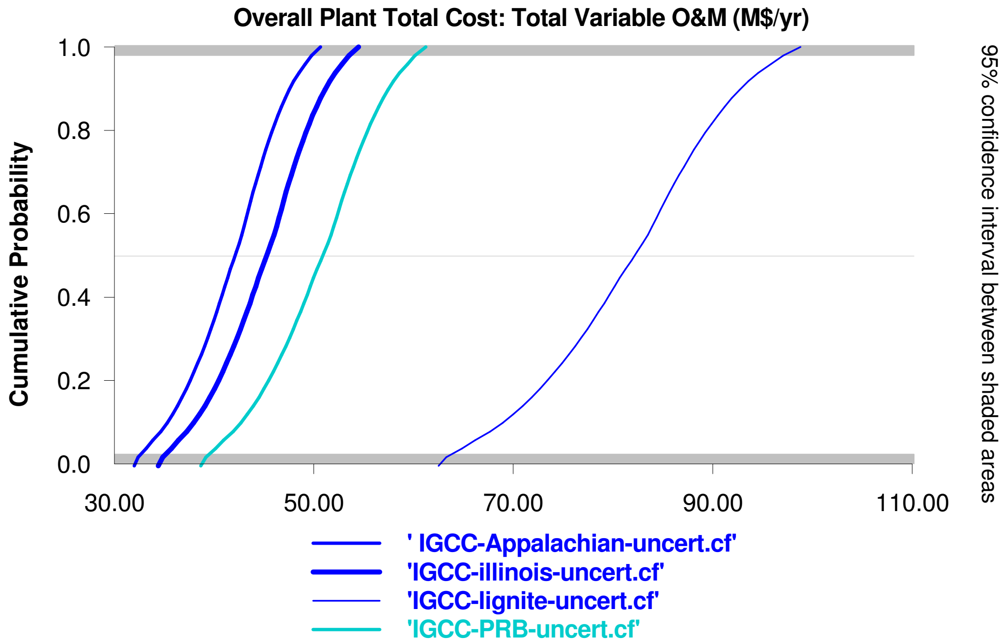

Figure 4.8: Cumulative probability of variable O&M costs for IGCC plant all coal types with uncertain capacity factor

As a result of alternating capacity factor, the cost of electricity changes respectively. Figure 4.9 and 4.10 show examples of cumulative probability of COE for IGCC plant and NGCC capture plant. Although O&M costs increase with growing capacity factor, the reduction in investment costs per MWhr prevails over the O&M costs increase. The highest COE is a result of lowest capacity factor and vice versa.

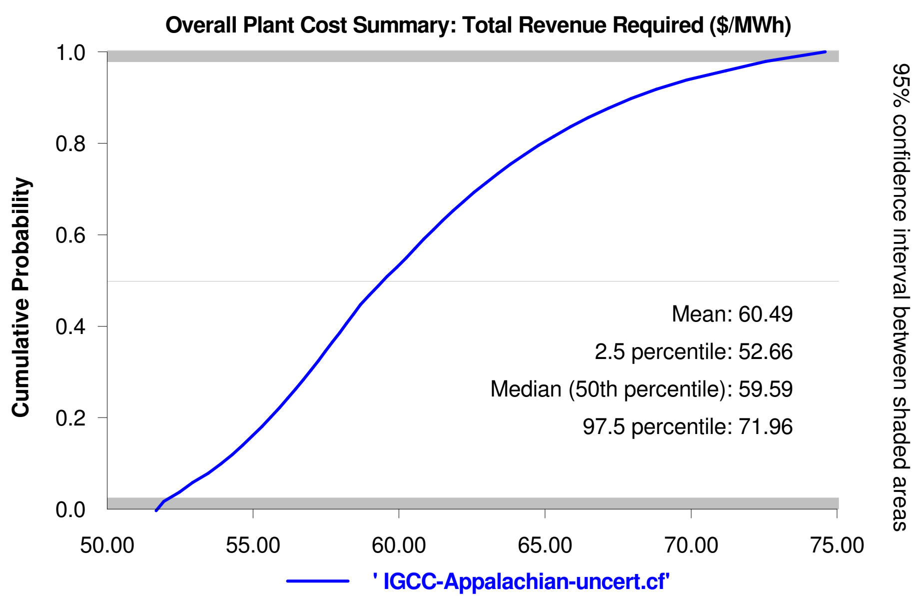

Figure 4.9: Cumulative probability of COE for IGCC plant using Appalachian medium sulfur coal with uncertain capacity factor

As obvious from figure 4.9, for IGCC with Appalachian medium sulfur almost 20 $/MWh difference is observable between 2.5 percentile and 97.5 percentile.

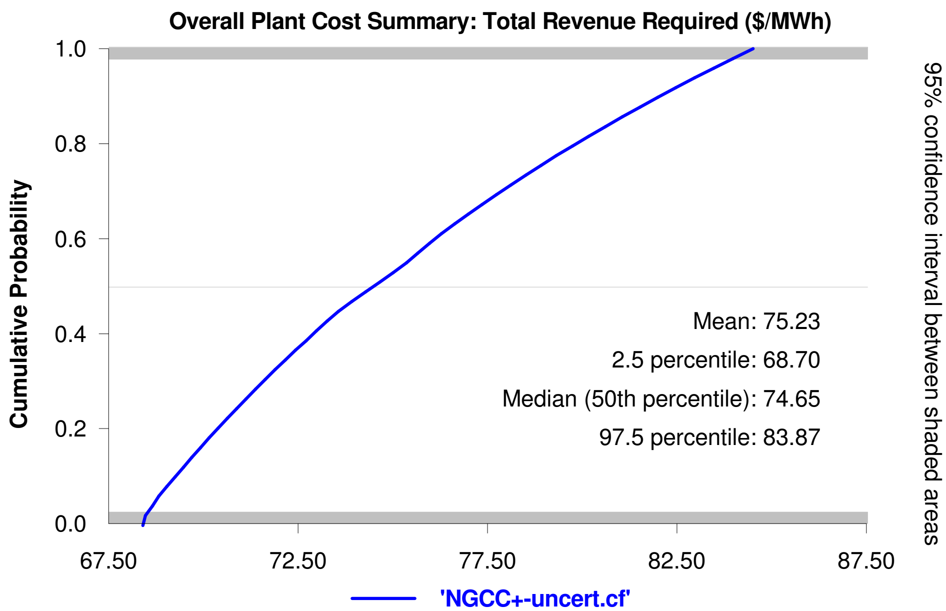

Figure 4.10: Cumulative probability of COE for NGCC capture plant with uncertain capacity factor

The other parameters either won't change or change negligibly. The investment costs will show a slight change in case of NGCC plants. Figure 4.11 illustrates the cumulative probability of capital required for NGCC plant without capture. As obvious from the graph, the changes amount to 1% and thus are not considerable.

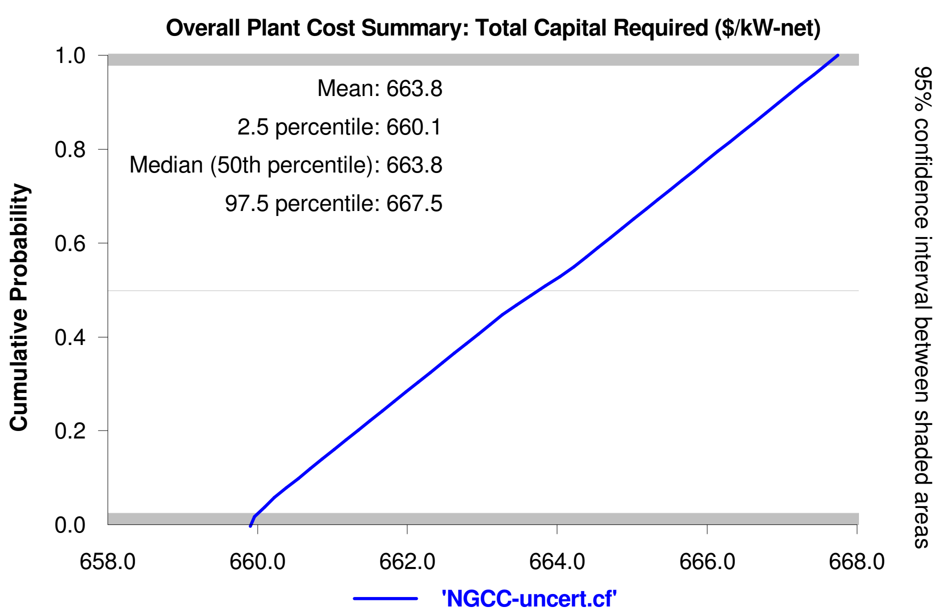

Figure 4.11: Cumulative probability of Capital required for NGCC plant with uncertain capacity factor

4.5.2. Plant size

In order to determine the role of plant size in performance and cost of PC plants, an uncertainty has been applied to the gross electrical output. The applied triangular distribution tends to change the gross plant output from 250 to 1000 MW with a mode of 500 MW (the value used for base plants). This uncertainty application has been carried out for all types of coal in PC without CCS, PC with post-combustion capture and PC oxyfuel. Employing uncertainty to plant size will have several interactions with other parameters including net plant output, O&M costs, investment costs, emissions and revenue required. Figure 4.12 outlines CO_2 emissions of PC plant with Appalachian medium sulfur coal subject to uncertain plant output.

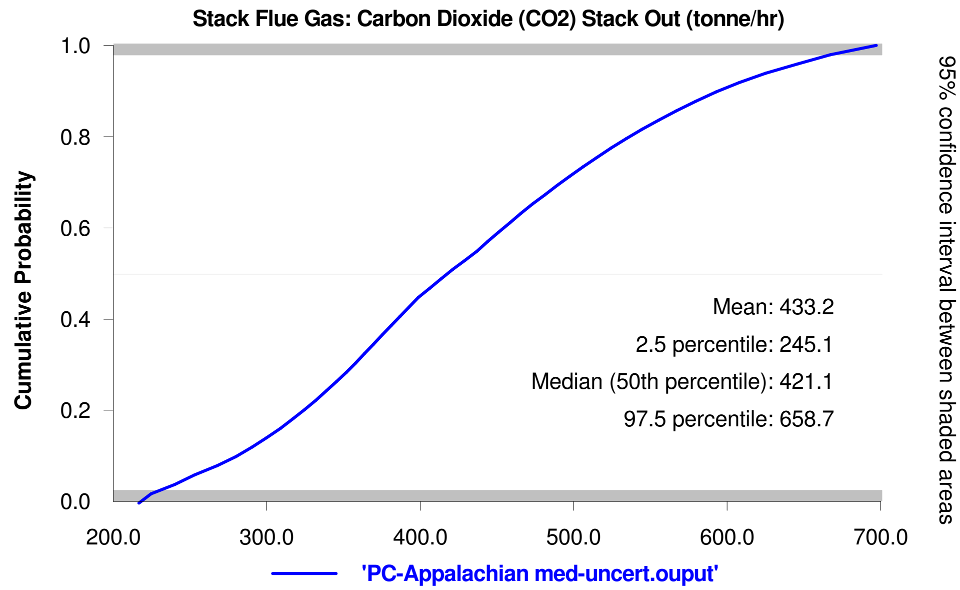

Figure 4.12: Cumulative probability of CO_2 emissions of PC plant with uncertain power output (Appalachian medium sulfur coal)

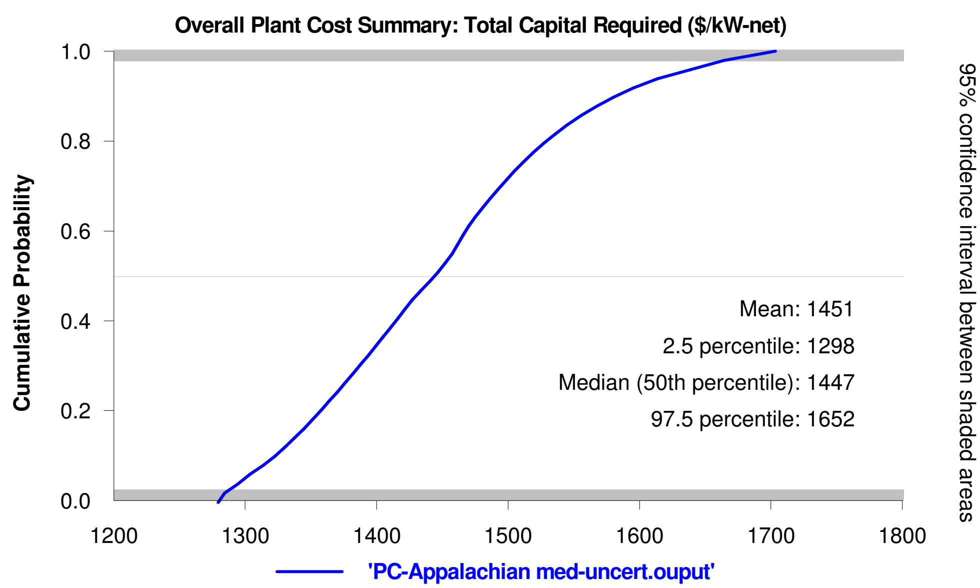

Figure 4.13: Cumulative probability of Capital required of PC plant with uncertain power output (Appalachian medium sulfur coal)

Figure 4.13 sketches out the investment costs for the same case to give a rough idea about the pronounced influence of the scale on PC plants. As obvious from this graph, the cost decrease per unit output due to plant size increase is considerable whereas the CO_2 emissions per unit output remains almost constant.

To evaluate the effect of plant size on the combined cycle power plants (i.e. IGCC and NGCC plants), the number of turbines has been varied relative to base plants, resulting in different power output consequently. Each plant concept, with and without CCS, has been modeled once with a single turbine and once with three turbines, in addition to the base plant case which utilizes two turbines.
The results of varying the number of turbines are given in table 4.24 for IGCC and IGCC capture plant with Appalachian medium sulfur as reference coal, NGCC and NGCC capture plant.

	Net Electrical Output (MW)	**Net Plant Efficiency, HHV (%)**	**CO2 emissions (tonne/hr)**	**Fixed O&M (M$/yr)**	**Variable O&M (M$/yr)**	**Capital required ($/kW.net)**	**COE ($/MWh)**
IGCC-1 turbine	267.4	37.00	221.4	21.66	21.75	1847	66.27
IGCC-2 turbines	537.6	37.19	442.7	30.27	43.51	1665	58.35
IGCC-3 turbines	808.0	37.26	664.1	39.00	65.26	1614	55.96
IGCCC-1 turbine	244.6	31.85	22.06	25.94	37.13	2458	94.55
IGCCC-2 turbines	492.2	32.04	44.12	38.50	69.60	2280	84.73
IGCCC-3 turbines	740.0	32.12	66.18	51.94	101.7	2245	82.11
NGCC-1 turbine	253.3	50.15	102.6	4.620	53.91	668.9	50.21
NGCC-2 turbines	506.5	50.15	205.1	7.087	107.8	665.2	49.48
NGCC-3 turbines	759.8	50.15	307.7	9.548	161.7	663.3	49.22
NGCCC-1 turbine	216.1	42.80	10.26	7.451	64.80	1174	77.27
NGCCC-2 turbines	432.3	42.80	20.51	11.08	124.8	1085	72.23
NGCCC-3 turbines	648.4	42.80	30.77	15.47	184.4	1103	71.71

Table 4.24: Effect of scale in parameters of IGCC, IGCCC, NGCC and NGCCC
(Coal: Appalachian medium sulfur)

The observed phenomenon is the determinant effect of scale on the economics of the plant. This effect is more dominant for IGCC plants than for NGCC plants. Changing the number of turbines, despite keeping the power plant efficiency almost constant, will, remarkably, alter the capital required. This fact is to realize in figure 4.14 which shows the investment costs of IGCC capture plant with different number of turbines using Appalachian medium sulfur coal. Interestingly, the drop in investment costs due to using more turbines prevails over the increase in O&M costs and thus results in cheaper electricity. Comparing IGCC with one turbine and three turbines for instance, the cost of electricity will be reduced less than 15% when 3 turbines are utilized.

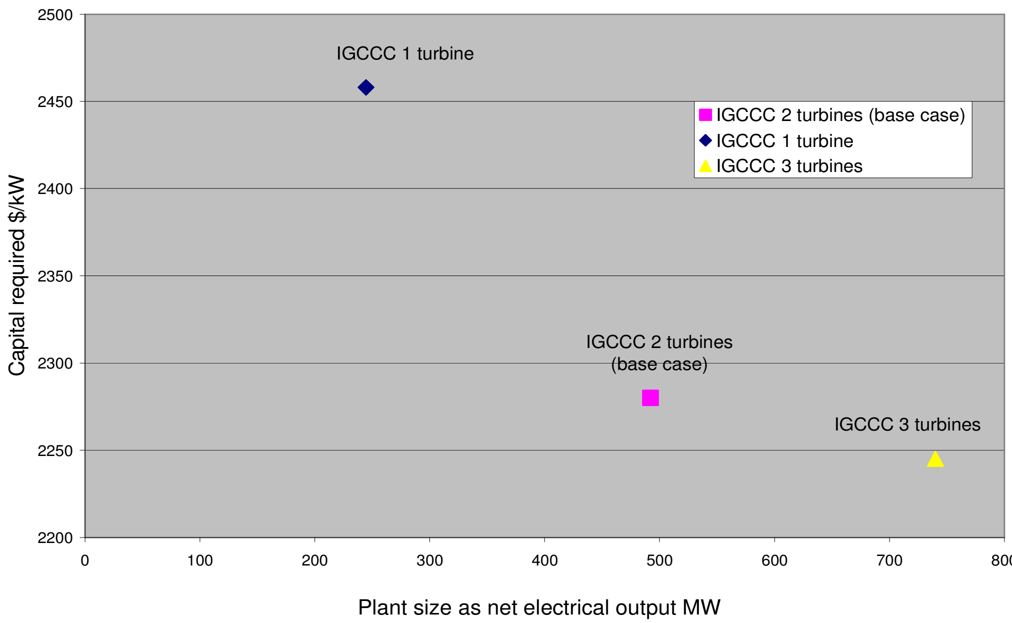

Figure 4.14: Effect of plant size (Net electrical output) on the Capital required of IGCC capture plant

4.5.3. Turbine inlet temperature

One of the key factors affecting the performance of the combined cycle power plants is the turbine inlet temperature. This temperature, as stated in sub-section 3.3.1, is a question of metallurgy e.g. the strength of the metal turbine blades and varies among the manufacturers. Changing the turbine inlet temperature is accompanied, above all, with changes in plant performance e.g. net electrical output, efficiency. The higher the temperature of the combustion gases entering the turbine, the higher the efficiency of the unit, i.e. the greater the work produced per unit of fuel burned[33]. An uncertainty has been applied to the inlet temperature via triangular distribution resulting in temperature range from 2033 °F (1112°C) to 2493°F (1367 °C) with a mode of 2420°F (1327 °C). The effect of this variation on the efficiency of NGCC plant with and without capture is shown in figures 4.15 and 4.16. This variation leads to almost 3% difference in the efficiency (HHV) for the non-capture plant as obvious from figure 4.15.

[33] Please refer to "Introduction to chemical engineering thermodynamics" by J. Smith, H.C. Van Ness and M.M. Abbott

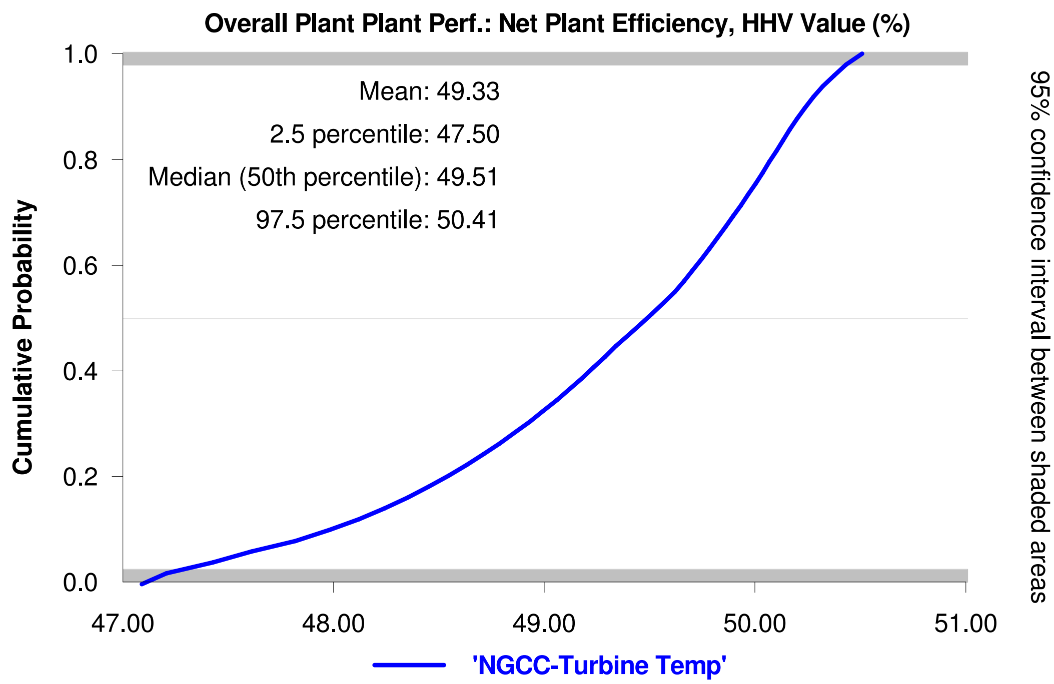

Figure 4.15: Cumulative probability of efficiency of NGCC plant with uncertain turbine inlet temperature

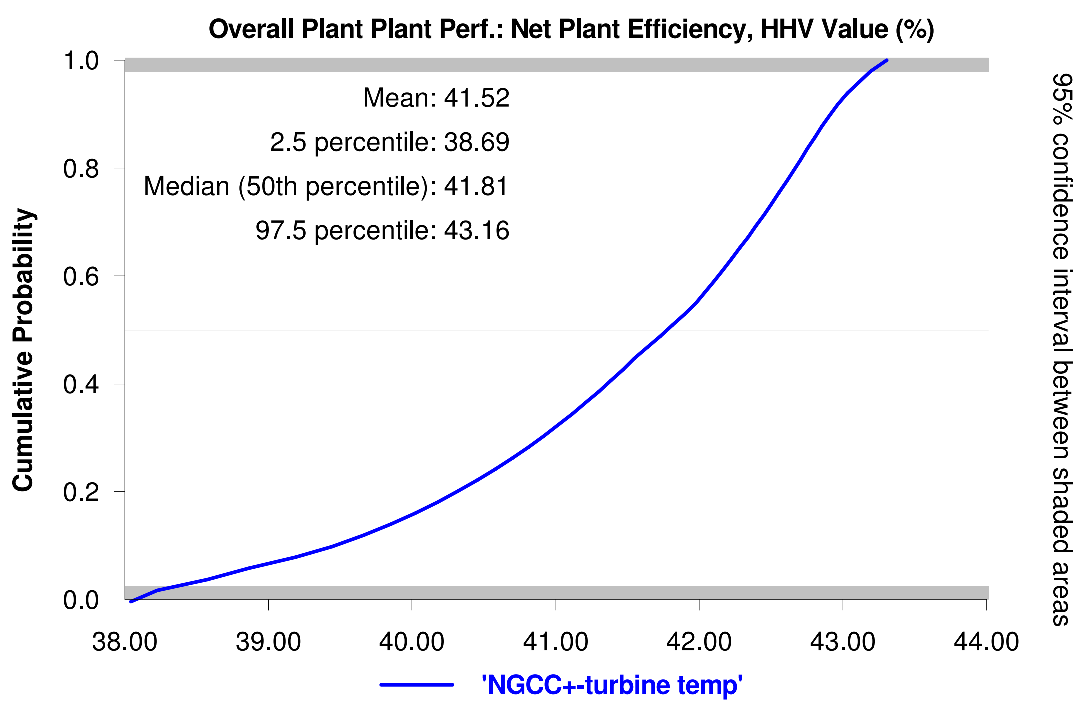

Figure 4.16: Cumulative probability of NGCC capture plant with uncertain turbine inlet temperature

Variable turbine inlet temperature also leads to variable emissions. Figure 4.17 shows CO_2 emissions of the NGCC base plant with variable turbine inlet temperature.

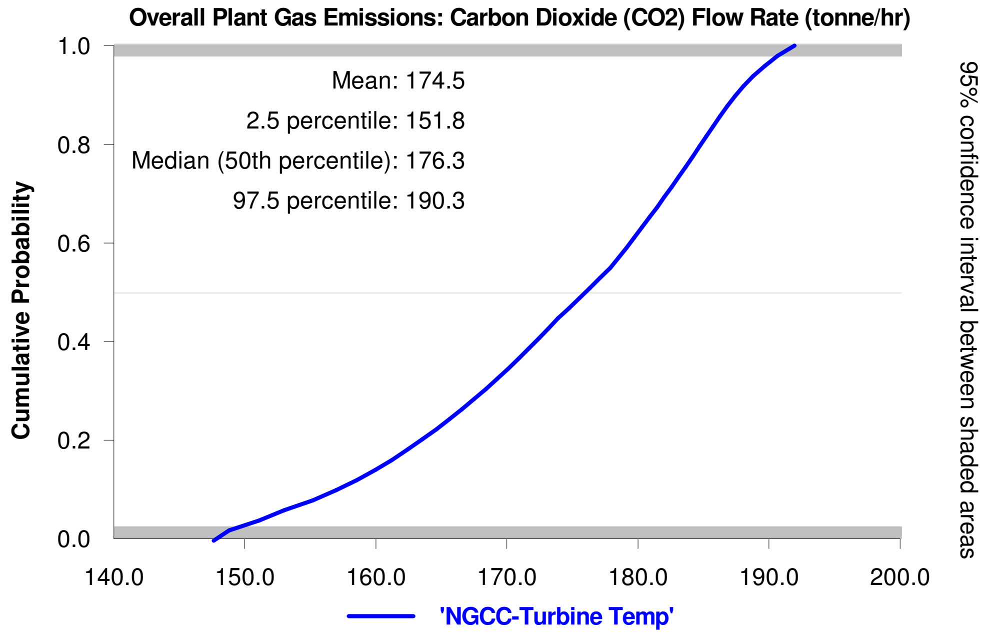

Figure 4.17: Cumulative probability of CO_2 emissions of NGCC plant with uncertain turbine inlet temperature

In addition to all the changes stated for plant without capture, the amount of captured CO_2 changes with altering turbine inlet temperature in the case of capture plant (figure 4.18).

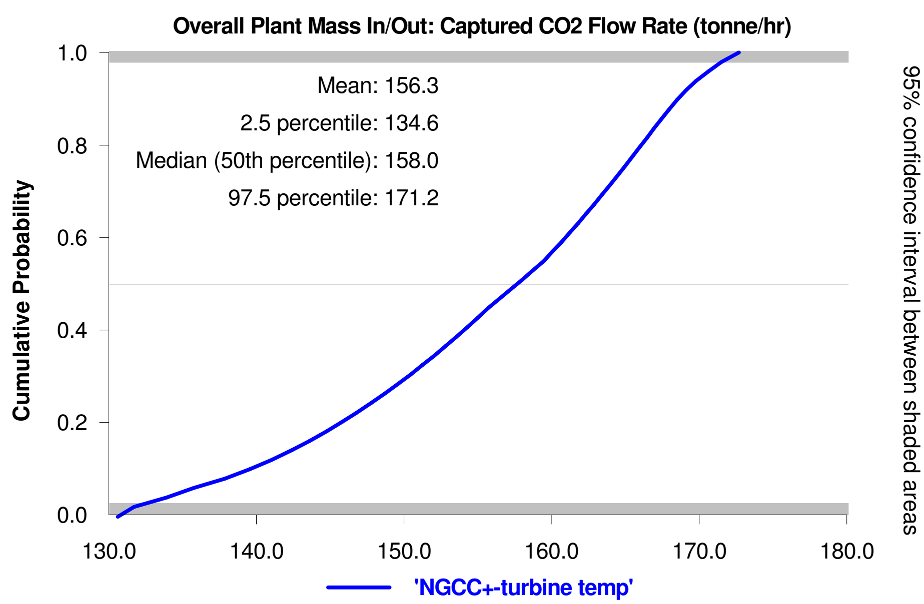

Figure 4.18: Cumulative probability of Captured CO_2 of NGCC capture plant with uncertain turbine inlet temperature

For IGCC plants, almost the same conclusions are obtained when the turbine inlet temperature changes. Figure 4.19 illustrates the efficiency of IGCC plant using Appalachian medium sulfur coal subject to this uncertainty.

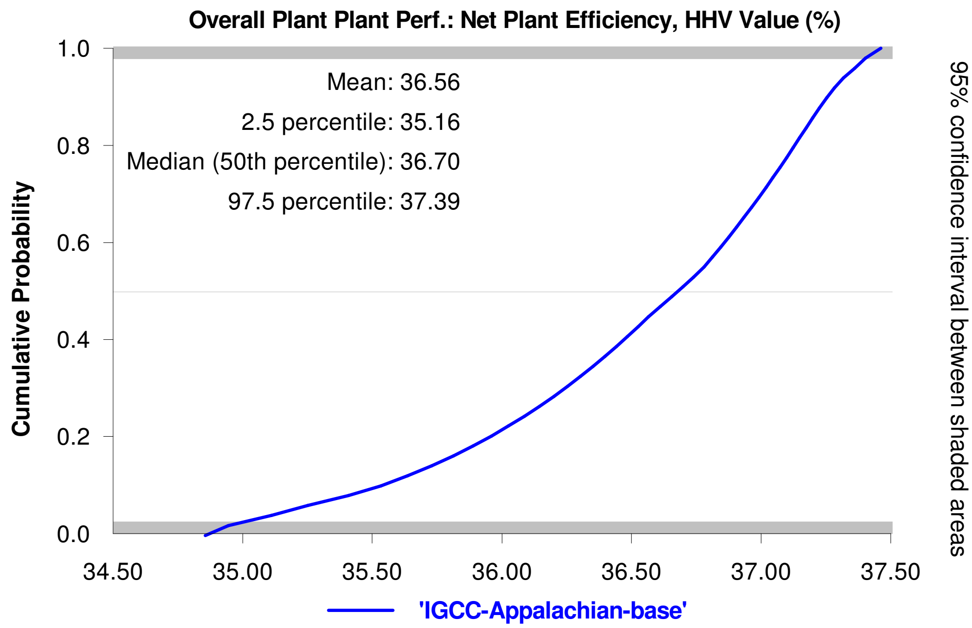

Figure 4.19: Cumulative probability of efficiency of IGCC plant with uncertain turbine inlet temperature (Appalachian medium sulfur coal)

The results from uncertainty analysis are useful for further sensitivity analysis in energy system in the next chapter.

Chapter 5: Energy-economics analysis

This chapter integrates the fossil fuel power plants into the energy-economics model REMIND, applying the techno-economic data from the previous chapters. REMIND model enables the user to evaluate different technologies regarding their share in energy sectors, their emissions together with consumption of primary energy, in a timely fashion. The experiments carried out in REMIND are either base experiments or the ones with sensitivity analysis. The base experiments are single-run experiments and involve parameterization of the technologies under study taking into account the variability of coal. These experiments are performed once following BAU (Business as Usual) emission scenario and once a scenario with a constraint on CO_2 emissions. The sensitivity analysis gives back information about the effect of parameters changing in a range of value on model outcome.

5.1. Introduction to *REMIND* model

REMIND is a global single-region *hybrid model* which comprises a top-down macroeconomic growth model (MGM) of *Ramsey type* and a *bottom-up* energy system model (ESM) with detailed technological resolution of the energy sector. Both models are solved simultaneously under a single objective function which aims at maximizing the intertemporal welfare under economic and technological constraints (labor and energy efficiency increase; resource and potential data; a CO_2 emission time path for policy experiments) On the other hand, *REMIND* allows the user to change the structure and adapt it to individual needs [25].

The macroeconomic growth model computes endogenously investments and interest rate and maximizes a non-linear intertemporal social welfare function depending on the consumption time path by allocating the budget between consumption and investment. Investments add to the capital stock which produces economic value in combination with labor [26].

The macroeconomic model and the energy system model are coupled in a hard link mode:

- The final energy demand – resolved by energetic and economic sectors – forces the usage and addition of transformation capacities in the energy system on the one hand, and is a factor in the macroeconomic production function on the other hand.
- Energy system costs include fuel costs, investments, and operation and maintenance, and need to be financed from the scarce macro-economic output [25].

The hard-link approach integrates the techno-economic constraints of the ESM into the MGM as an additional set of functions and constraints and solves one very complex non-linear programming (NLP) problem. The hard-link approach assures simultaneous energy and capital market equilibrium. Hence, the investment and technological choice is consistent with energy demand and capital supply as given by the macroeconomic system [26].

Both models are to find in figure 5.1 which provides the structure of *REMIND.*

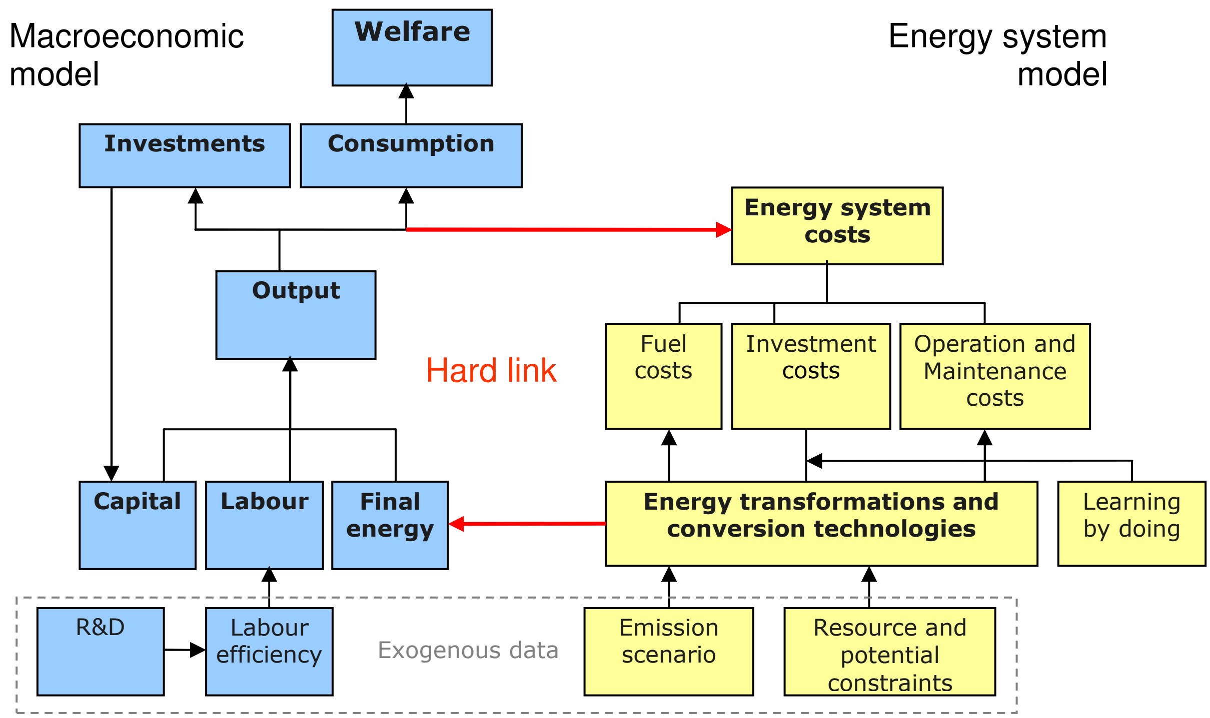

Figure 5.1: Structure of *REMIND* [25]

The hybrid model allows a detailed assessment of mitigation options:

- Changes of the technology mix to reduce the energy system's carbon intensity by applying nuclear energy, CCS, or renewables, or by a switch to less carbon intense fossil fuels
- Efficiency increases on the production side (e.g. usage of combined heat power plants)
- Energy type substitution (e.g. shift from heating oil to less carbon intense kinds of heat energy in the final energy mix)
- Energy substitution in the macroeconomic production factor mix [25]

The time period spans from 2005 (initial time step t_0) to 2150 (t_{end}). The time step is five years. A spin up from 1900 is done for the initial vintage structure of capacities. Time steps after 2100 are not taken into account for result interpretation to avoid misleading results from end effects.

5.1.1. Basic structure of the energy system model

In the energy system model, energy is represented by various types of primary, secondary and final energy:

- Primary energy: Primary energy sources, namely fossils (coal, crude oil, natural gas), uranium, and renewables (biomass, wind, water, solar, and geo energy)
- Secondary energy: Intermediate energy types or quantities which include heating oil, transportation fuels, purified gas, solids, electricity, district heat, and hydrogen

- Final energy: The end products of the energy system model which are ready to use for households, industry and transport (figure 5.2)

The primary energy types are transformed to secondary energy types via one or more technologies. Individual transformation processes in between are restricted by installed capacities. Investment costs for the addition of capacities can decline subject to learning effects, depending on the cumulated capacities. Emissions result from the transformation of primary to secondary energy; they can be stored via CCS (Carbon Capture and Storage) or be released to the atmosphere, restricted by an exogenous emission scenario. Besides capacity addition, costs arise from fuel extraction, and operation & maintenance. The final energy types distinguish the use of the respective secondary type for households, industry or transport. There is no exogenous constraints on the market share of a technology or the speed of capacity additions (for $t > t_0$). A basic structure of the model is shown in figure 5.2.

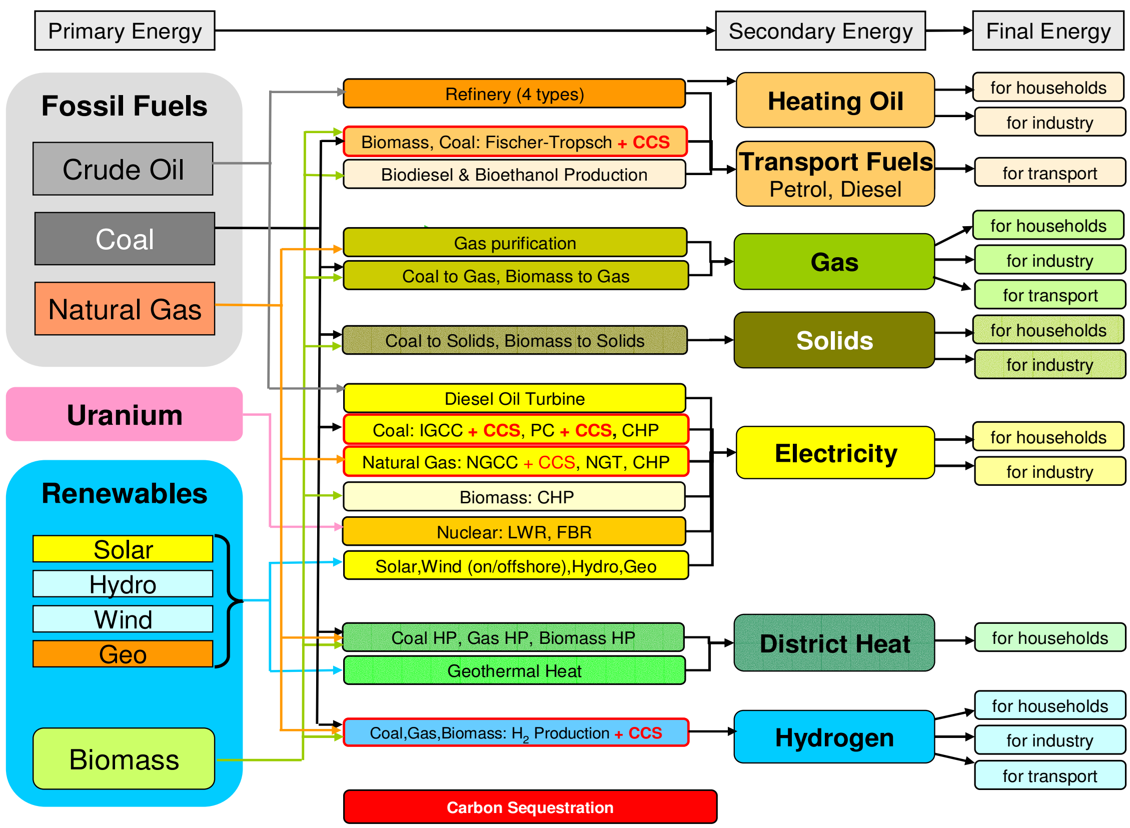

Figure 5.2: Structure of the energy system (energy types and transformation technologies), Source: Potsdam Institute for Climate Impact Research (PIK)

5.1.2. Parameters in *REMIND*

Below the parameters in *REMIND* which are of main interest for this thesis, are elaborated with their abbreviations and units. For more detailed explanation about the equations, settings and mappings in *REMIND* please refer to reference [33].

Specific cost data:

- Specific investment cost (**inco0**): investment cost per unit energy of the main product (*$/kW*)
- Fixed operation and maintenance cost (**omf**): share of the specific investment costs per year of operation (*no unit*)
- Variable operation and maintenance cost (**omv**): *$/kWa*

Technical parameters:

- Technical life time (**tlt**): time after which 100% of the installed capacity has been shut down (*yr*)
- Efficiency (**eta**): ratio of the main product to input (*no unit*)
- Availability factor (**nu**): real to rated capacity ratio (*no unit*)

Learning effects:

- Learning rate (**learn**): relative decrease of specific investment costs due to doubling of cumulated capacity (*no unit*)
- Reducible investment costs (**incolearn**): part of the specific investment costs that can be reduced by learning (*$/kW*)

Others:

- Stock size (**stockmax**): maximum amount of a quantity that can be stored at any time
- Cap on annual CO_2 emission (**co2max**): maximum annual CO_2 emission for each time step

Initial values and spin-up:

- Share of overall main product output at t_0 (**mix0**): the mix0 parameters are normalized to add up to one for each product (*no unit*)
- Cumulated capacity at t_0 (**ccap0**): only for learning technologies (*TW*)
- Capacity spin-up factor (**cap0**): describes when the initial capacity at t_0 has been added (this is necessary to determine the age structure of the technologies that are installed at t_0) (*no unit*)

Own consumption, couple production and emissions:

- Couple production / own consumption coefficient (**dataoc**): describes a couple product / own consumption stream as share of main product stream.
- Cumulated capacity in t_0 (**dataemi**): describes an emission stream as share of main product stream in GtC per TWa

5.1.3. The electricity sector in *REMIND*

The structure of the electricity sector in *REMIND* is important as it enables better interpretation and more precise judgment for the experiments. 20 technologies for electricity production are considered in *REMIND* which are shown in figure 5.3.

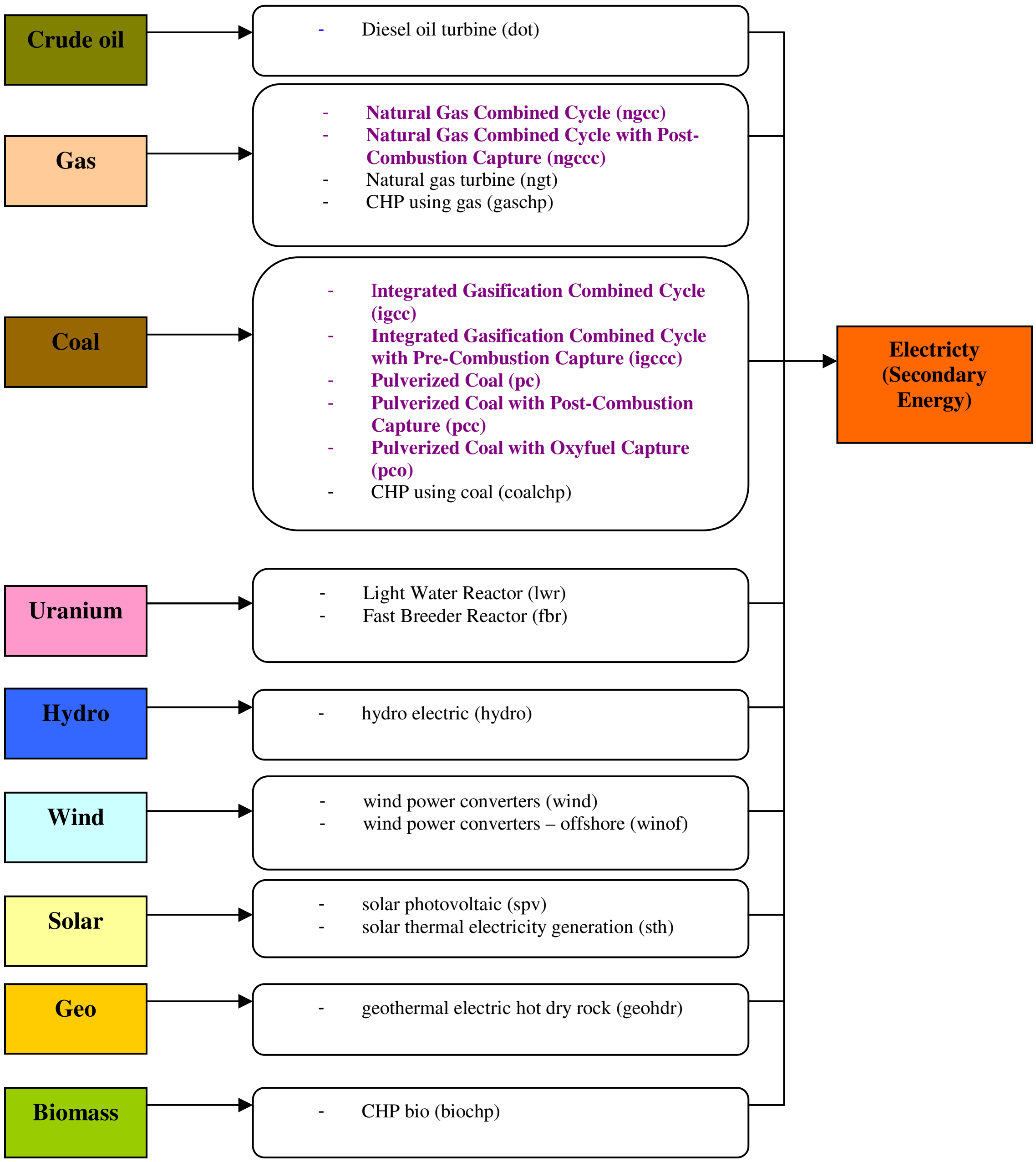

Figure 5.3: Electricity sector in *REMIND*

There are some technologies, which produce electricity as joint product in addition to their main product. The technologies that produce electricity as couple production are:

- coal to hydrogen (coalh2)
- coal to hydrogen with capture (coalh2c)
- coal based fischer-tropsch once through[34] (coalftot)
- coal based fischer-tropsch once through with capture (coalftcot)

[34] Once through concept is based on producing both FT liquids and electricity as couple product, whereas the recycle concept is focused on producing more FT liquids.

- biomass based fischer-tropsch once through (bioftot)
- biomass based fischer-tropsch recycle (bioftrec)
- biomass based fischer-tropsch once through with capture (bioftcot)
- biomass based fischer-tropsch recycle with capture (bioftcrec)
- biomass to ethanol (bioethl)

The model enables reducing carbon dioxide emissions in the electricity sector via the following mitigation options:

- Fuel switching: Coal can be replaced by natural gas which is less CO_2 intensive.
- Substitution by renewable energy: Fossil fuels can be substituted by renewable energy sources that do not rely on the combustion of carbohydrates. Examples of the technologies introducing the use of renewables are wind turbine, solar photovoltaic, etc.
- Substitution by nuclear energy: Nuclear fission is another energy source that does not produce direct CO_2 emissions. The technologies of choice are light water reactor and fast breeder reactor.
- Carbon Capture and Sequestration: Capturing CO_2 emissions and storing it underground is another possibility to reduce emissions and its application with fossil fuel-based power plants is the scope of this thesis. In addition to fossil fuel based power plants, there are some other technologies to which CCS can be employed. The examples are Fischer Tropsch technologies (biomass based and coal based) and coal to hydrogen.

The CCS chain considered in the model consists of the following parts:

- Compression of CO_2
- Transportation of CO_2
- Injection of CO_2
- Monitoring of CO_2

The parameters of the electricity generating technologies are listed in Appendix C.

5.2. Parameterization of fossil fuel based power plants with and without CCS in *REMIND*

Parameterization of the power plants is based on model results of IECM[35] and data from other references. For the NGCC and NGCCC the values of parameters are independent of the fuel type. For coal-based power plants, these values vary according to the coal quality, thus resulting in individual parameterization for each coal described in previous chapters.

5.2.1. Gas power plants parameters

Regarding the definition of the parameters and their units in the part 5.1.2, the following values have been chosen for NGCC modeling in *REMIND.* NGCC and

[35] In some cases there was a need to change, e.g. the efficiencies in REMIND are LHV and the emission coefficients are based on input.

NGCCC are considered to be learning technologies. For calculating the learning rates of the technologies ref. [27], [28] and [29] have been used.

	NGCC	NGCCC
Inco0 ($/kW)	665	1085
mix0 (-)	0.0631	0
eta (%)	0.54	0.46
nu (-)	0.75	0.75
omf (-)	0.021	0.024
omv ($/kWa)	5.21	8.19
incolearn ($/kW)	150	210
Ccap0 (TW)	0.1	0.01
learn (-)	0.03	0.05
CO2 emission (kgC/GJ)	14.2	1.42
CO2 captured (kgC/GJ)	-	12.79

Table 5.1: NGCC and NGCCC Techno-economic parameters in *REMIND*

In the above table, the captured and emitted CO_2 are expressed as emission coefficients in kg carbon per GJ which corresponds to secondary energy electricity production from primary energy natural gas with NGCC and NGCCC technologies.

5.2.2. Coal power plants parameters

Due to the fact that the coal quality can affect the performance, costs and emissions of the coal-based power plants, each of the coals in this thesis has its own parameterization in *REMIND.* This makes the interpretation of the model results more accurate. Tables 5.2 and 5.3 provide the techno-economic parameters and emission coefficients of coal-based power plants (IGCC, IGCCC, PC, PCC and PCO) for different types of coal used in this thesis namely, Appalachian medium sulfur, Illinois #6, Wyoming Powder River basin and North Dakota lignite.

	IGCC				IGCCC			
	Appalachian[36]	Illinois[37]	PRB	lignite	Appalachian	Illinois	PRB	lignite
inco0 ($/kW)	1665	1890	1971	2837	2280	2712	2959	4626
mix0 (-)	0.0001				0			
eta (%)	0.41	0.38	0.36	0.27	0.36	0.32	0.3	0.22
nu (-)	0.75				0.75			
omf (-)	0.034	0.033	0.033	0.031	0.034	0.034	0.034	0.032
omv ($/kWa)	16.19	16.19	17.61	20.16	20.24	20.24	22.01	25.2
incolearn ($/kW)	500	550	600	700	845	1007	1099	1100
ccap0 (TW)	0.01				0.01			
learn (-)	0.06				0.07			
CO2 emission (kgC/GJ)	23.6	23.83	24.52	24.71	2.22	2.01	1.87	1.59
CO2 captured (kgC/GJ)	-	-	-	-	21.41	21.82	22.64	23.12

Table 5.2: IGCC and IGCCC Techno-economic parameters in *REMIND*

[36] Please note that in the whole thesis Appalachian refers to Appalachian medium sulfur
[37] Please note that in the whole thesis Illinois refers to Illinois#6.

	PC				PCC				PCO			
	Appalachian	Illinois	PRB	lignite	Appalachian	Illinois	PRB	Lignite	Appalachian	Illinois	PRB	lignite
inco0 ($/kW)	1500	1569	1441	1688	2539	2675	2737	2977	3057	3205	3252	3572
mix0 (-)	0.3872				0				0			
eta (%)	0.43	0.42	0.42	0.4	0.33	0.32	0.31	0.3	0.34	0.335	0.33	0.31
nu(-)	0.75				0.75				0.75			
omf (-)	0.033	0.033	0.027	0.032	0.032	0.032	0.031	0.031	0.033	0.033	0.033	0.033
omv ($/kWa)	21.59	21.59	22.04	23.03	58.82	58.82	60.04	62.75	30.52	30.52	31.15	32.56
incolearn ($/kW)	0				500	535	547	595	458	480	487	535
ccap0 (TW)	0				0.01				0.01			
learn(-)	0				0.05				0.05			
CO2 emission (kgC/GJ)	24.6	25.04	25.30	25.68	2.46	2.5	2.53	2.57	1.23	1.25	1.26	1.28
CO2 captured (kgC/GJ)					22.17	22.5	22.82	23.14	23.79	24.22	24.5	24.87

Table 5.3: PC, PCC and PCO Techno-economic parameters in *REMIND*

As the coals have different composition, they will also have different CO_2 emissions and emission coefficients respectively. As the coal price depends on the quality of coal, different cost of coal has been considered in *REMIND* (table 5.4). The coal price can eventually offset the high investment costs of low rank coals.

Primary Energy	Price ($/GJ)
Natural gas	3.50
Appalachian medium sulfur	1.50
Illinois#6	1.23
PRB	0.94
lignite	0.68

Table 5.4: Cost of natural gas and different coals in *REMIND*

5.3. Case studies

The case studies carried out in the thesis are focused on the fossil fuel-based technologies for electricity production to which CCS can be integrated. These are the technologies modeled in the previous chapters and are highlighted in figure 5.3. The case studies are categorized into base case studies and sensitivity studies. In each case study several experiments have been run which consequently establish the analysis basis. The user can define his own experiment by choosing different experiment options such as emission scenario (BAU and policy scenario 450 ppm), and switching on or off other mitigation options. The emission scenarios consider policy influences on the optimization problem. In the business as usual (BAU) case no emission constraints are imposed on the system. In case of policy scenario, a time path emission constraint stabilizes the CO_2 concentration at 450 ppm.

5.3.1. Base case study

The base case study refers to the cases where no uncertainty is applied to the power plants, and therefore the parameters have one single value.

In the base experiments, it is assumed that the nuclear, CCS, solar options and the Fischer Tropsch technology (both concepts of once- through and recycle) are in action. These experiments are carried out for different types of coal, as the characteristics of the coal (such as emissions and cost) and the technology parameters differ correspondingly, thus revealing the effect of variability of coal on the whole energy system.

All the base experiments have been done once with BAU (Business As Usual) scenario and once with policy scenario 450 ppm with exogenous constraint on maximum annual emissions pathway that leads to stabilization of atmospheric CO_2 concentrations at 450ppm. Among the various results obtainable from the experiments, the electricity production, coal consumption, and CO_2 emissions are of topical interest for this thesis in the most cases. The results enable the user to evaluate different contributing technologies[38] over a long time scale. One other observed phenomenon in the policy 450 ppm experiments is how or whether the different CCS options contribute to reducing CO_2 emissions in the context of other mitigation options in different time steps. Since the base experiments have been carried out for each coal with its relating parameters, the results also reflect how and to what extent variability of coal can effect the technology selection. Appalachian medium sulfur has been chosen as reference coal in the result interpretations. Comparison with other coals is provided when needed.

5.3.1.1. BAU Scenario experiments and results

In BAU experiments, no emission constraint is applied to the technologies. The first result of interest is the electricity generation mix. Figure 5.4 outlines the share of different power generating technologies available in the model as well as the ones with couple production for Appalachian medium sulfur. According to this figure, for Appalachian medium sulfur coal, starting from year 2005 model shows tendency towards NGCC and PC, this will be then replaced by IGCC plants from the year 2050 which is mainly due to the learning effect of IGCC plants resulting in investment costs reduction. It should be noted that the model is very sensitive with respect to learning effects of IGCC, meaning that lowering the reducible investment of IGCC plants due to learning can result in favoring the PC over IGCC. This fact is studied later on under sensitivity analysis. IGCC plants have a great share in electricity production with their peak of almost 50% in 2080 which is then decreased with the increasing effect of solar photovoltaic[39].

[38] As high steel prices are considered in PC, IGCC and NGCC power plant costs, the investment costs of technologies using coal and/or producing electricity have been scaled up to 30% to ensure the consistency in the results.

[39] Please refer to figure 5.3 or appendix B to the see the definition of the abbreviations in the plots.

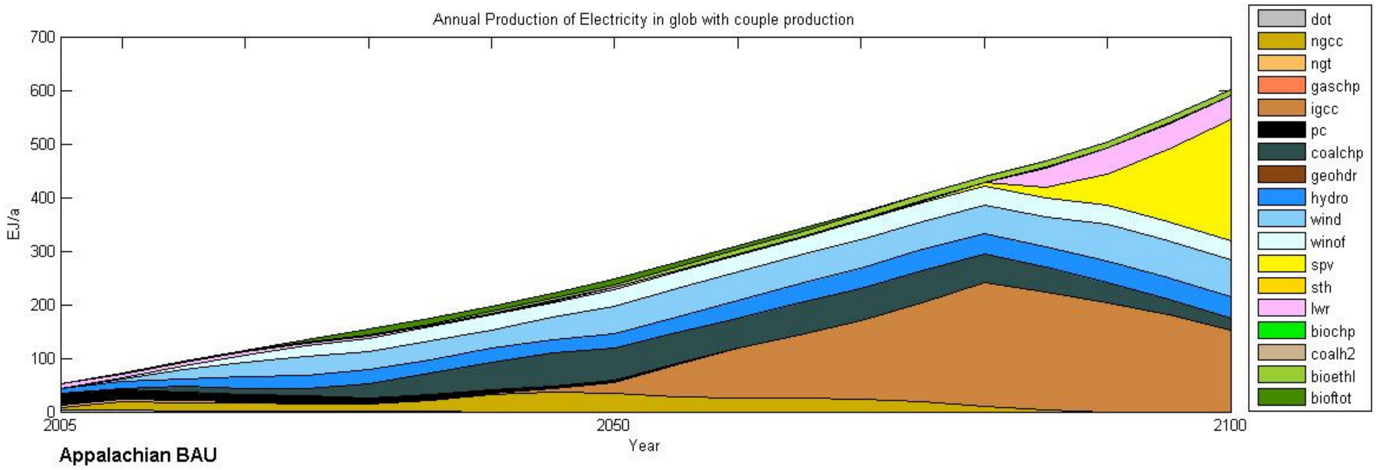

Figure 5.4: Annual production of electricity of all technologies including the ones with couple production, Appalachian medium sulfur coal, BAU scenario

Figure 5.5 shows the electricity generation mix when other coals are used in the model. As clear from this figure, the choice of technology is highly dependant on the type of coal. Taking into account figure 5.5, one can conclude that for other coals, IGCC will not be a technology of choice anymore. For Illinois #6, NGCC is the dominant technology of choice in BAU scenario. This is true although the coal price is cheaper compared to Appalachian medium sulfur coal. The reason can be mainly the higher efficiency and lower investment costs of NGCC. For PRB coal, the model tends towards PC technology which is mainly due to lower cost of coal and lower investment costs of PC plants when this coal is used. One can also conclude that even NGCC is not competitive with PC in BAU scenario in this case. Using lignite as coal results in employing to higher amount PC and Coal combined heat and power (coalchp) and to relatively lower amount NGCC at the beginning of the timeframe, followed by using mostly NGCC with a highest share of 45% in 2070. This is an interesting fact which is not expected as the price of coal is the lowest (compared to other coals) and equals almost half the price of Appalachian medium sulfur coal.

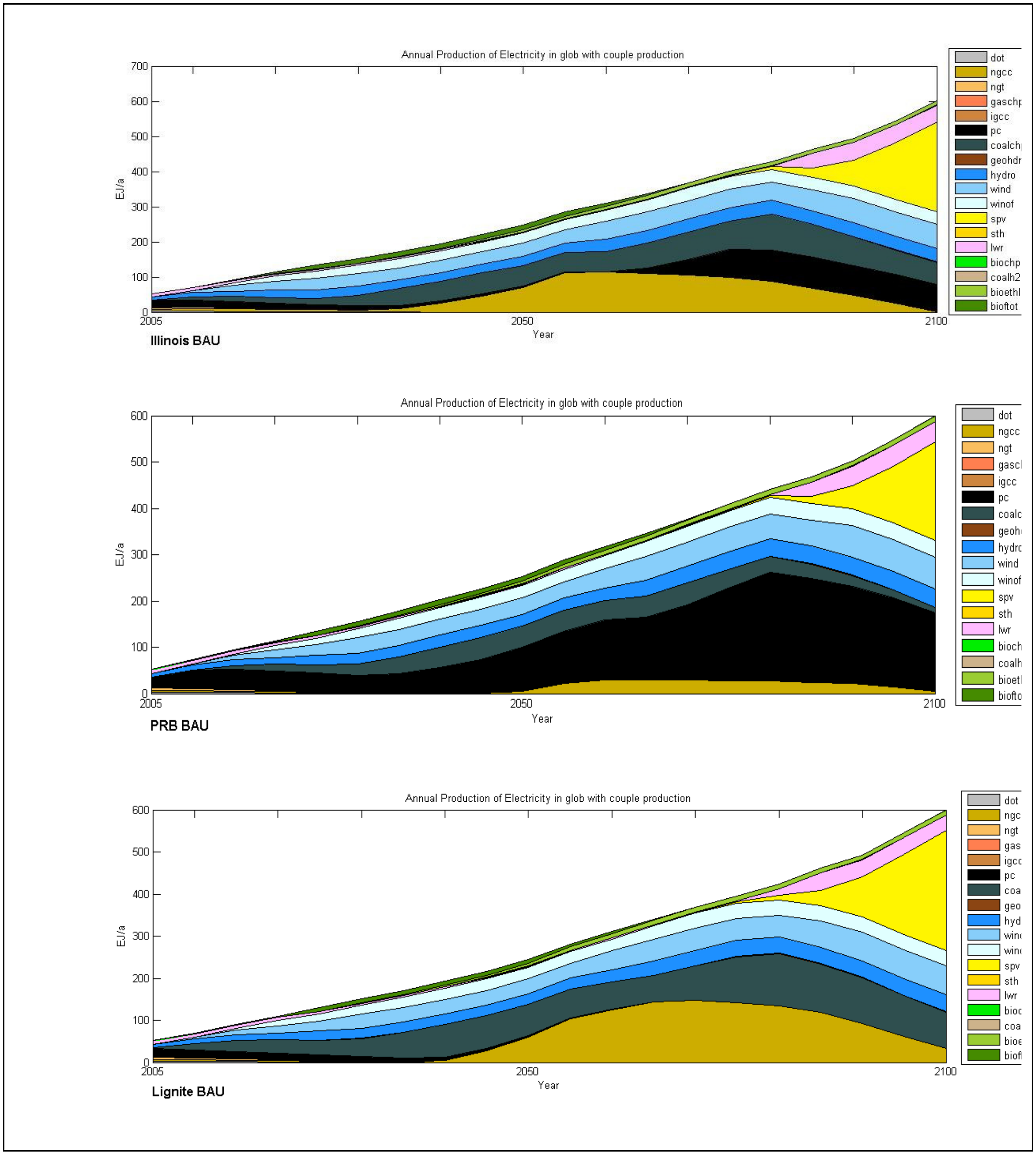

Figure 5.5: Annual production of electricity of all technologies including the ones with couple production, Illinois#6, PRB and Lignite coal, BAU scenario

For better interpretation regarding variability, more detailed information about the amount of electricity produced, electricity generation mix and the allocation of coal among coal consuming technologies are required. In this regard, table 5.5 shows the cumulative electricity production for different time steps relative to the coal type.

	Appalachian medium sulfur	Illinois #6	PRB	Lignite
2010	123.4811	122.5825	124.6421	120.8739
2030	621.1086	616.1682	622.8829	602.5198
2050	1461.493	1452.182	1482.905	1426.164
2070	1740.96	1736.839	1770.834	1707.933
2100	2051.213	2047.025	2087.04	2018.78

Table 5.5: Cumulative Energy system electricity production relative to the coal type used in the system (EJ)

On the whole, it can be reasoned out from table 5.5 that as the heating value of the coal decreases, the cumulative electricity production of the energy system using this coal is also reduced. However, PRB should be excluded from this conclusion. This coal leads to the highest electricity production when used in the model (even more than Appalachian medium sulfur). This, as will be seen later, has to do with the enormous allocation of this coal in PC power generation.
Besides, it is essential to know to what extent each power generating technology plays a part in electricity production. For this reason, figure 5.6 illustrates the share of all participant technologies in the electricity production mix till 2050 considering the coal type.

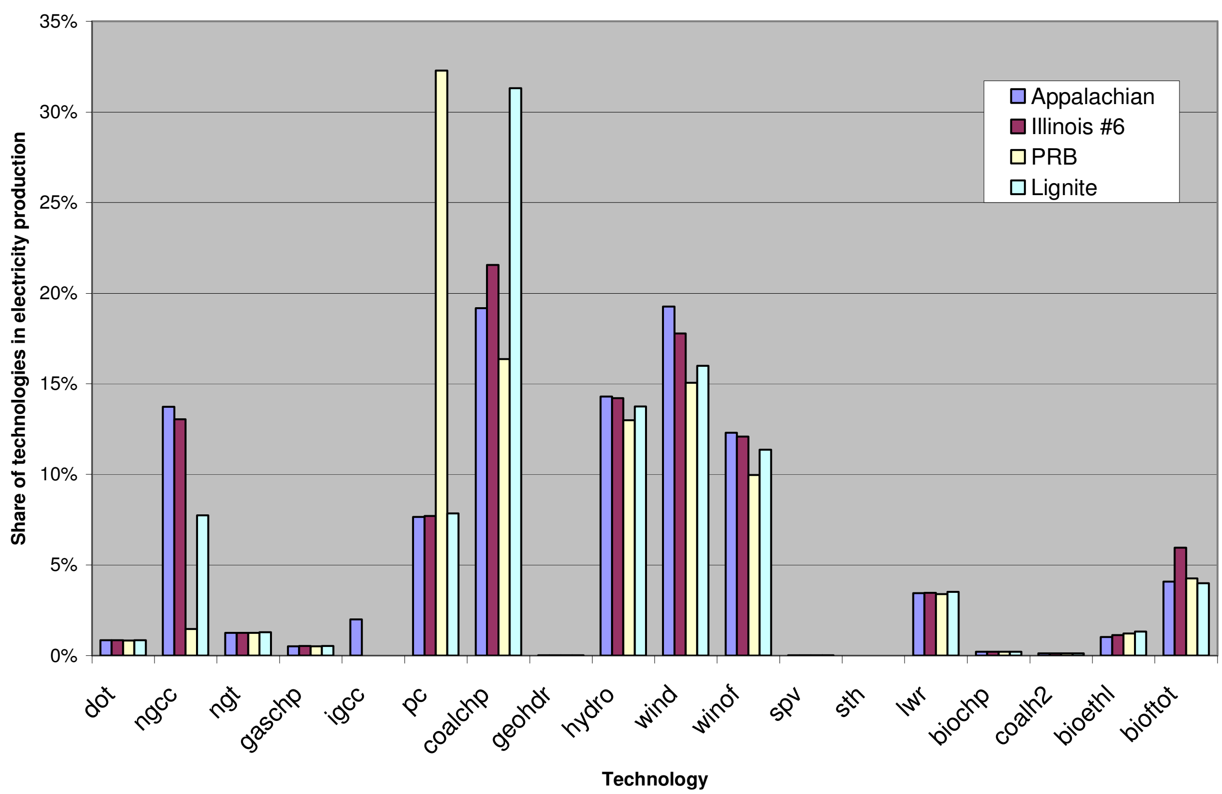

Figure 5.6: Electricity generation mix of all electricity generating technologies in *REMIND* till 2050-BAU Scenario (All coals)

Regarding figure 5.6, some exciting phenomena are realized. One can realize that how the share of technologies in electricity production changes when the coal type changes. Choosing the bituminous coals, namely Appalachian medium sulfur and Illinois #6 will result in almost similar electricity mix. In case of Appalachian medium sulfur, share of NGCC and IGCC are the highest. The share of Illinois #6 will be higher in coal combined heat and power (coalchp) relative to Appalachian medium sulfur and more biomass Fischer Tropsch once through technology (bioftot) is used comparing the others. It is also worthy of note that in the case of PRB coal, up to 33% of the electricity is produced via PC technology. The coal combined heat and power (coalchp) is also a dominant electricity generation technology especially in case of lignite with a share of 31%.

It is also interesting to tell how coal is apportioned among the coal consuming technologies and how the coal type affects this distribution. The coal consuming technologies are not only specific for power sector; they are also used for production of other types of secondary energies such as heat, solids and transport fuels. In this regard, figure 5.7 shows the coal consumption by technology for different types of coal whereas figure 5.8 illustrates the share of coal consumption by technologies till 2050.

Concerning figure 5.7, the allocation of coal in coal power plants is a question of time and the type of coal. Coal is not only utilized in the electricity sector, but also for other secondary energy production; especially solids, gas, and transport fuels. Among different coal types, Appalachian medium sulfur and PRB are dedicated for electricity production.

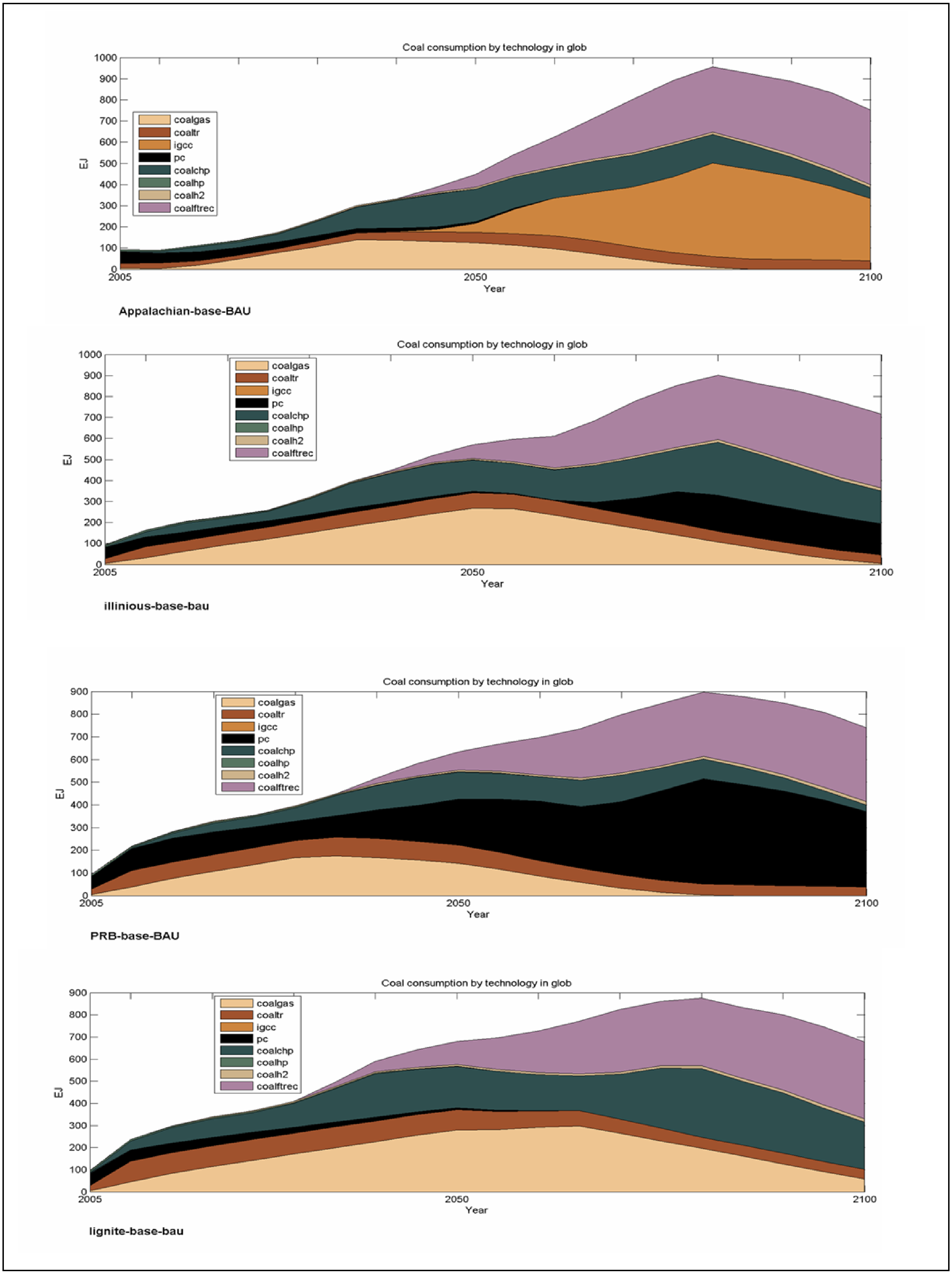

Figure 5.7: Coal consumption by technology- BAU Scenario, all coal types

For exact analyzing, figure 5.8 indicates the coal consumption mix by technologies until 2050.

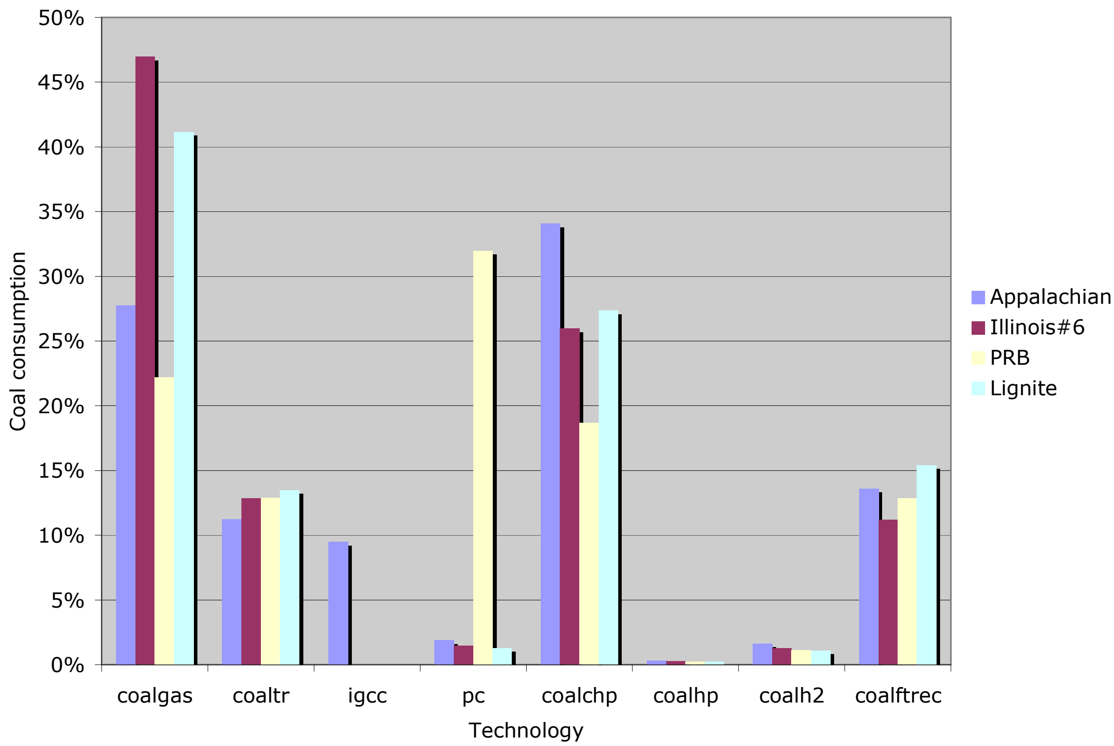

Figure 5.8: Share of coal consumption by technologies till 2050 – BAU Scenario (all coals)

This figure points out that among the coal consuming technologies[40], there are some technologies which use large amount of coal regardless of the coal type (although the extent of usage is different) and there are some other technologies which prefer to use specific type of coal. Aside from coal combined heat and power (coalchp), coal is considerably used in other sectors rather than electricity sector, e.g. in coal gasification (coalgas), coal transformation (coaltr), and coal Fischer Tropsch recycle (coalftrec). The only coal used in IGCC technology is Appalachian medium sulfur. The PC technology is also worth considering in the case of PRB coal. Illinois#6 and lignite have the highest usage in coal gasification. They are also well used in coal combined heat and power and also in production of transport fuels by Fischer Tropsch technology. Although PRB and Appalachian are the coals which preferably produce electricity (also see table 5.5), their shares in other sectors are also considerable (e.g. in transport sector or solids).

Another important issue is the total consumption of the coal as an energy resource. Figure 5.9 shows the coal consumption of all coal types in different time steps.

[40] Please refer to Appendix C to see the parameters of these technologies,

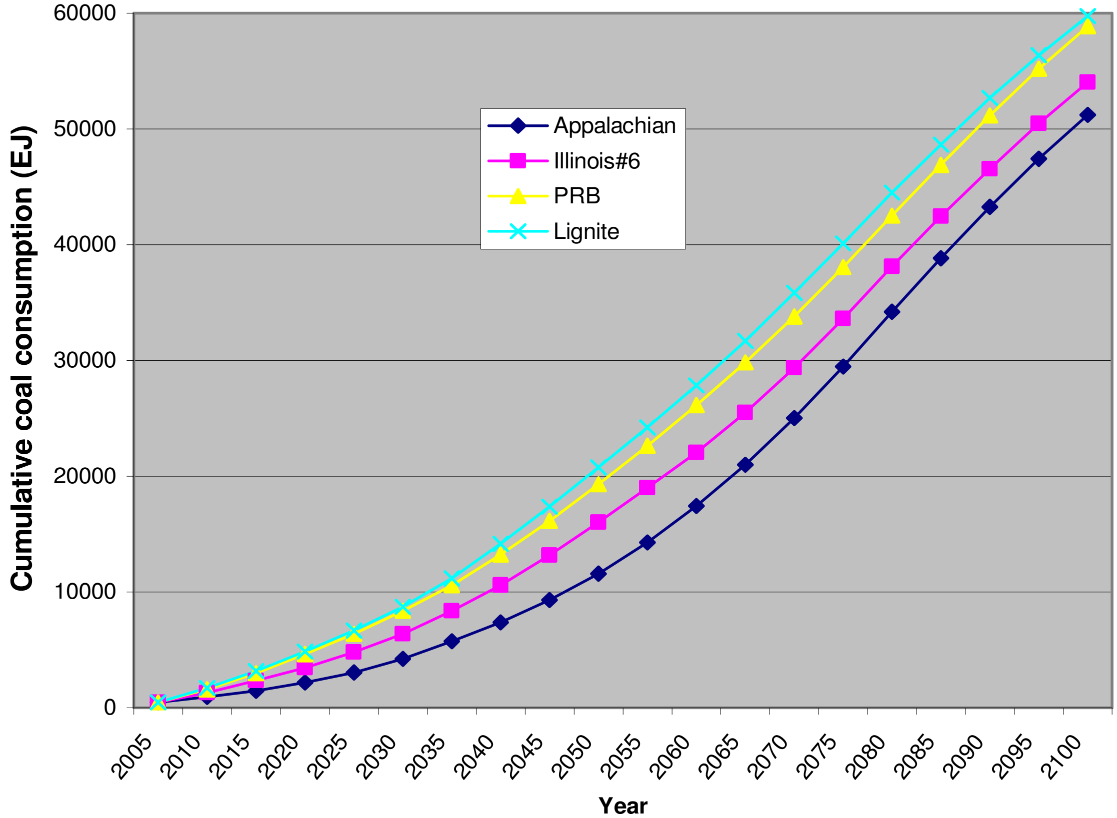

Figure 5.9: Total cumulative coal consumption of all coal types in different time steps

As made clear from figure 5.9, lignite has the highest cumulative consumption in comparison to other coal types. That can be due to the cheap price of this coal and also more mass flow rates required for better performance in technologies. Taking into account the electricity production in table 5.5, it is also worth mentioning that Appalachian medium sulfur produces high amount of electricity although its consumption is the least. The reason might be the higher efficiency of the coal consuming technologies when using this coal which means at the same time less coal input is required to produce the proposed amount of electricity compared to other coals. The higher costs of this coal play an important role in this coincidence.

As no emission constraint is applied in BAU scenario, the CO_2 emissions path is also an appealing result. Figure 5.10 shows the annual CO_2 emissions by secondary energy for various sectors when the coal used is Appalachian medium sulfur coal. The black line shows the emission constraint in policy scenario and the green one the total emissions. In BAU scenario, the phenomenon observed is that the green line appears always above the black line. In other words, CO_2 emissions exceed the constraint of policy scenario (450 ppm). Interestingly, the CO_2 emissions from the electricity sector (blue line in figure 5.10) would solely be enough to surpass the emission constraint. This result holds for all types of coal, although the amount of emissions in electricity sector varies with the coal type. For instance, lignite coal shows lower emissions in electricity sector comparing Appalachian medium sulfur or PRB.

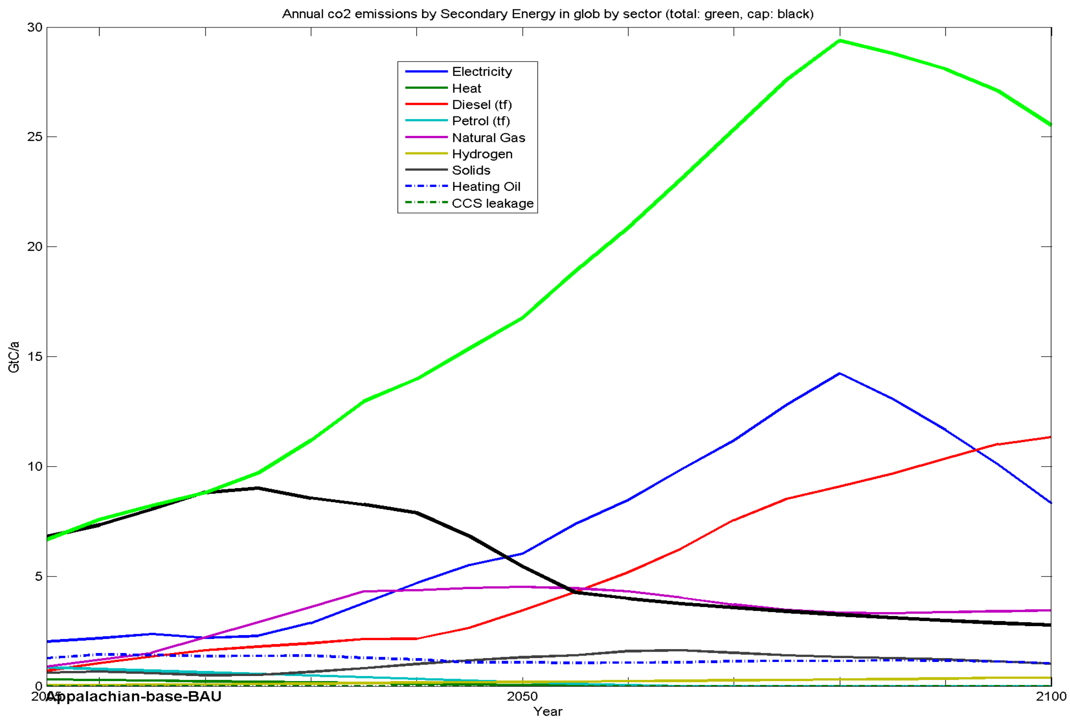

Figure 5.10: Annual CO_2 emissions by secondary energy for various sectors (Coal: Appalachian medium sulfur)

Furthermore, *REMIND* delivers also the electricity price which can be calculated with different discount rates. The electricity production cost is composed of investment, O&M and fuel cost components. The COE as model result of IECM can be compared at this stage. As Appalachian medium sulfur is considered as reference coal in this thesis, the electricity production cost for years 2005, 2050 and 2100 with 5% discount rate is discussed when model uses this coal and the graphs for years 2005 (figure 5.11) and 2050 (figure 5.12) are presented below.

Considering figure 5.11 which indicated the electricity cost for 2005, one can view that NGCC offers the cheapest electricity production cost compared with PC and IGCC – which was also concluded from IECM-, but still hydro is competitive with this technology as it doesn't face the high fuel price. Electricity production cost is to slightly lower in the case of PC than IGCC. But when the capture is applied, IGCC offers cheaper price relative to PCC and PCO. The time influence on COE is to observe in figure 5.12 for year 2050. Considering the cost of electricity production in longer time steps, the gap of COE between NGCC and coal-based power plants narrows and they all offer more or less the same electricity cost of 3.5 ct/kWh in 2050 and 4.8 ct/kWh in 2100. The most important factor resulting in the higher electricity production cost in the case of NGCC plants is the high natural gas price in the future.

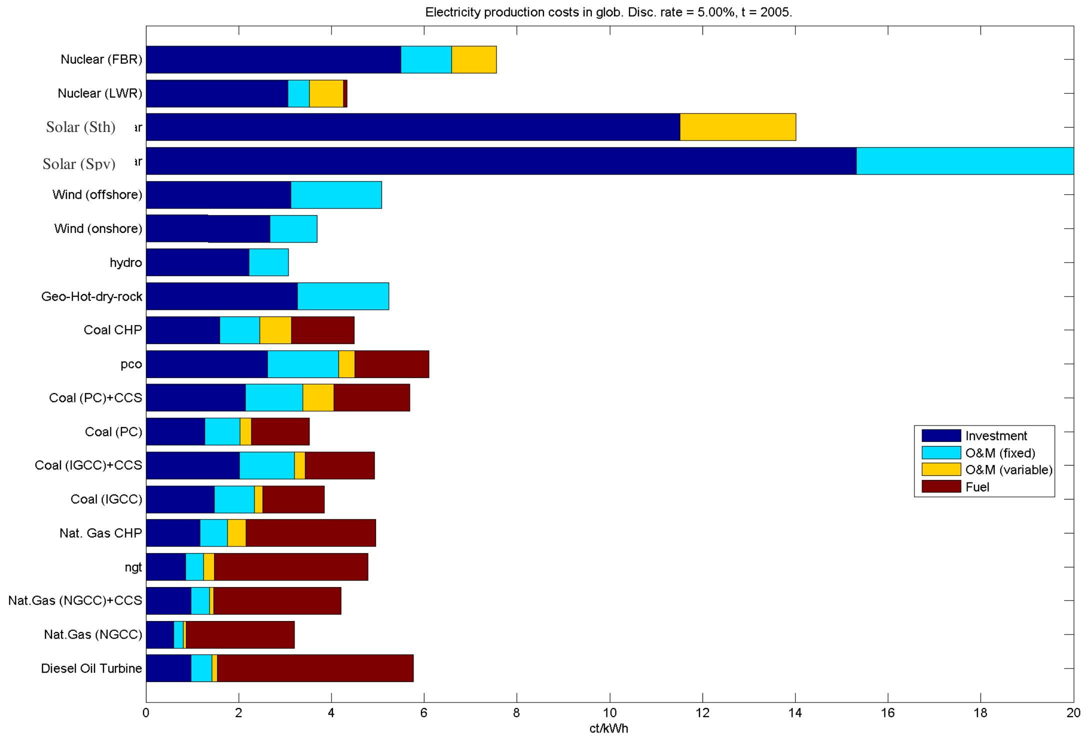

Figure 5.11: Electricity production costs, Discount rate 5%, t=2005, Appalachian medium sulfur coal

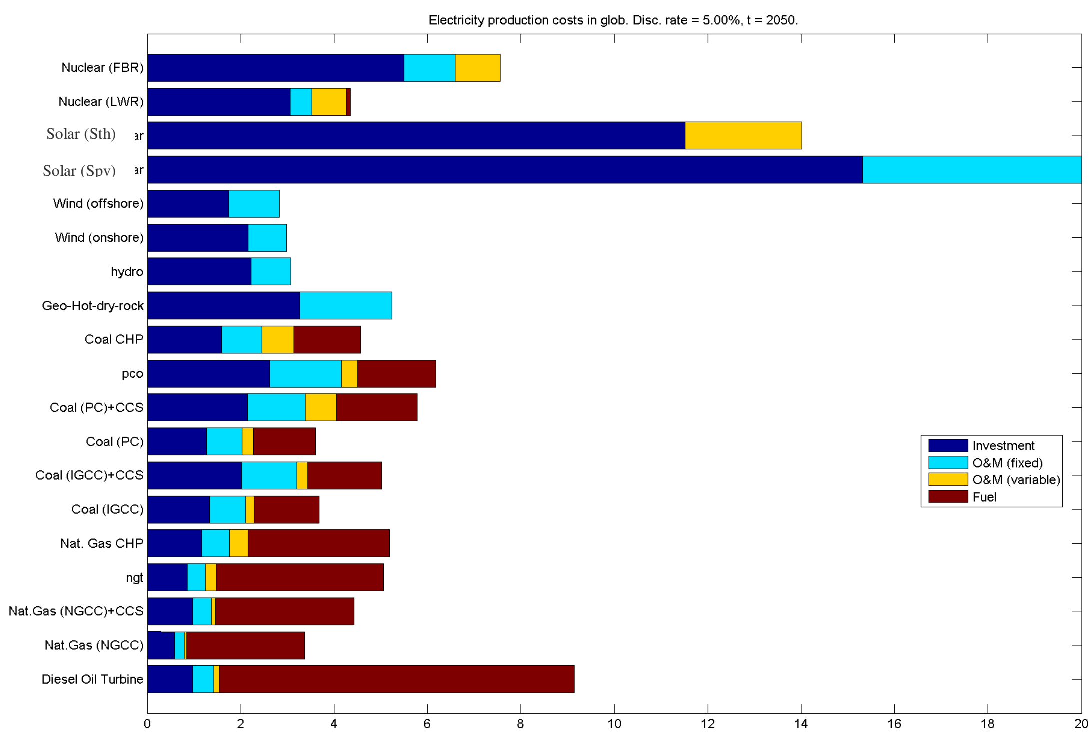

Figure 5.12: Electricity production costs, Discount rate 5%, t=2050, Appalachian medium sulfur coal

5.3.1.2. 450 ppm Policy Scenario experiments and results

When the policy scenario is employed, the mitigation options merge in the model results to help reducing the CO_2 emissions up to 450 ppm. The present thesis focuses distinctively on the contribution of CCS as mitigation option.

When Appalachian medium sulfur is chosen as coal in the model, the tendency towards CCS options and solar energy for electricity production is spectacular. This fact is illustrated in figure 5.13 which shows the electricity production for this case. Among the CCS options, the model favors IGCCC to a great amount especially in the middle of the timeframe. The contribution of NGCC post-combustion starts from 2050. After 2070, the share of IGCC pre-combustion decreases with increasing influence of renewable energy sources. At the end of the timeframe IGCC seems to be not anymore competitive with solar photovoltaic.

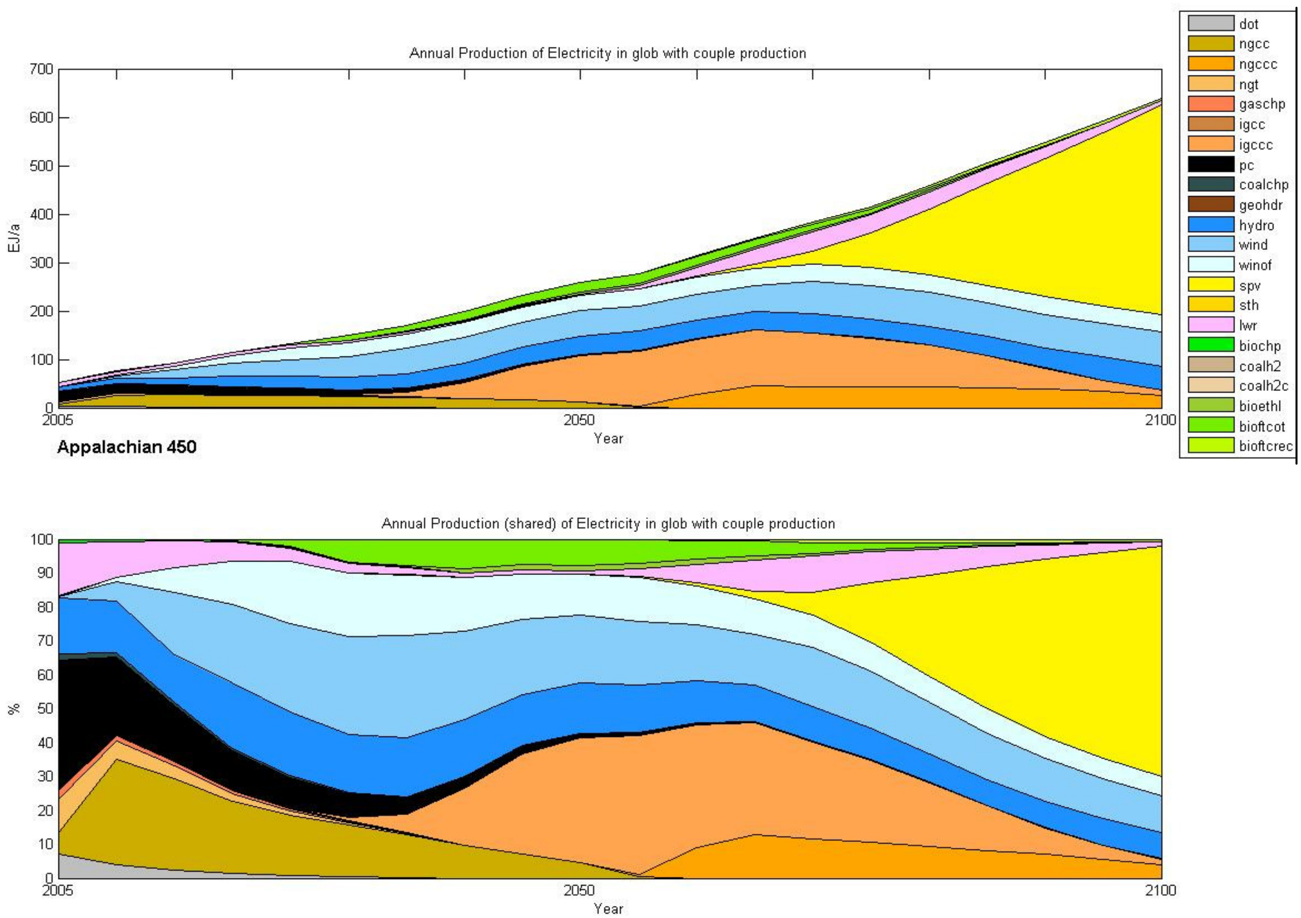

Figure 5.13: Annual production of electricity of all technologies including the ones with couple production, 450 ppm policy scenario, Appalachian medium sulfur coal

To see how the coal type affects the electricity production mix, figure 5.14 indicates the electricity production in 450 ppm policy scenario with PRB. The profound contribution of renewables such as solar energy and wind is spectacular. Among the CCS technologies the model prefers NGCCC to coal capture plants.

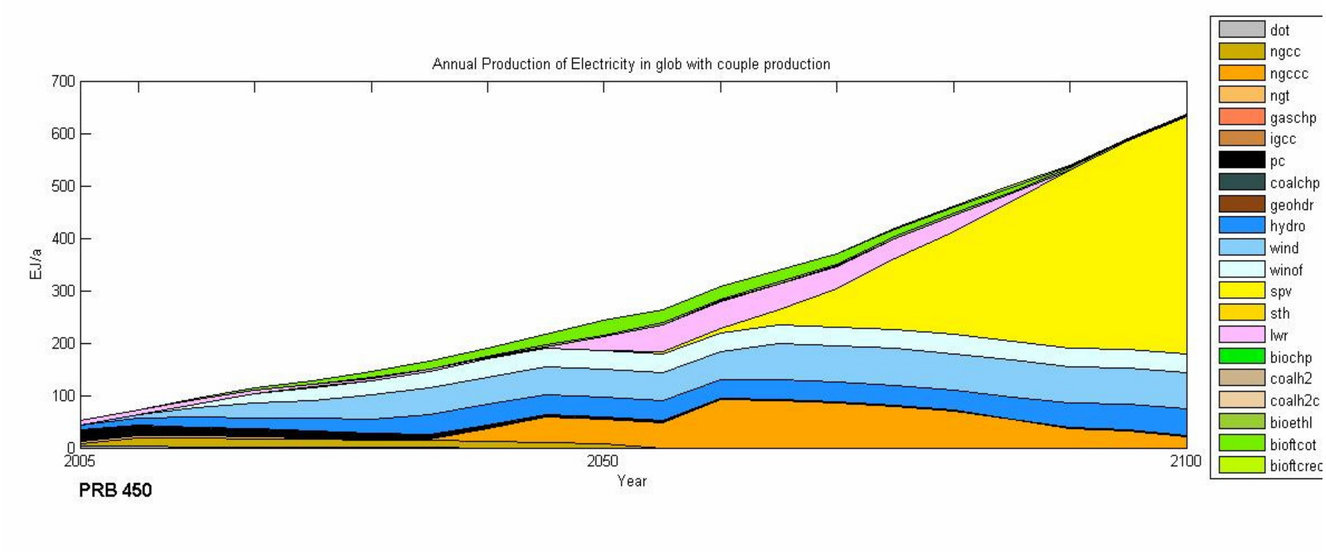

Figure 5.14: Annual production of electricity of all technologies including the ones with couple production, 450 ppm policy scenario, PRB coal

In order to better comprehend the model behavior relative to variability of the coal type, picture 5.15 shows the share of technologies in electricity production till 2050.

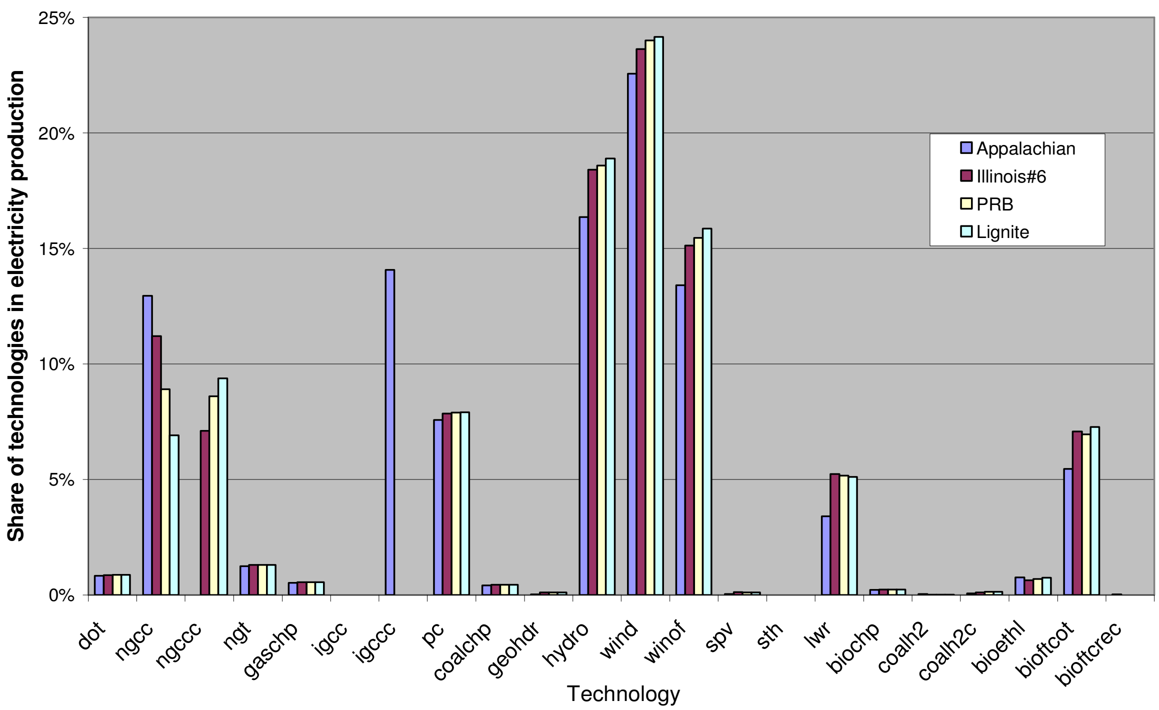

Figure 5.15: Electricity production mix of all electricity generating technologies in *REMIND* till 2050-Policy Scenario (All coals)

According to figure 5.15, when the model is subject to policy scenario, the wind energy (both onshore and offshore) and hydro energy are dominant in providing the world with electricity. This result can be generalized to all coals, taking into account that the share of these renewable energies decreases as the rank of coal increases. Share of NGCC in electricity production decreases with decreasing heating value of the coal. It is notable that for NGCC capture plant, the adverse conclusion is valid, meaning that for Appalachian medium sulfur NGCCC is not a technology of choice till 2050, and actually IGCCC is favored by the model. For other, coals the share of NGCC capture increases as the quality of coal decreases. Share of PC plants in electricity production is also worth considering and is almost the same for all coal types. By applying constraints to CO_2 emissions in the model, the biomass based Fischer Tropsch once through technology with capture (bioftcot) becomes more attractive. Contribution of nuclear energy in electricity production is not high (almost 5%) but still relevant.

In addition to electricity mix, coal consumption mix among the coal consuming technologies in Policy scenario (figure 5.16) and the comparison between BAU and Policy scenario in this regard (figure 5.17) are engaging issues.

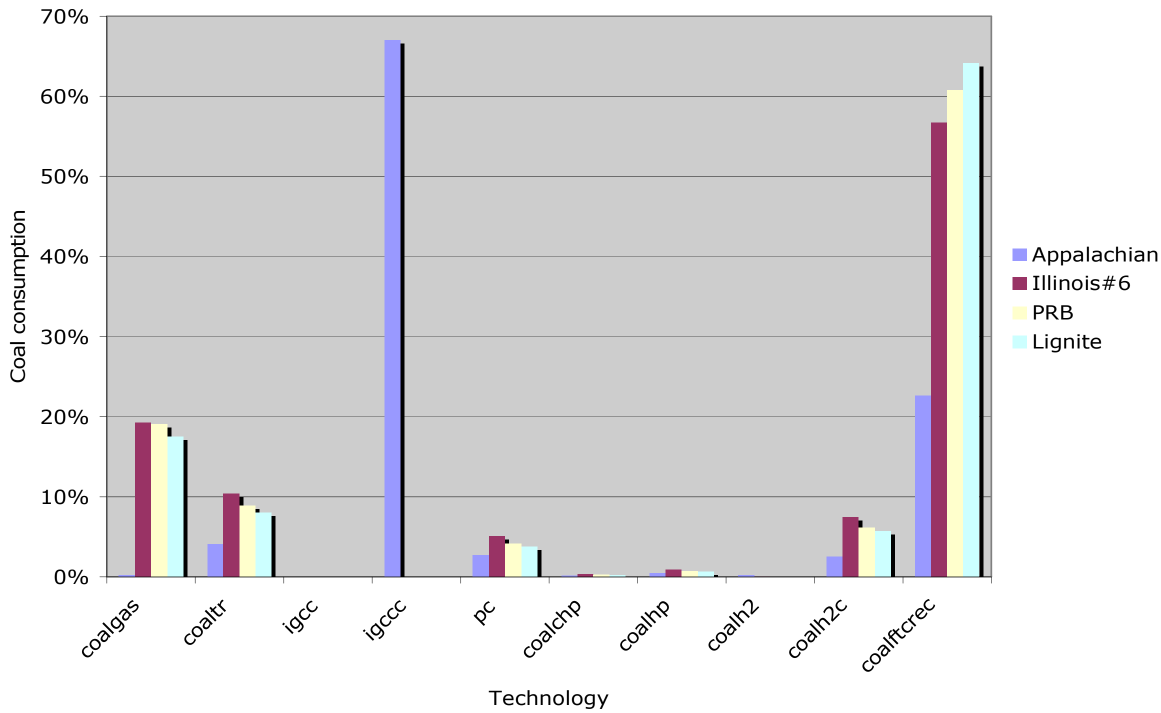

Figure 5.16: Share of coal consumption by technologies till 2050 – 450 Scenario (all coals)

Due to figure 5.16, IGCC pre-combustion technology uses up to 67% of coal, when Appalachian medium sulfur is the coal in the model. For the rest of the coals the model behavior is different. Apart from PC technology, no other coal consuming technology tends to use coal for electricity production. Coal is mostly used in transport sector to produce diesel via coal Fischer Tropsch technology. The next technology favoring coal (apart from Appalachian medium sulfur) is coal to gas (coalgas). This fact that coal (apart from Appalachian) is not a primary energy source to produce electricity is worth noticing. This means that electricity is produced rather by the energy carriers which are more environment-friendly. Figure 5.17 affirms this fact by comparing coal consumption for both scenarios till 2050.

As evident from this figure, the usage of coal will be reduced significantly in 450 ppm scenario. For Appalachian medium sulfur this reduction amounts to 43%. For low rank coals this reduction is even more spectacular. For lignite coal, for instance, the coal consumption will be halved in 450 ppm scenario relative to BAU scenario.

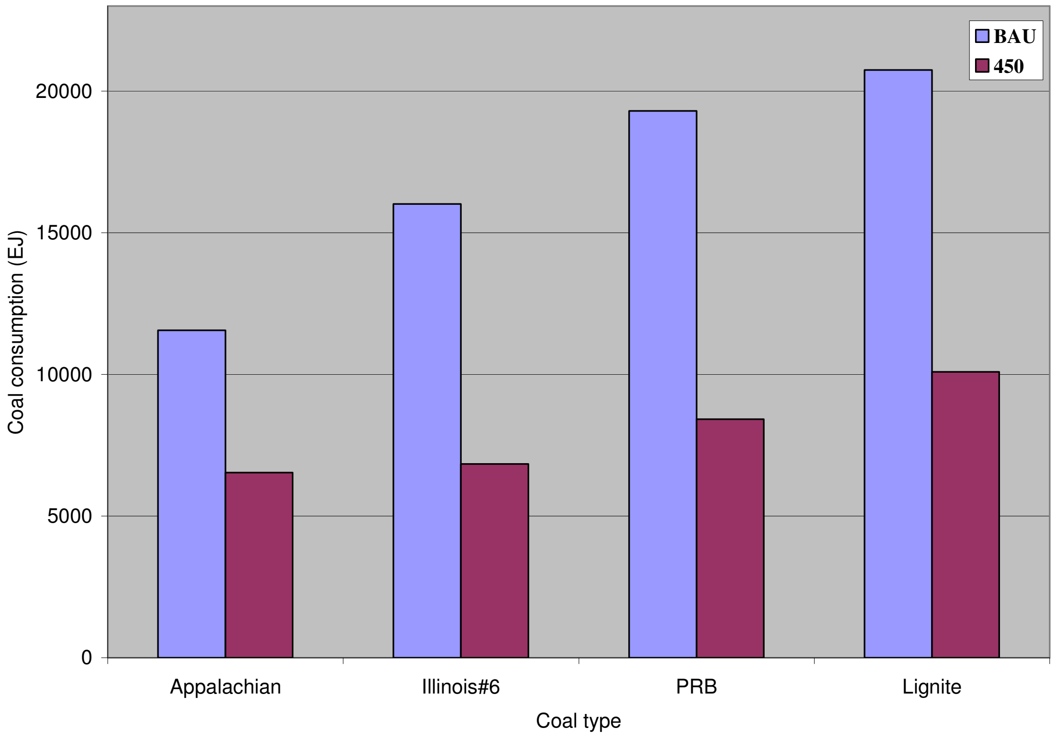

Figure 5.17: Cumulative coal consumption BAU vs. Policy scenario till 2050 (all coals)

The reduction in the coal consumption is mainly due to the constraints on CO_2 emissions. Figure 5.18 demonstrates the annual CO_2 emissions by secondary energy for various sectors in policy scenario, for Appalachian medium sulfur coal. One can find out that in the 450 ppm scenario the green line (total emissions) either overlaps with the black one (cap) just at the beginning of the timeframe and after the middle of timeframe, or it stays under the black line. The emission of the electricity sector is presented with the blue line. As obvious from figure 5.18, in the beginning of the timeframe, electricity production is the main contributor to CO_2 emissions increase. The highest emission rate of electricity sector occurs in year 2010 with 2.3 GtC/a, which is almost one third of the whole CO_2 emissions. Looking closer to the emission rate of electricity sector in figure 5.19, a decreasing trend is observed with the half of the emission rate value of 2005 in 2050 and stabilization to almost 1 GtC/a and less afterwards. It is worth mentioning that in BAU scenario, CO_2 emissions increase up to 29 GtC/a with a growing contribution of electricity sector up to 13 GtC/a.

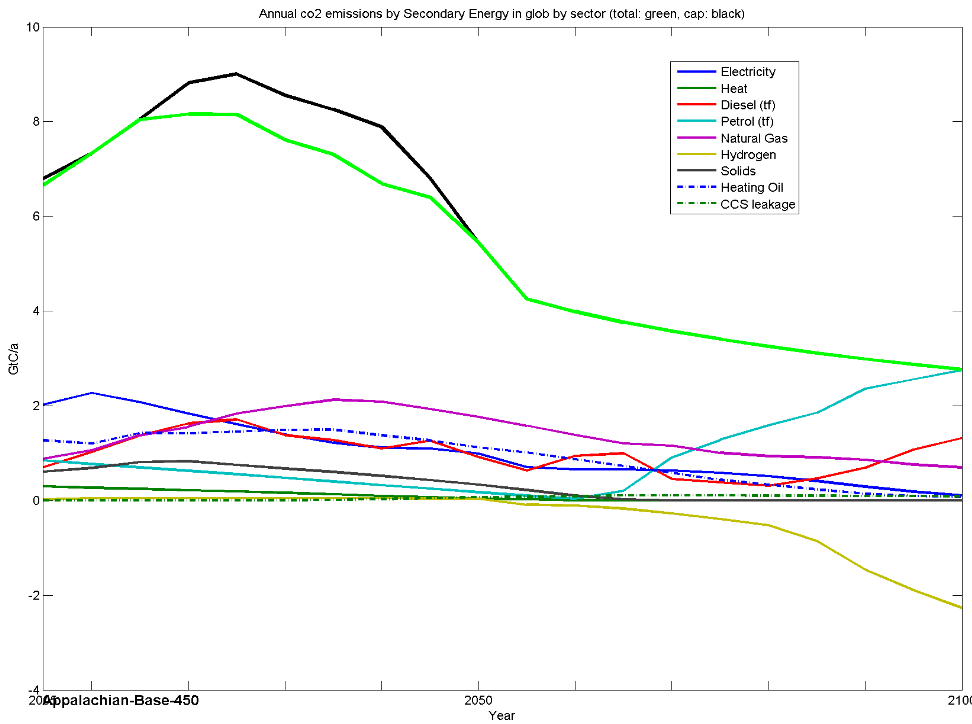

Figure 5.18: Annual CO_2 emissions by secondary energy in glob by sector, 450 ppm policy scenario, Appalachian medium sulfur coal

As clear from figure 5.19, PC and NGCC are the main CO_2 emitters in the beginning of the time frame, which is replaced by IGCC in the mid- to long-term periods.

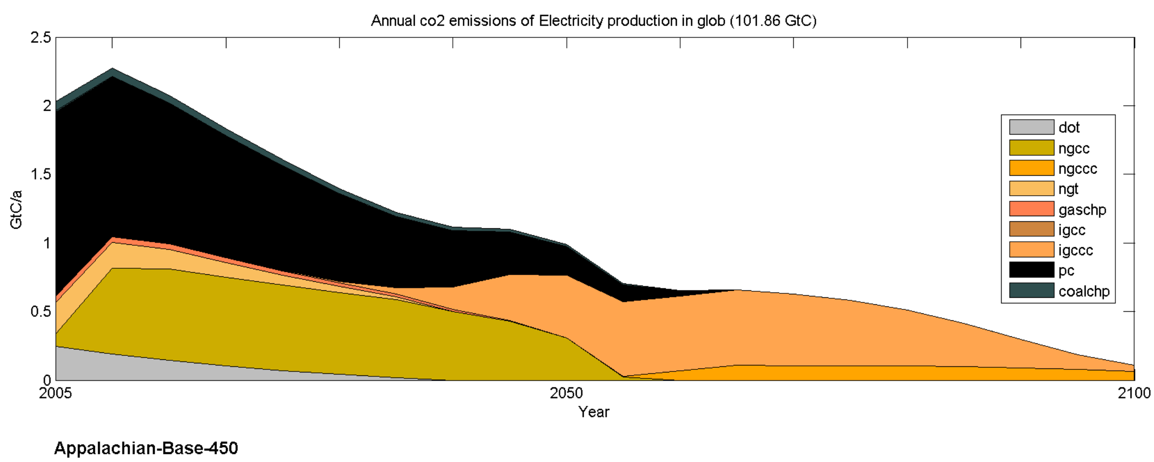

Figure 5.19: Annual CO_2 emissions of electricity production in the glob, 450 ppm policy scenario, Appalachian medium sulfur coal

The role of CCS in capturing the CO_2 and thus decreasing the annual CO_2 emissions from electricity sector is demonstrated in figure 5.20 for Appalachian medium sulfur. This figure shows the annual captured CO_2 in electricity sector which is mostly occurred via pre-combustion IGCC and to lower content via post-combustion NGCC.

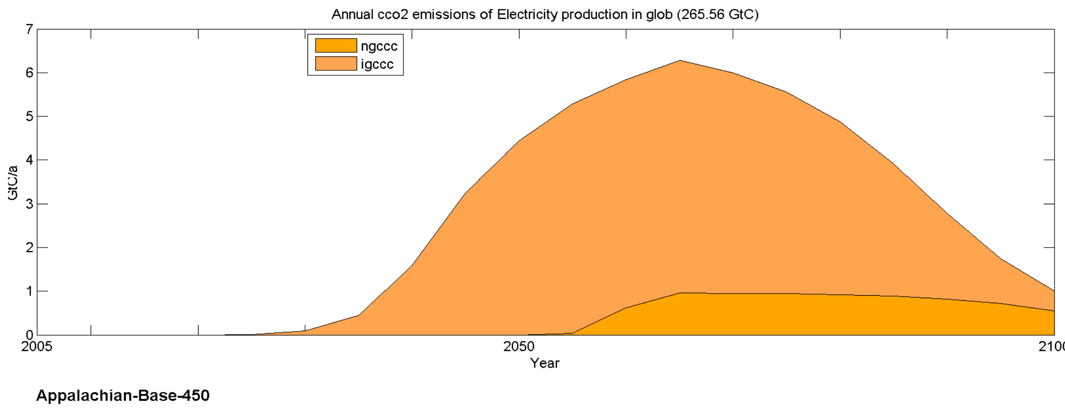

Figure 5.20: Annual captured CO_2 of electricity production in glob, 450 ppm policy scenario, Appalachian medium sulfur coal

For the rest of the coals, no trace of CCS in coal-based power plants is observed and the preference is with NGCC capture technology. Biomass based Fischer Tropsch with CCS is the other capture technology which is favored by the model among the CCS options. Considering CO_2 emissions for low rank coals, although the emissions never exceed the cap, they will not lie below the constraint at anytime. The main reasons, as comprehensive from figure 5.21, are enlarged CO_2 emissions due to more natural gas and diesel production with coal feed.

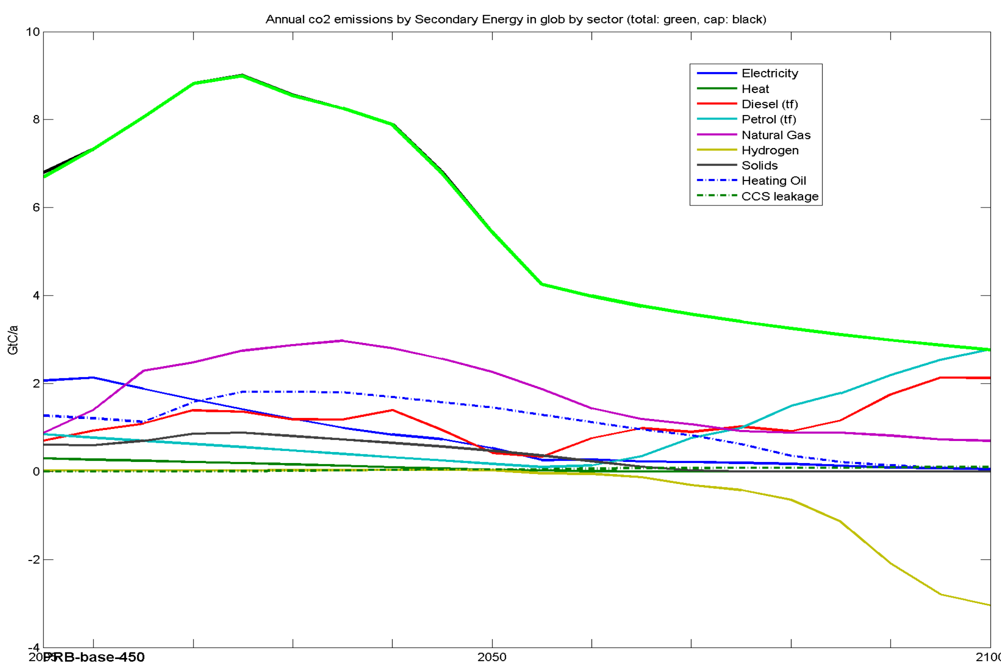

Figure 5.21: Annual CO_2 emissions by secondary energy in glob by sector, 450 ppm policy scenario, PRB coal

5.3.2. Sensitivity study

As apparent from the base case studies, several technologies will never appear in the base case model results which can be appointed to high costs, low efficiency or high emissions due to coal type. In response to the question when these technologies would be of interest, sensitivity study is a useful analytic method. In each of the sensitivity studies undertaken below, two factors are varied simultaneously in a range of values. The range of the values of these factors is to discover in a table below each experiment with a bold values representing the base case study results. To choose the range of values, the uncertainty analysis of section 4.5 is helpful since the parameters which prove to have a pronounced effect on the results of engineering modeling and the obtained distribution functions are to find there.
To perceive the effect of varying the parameters together, SimEnv modeling tool (Multi-Run Simulation Environment) has been used. SimEnv focuses on evaluation and usage of models with large and multi-dimensional output for quality assurance and scenario analysis using sampling techniques (please refer to reference [34]). SimEnv checks each possible combination between the factors, and delivers almost 400 model runs. The results are plotted in 3 dimensional graphs. The X and Y axes of the graphs present the corresponding values of the factors under analysis, whereas Z axis shows the cumulative[41] value of the result parameter in percentage. The red ball in the plots stands for the base case model result. Consequently, the plots give back information about result parameter with regard to the combination between the two sensitivity analysis factors.
The experiments have been chiefly carried out for Appalachian medium sulfur in this thesis, except from the case studies, which specifically investigate coal type influences on the model outcome. Among the possible cases which could be studied, the following experiments have been chosen.

5.3.2.1. Investment costs of PC vs. reducible investment costs of IGCC due to learning

As mentioned in the BAU scenario case study for Appalachian medium sulfur coal in sub-section 5.3.1.1, the model was very sensitive regarding the choice of coal power plants, which is mainly due to the learning effect of IGCC plants. As understandable from the base experiment with this coal, the model prefers IGCC to PC, as IGCC is considered as learning technology and improvements are foreseeable in this technology which lead to reduction in the investment costs of IGCC, but if the decline in investment doesn't reach a considerable amount, the model switches to PC, which is not a learning technology. Therefore a sensitivity analysis has been carried out which focuses on the effect of learning in technology choice in *REMIND*. In this regard, the investment costs of PC plants have been varied versus the reducible investment costs of IGCC plants due to the learning effect.

Factor	min	Base case value	max
Inco0 PC ($/kW)	1000	**1500**	1800
Incolearn IGCC ($/kW)	300	**500**	1000

[41] From 2005 to 2100

Figure 5.22 shows the share of PC and IGCC in electricity production in BAU scenario for this experiment. The first thing to expect is that as the investment costs of PC plants decrease while the investment costs of IGCC plants are not reduced considerably, the share of PC plants in electricity production rises correspondingly and can reach up to 60% for PC plants with 1000 $/kW investment costs. With the current value of PC investment costs in the base case study (1500 $/kW), the reducible investment costs of IGCC should decrease less than 400 $/kW to make a shift to PC plants possible.
It should be also pointed out that although the aim of this experiment is to see the effect of learning of IGCC, PC investment costs play an important role in this experiment, for example PC plants with low investment costs can still compete remarkably with IGCC plants having the maximum reducible investment costs of 1000 $/kW.

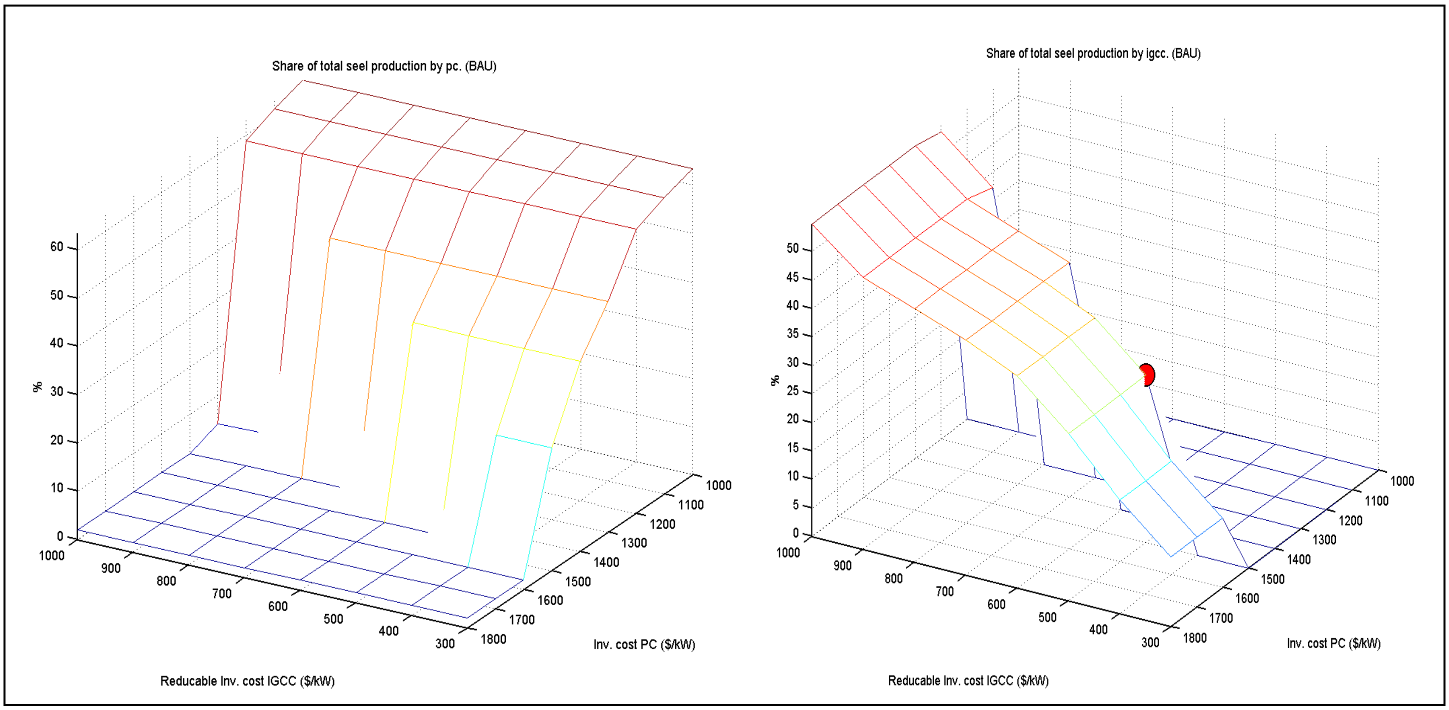

Figure 5.22: Share of electricity production by PC (left) and IGCC (right), exp.1

IGCC plants show good involvement even if only 400 $/kW is decreased from their investment costs. Share of IGCC in electricity production shows an ascending trend as the reducible investment costs increase. The share of NGCC will also change because the increase in the PC investment costs and decrease in reducible investment costs of IGCC, make the coal-fired power plants not anymore competitive with NGCC. These changes can raise the share of NGCC plants up to 12% as to see in picture 5.23

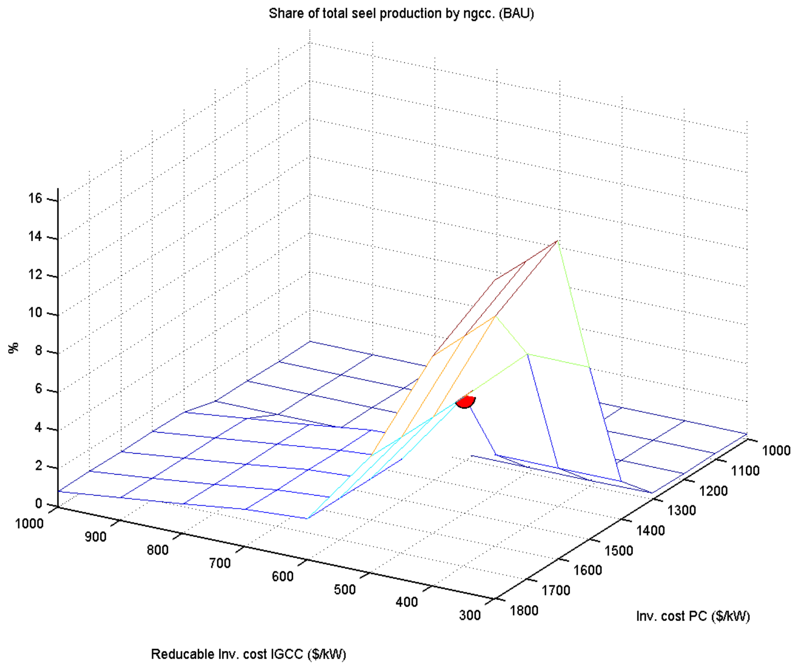

Figure 5.23: Share of electricity production by NGCC, exp.1

5.3.2.2. Investment costs of PCC vs. IGCCC

As resulted from the Policy scenario base case study in sub-section 5.3.1.2, the model tends to IGCC capture technology rather than PC capture technology when the model should meet CO_2 emission constraint. That is mainly due to the lower investment costs and higher efficiency of pre-combustion IGCC compared to post combustion PC. To see when PC post-combustion can be a technology of choice, a case study has been carried out in which the investment costs of PCC are varied vs. that of IGCCC. The factors in SimEnv with their input values are as follows

Factor	min	Base case value	max
Inco0 PCC ($/kW)	1600	**2500**	4000
Inco0 IGCCC ($/kW)	1500	**2300**	3400

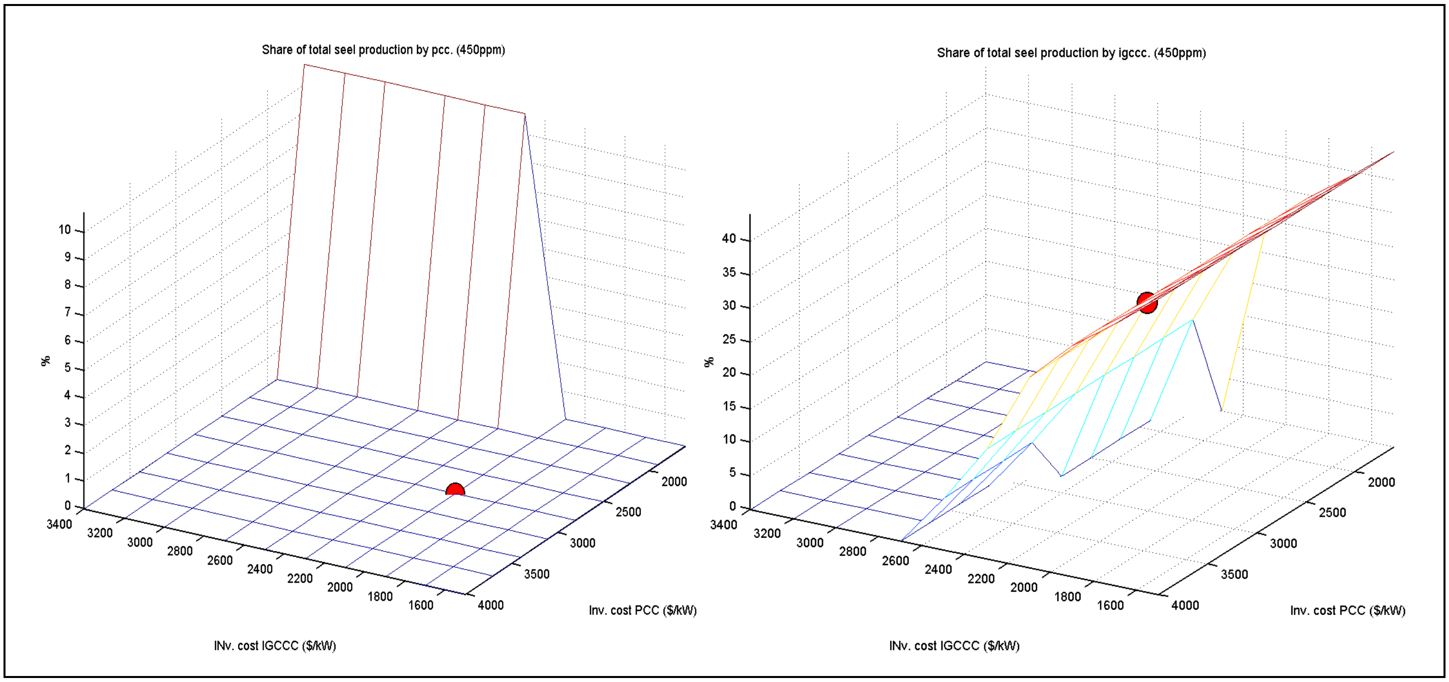

Figure 5.24: Share of electricity production by PCC (left) and IGCCC (right), exp.2

Taking into account figure 5.24, with parameter variation chosen here, PC post combustion would be a technology of choice for electricity production, only when its investment costs are reduced less than 1800 $/kW, whilst the share of IGCC pre-combustion technology can increase up to 40% with decreasing investment costs. The change in the share of other technologies is also worth considering; the share of NGCC capture and renewables esp. solar photovoltaic (spv) is reduced substantially (figure 5.25). Despite the increasing coal consumption and the decreasing consumption of cleaner fuels, the emissions will remain almost constant.

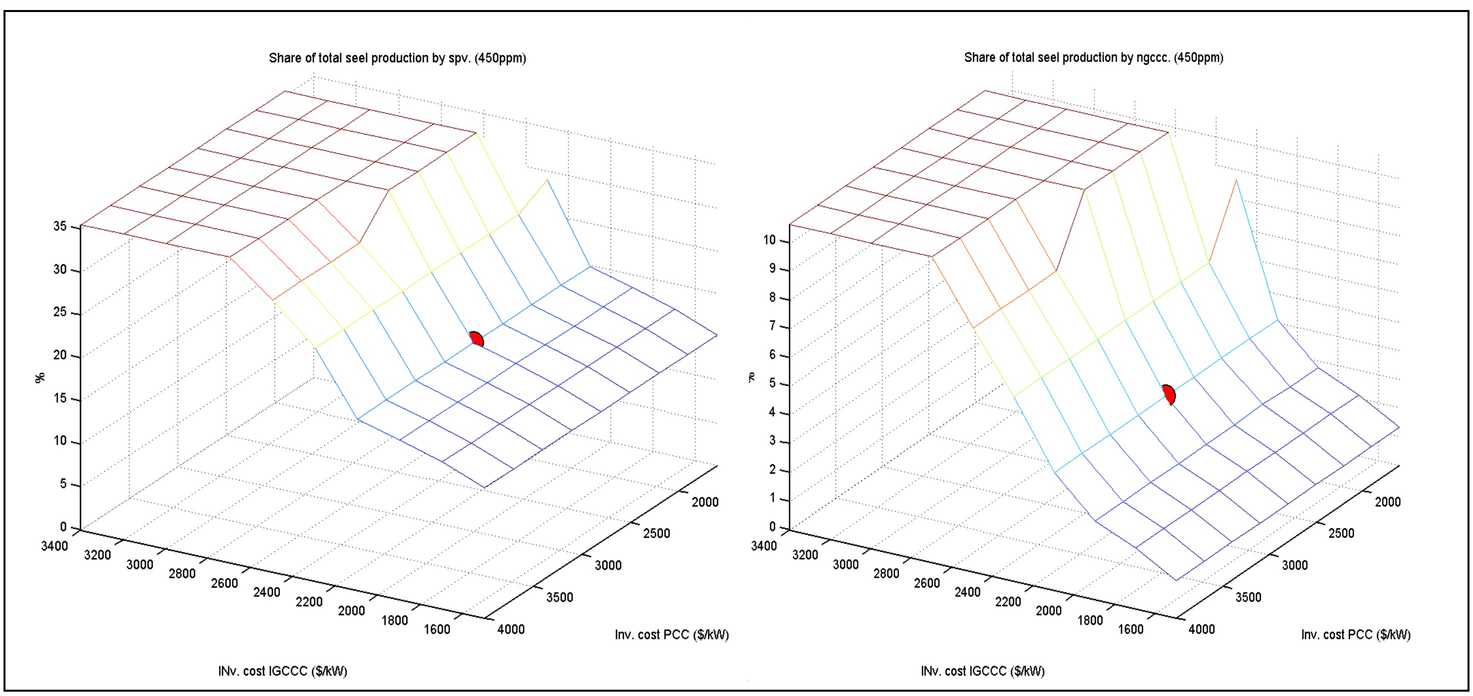

Figure 5.25: Share of electricity production by SPV (left) and NGCCC (right), exp.2

5.3.2.3. Investment costs of PCC vs. PCO

The other attention-grabbing issue is how PC capture technologies, namely post-combustion and oxyfuel compete. In other words, when is investing in these technologies reasonable, and to what extent. Thus this sensitivity study considers the variation of the investment costs of both cases.

Factor	min	Base case value	max
Inco0 PCC ($/kW)	1600	**2500**	4000
Inco0 PCO ($/kW)	1400	**3000**	4600

The interesting results of the model are first of all the share of PCC and PCO in electricity production in 450 ppm scenario.

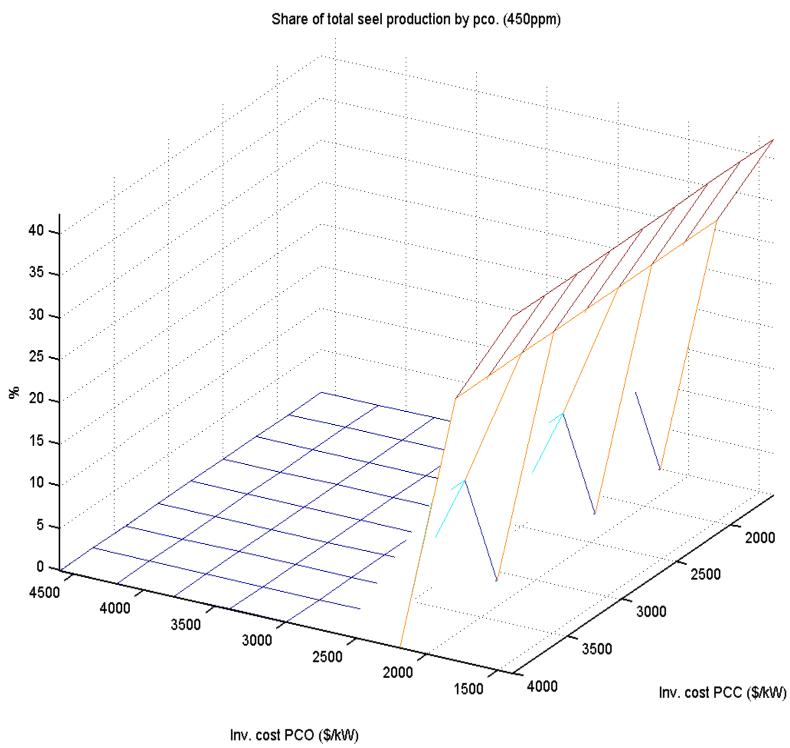

Figure 5.26: Share of electricity production by PCO, exp.3

Interestingly, the result obtained in experiment 2 for PC post-combustion holds also in this experiment, meaning that PCC is an appealing option with reduced investment costs less than1800 $/kW which corresponds to 28% reduction relative to the base case investment costs. Even with this huge cost reduction, it can respond to only 10% of the whole electricity production (considering the range chosen here). Taking into account figure 5.26, PC oxyfuel has a much higher potential in providing the world with electricity, starting with almost 2200$/kW. The economy of scale, which is a key investment costs reduction factor in PCO plants, could lead up to 40% electricity production from oxyfuel. The interactions of varying costs of PC capture plants with other fossil fuel-based capture plants are presented in figure 5.27.

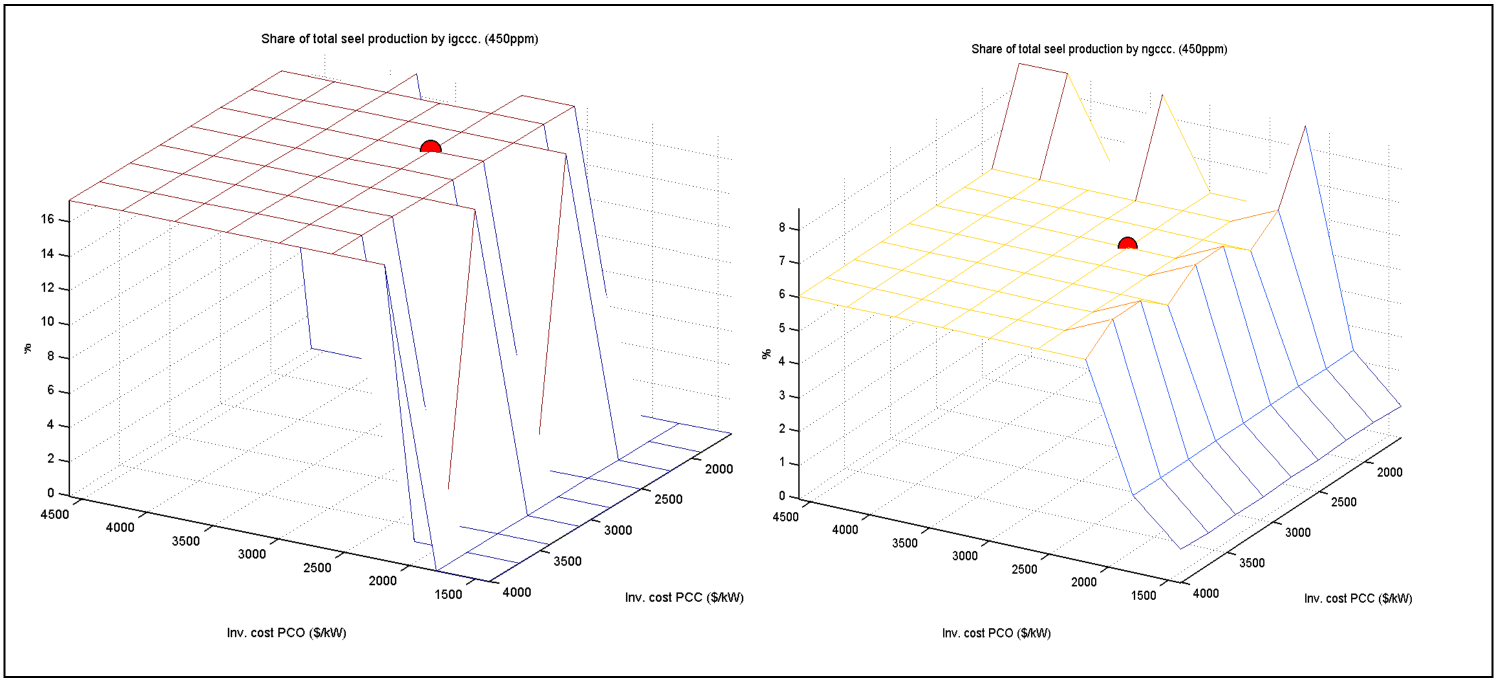

Figure 5.27: Share of electricity production by IGCCC (left) and NGCCC (right), exp.3

As evident from figure 5.27, IGCC pre-combustion will not be anymore competitive with PC capture plants if the investment costs of PC plants reduce significantly. This fact is more emphasized for oxyfuel than for PC post-combustion. By reduction of the investment costs of PC oxyfuel to almost 1700 $/kW, no trace of IGCC capture would be observable anymore. Moreover, the share of NGCC capture in electricity production is reduced but less significantly. Due to these changes, the consumption of the primary energies will also change. In line with falling oxyfuel investment costs, more coal and less gas will be used worldwide. Figure 5.28 illustrates these trends.

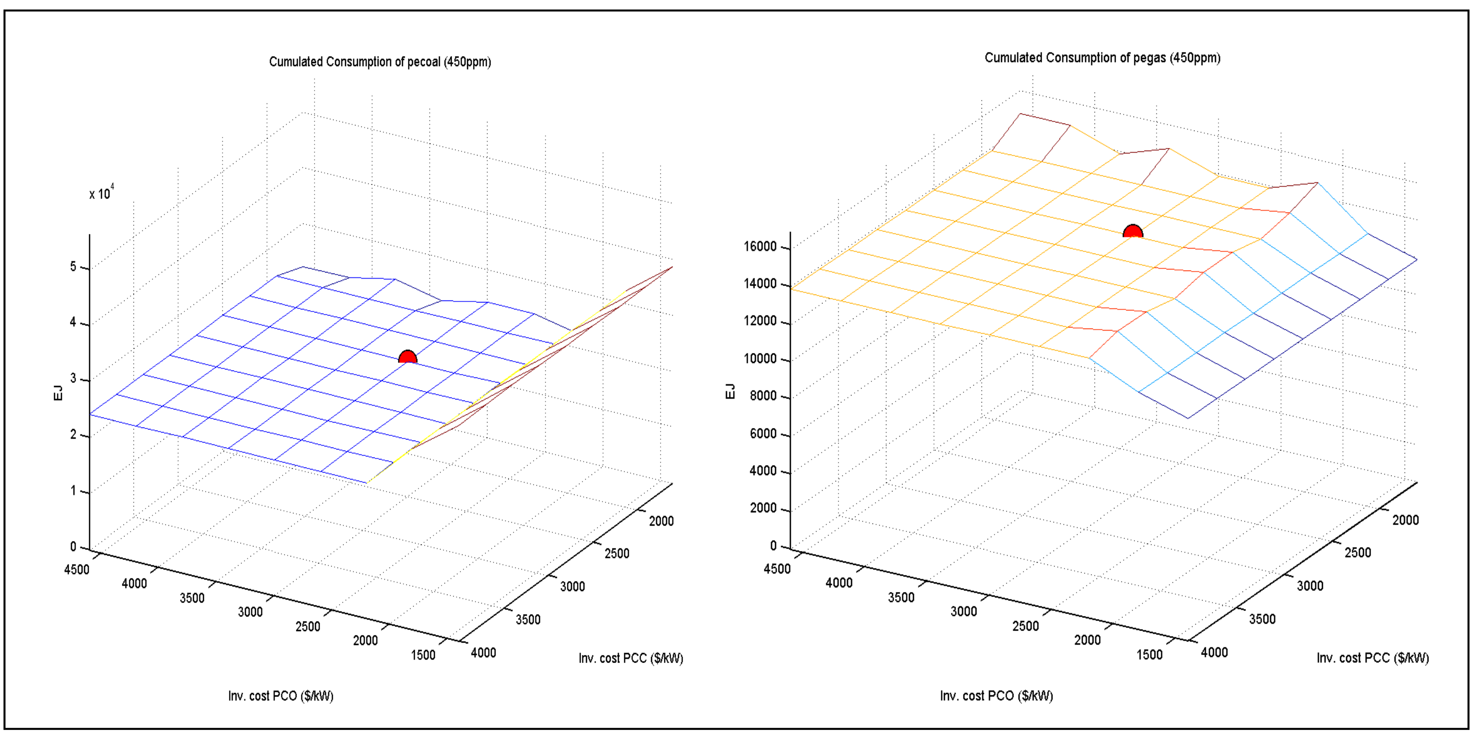

Figure 5.28: Cumulated consumption of coal (left) and natural gas (right), exp.3

5.3.2.4. Investment costs of PCO vs. IGCCC for different coal types

The results of the latter sensitivity studies reveal the fact that PC oxyfuel and IGCC capture could be promising technologies for electricity production even if the power plants have to meet CO_2 constraints, hence making coal a valuable primary energy source in policy scenario even though the CO_2 emission associated with coal is relatively higher than other primary energy sources such as natural gas or renewables. For sure this proposal is highly connected with cost reduction of these two coal capture technologies via economy of scale, learning effect and technology improvement. This criterion makes the basis of the forth sensitivity study, which is undertaken by changing the investment costs of both PCO and IGCCC. Taking into account that the coal type has a significant effect in this regard, this sensitivity study has been carried out for various coal qualities. By setting the coal type in the model, there are some facts to consider in choosing the range of the factors in the experiment regarding the characteristics of the technology and the coal itself. For PC oxyfuel, the economy of scale and the technological learning are the key factors in the reduction of the investment costs. Once being commercialized, rapid decline in the investment costs is to expect regardless of the coal type. The high reduction of PCO investment costs considered in this experiment is also due to cost savings associated with the technology improvement such as omitting FGD. For IGCC capture plant, increasing the plant size, as seen in sub-section 4.5.2, has also a considerable effect, but not as momentous as for PCO. On the other hand, coal type has a great effect in the costs of IGCC capture plants in terms of choice of suitable gasifier type and other associated parameters, such as turbine inlet temperature.

- **Appalachian medium sulfur:**

When Appalachian medium sulfur is set as the coal in the model, the following values of investment costs have been considered in SimEnv.

Factor	min	Base case value	max
Inco0 PCO ($/kW)	1000	**3000**	4200
Inco0 IGCCC ($/kW)	1500	**2300**	3400

Varying the investment costs leads to remarkable changes in the share of technologies in electricity production in 450 ppm scenario. Figure 5.29 shows the corresponding results for PCO and IGCCC. PCO doesn't take part in electricity production unless its investment costs are reduced to 2700 $/kW which can be highly expected. The share of PCO is, on the other hand, connected with the costs of IGCCC. The contribution of IGCCC in electricity production starts with 2700 $/kW investment costs and shows growing tendency. One can recognize from the right graph of picture 5.29 that IGCCC seems to be an appealing technology as its share is not strongly influenced by PCO costs.

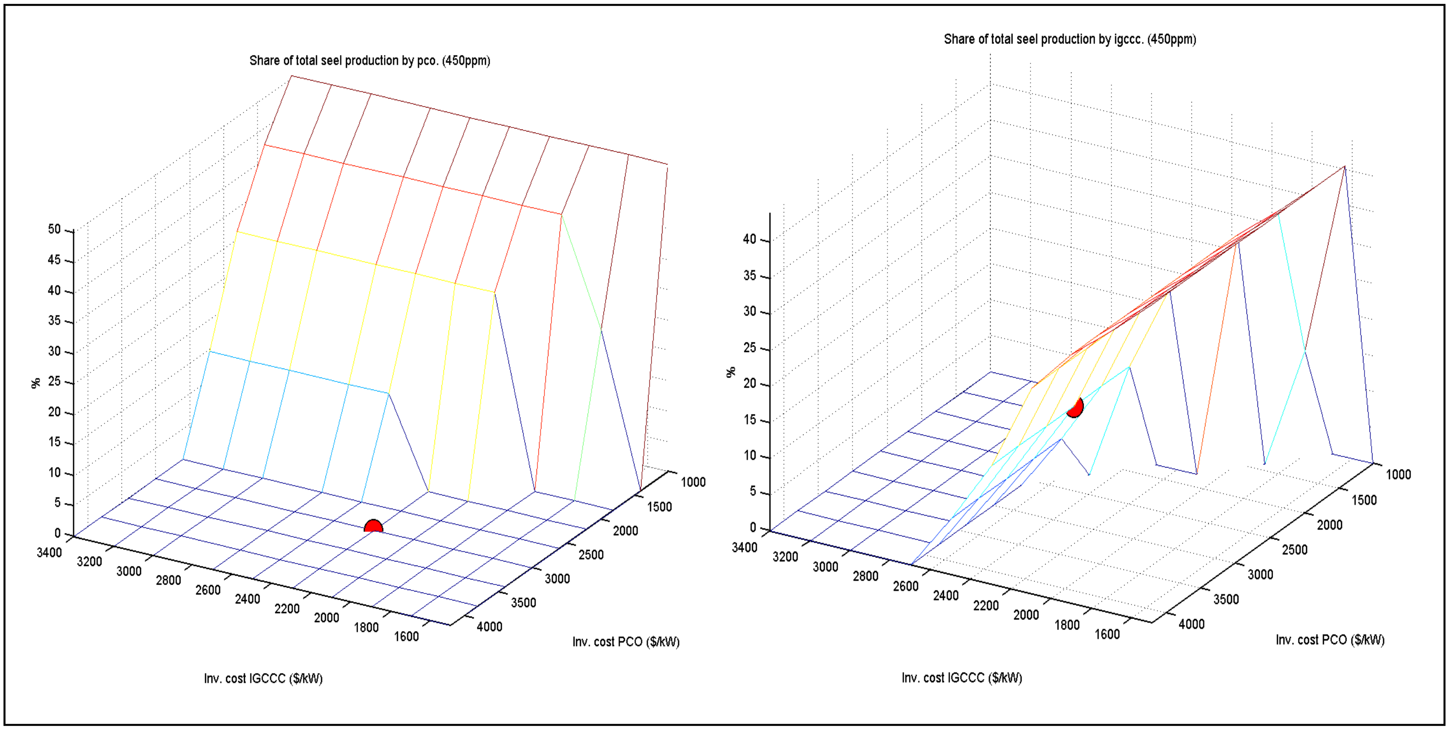

Figure 5.29: Share of electricity production by PCO (left) and IGCCC (right), exp.4 with Appalachian medium sulfur coal

The interaction with NGCC capture technology is shown in picture 5.30. As obvious from this picture, NGCCC shows a descending trend in electricity production, as it cannot compete with high reductions in PCO and IGCCC investment costs. Amazingly, the share of this technology will not exceed 11% even when the investments of the coal capture plants reach their maximum.

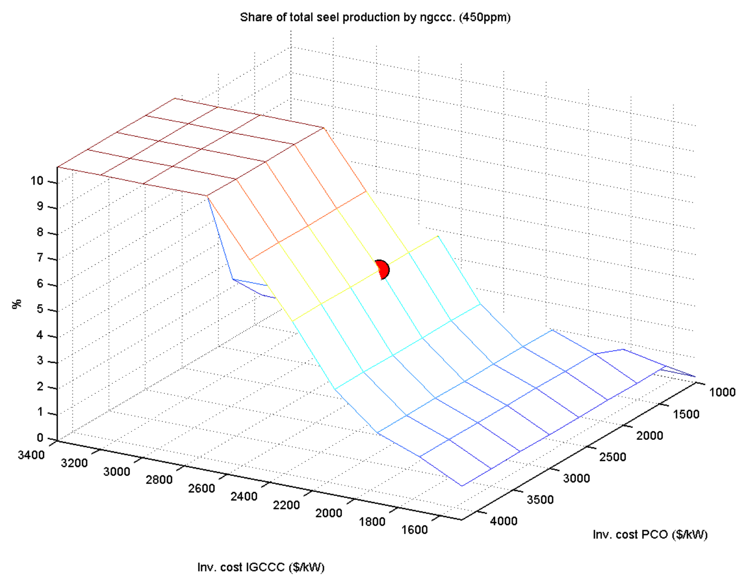

Figure 5.30: Share of electricity production by NGCCC, exp.4 with Appalachian medium sulfur coal

The change in the primary energy consumption is also a useful result. The cumulated consumption of coal and gas are shown in figure 5.31.

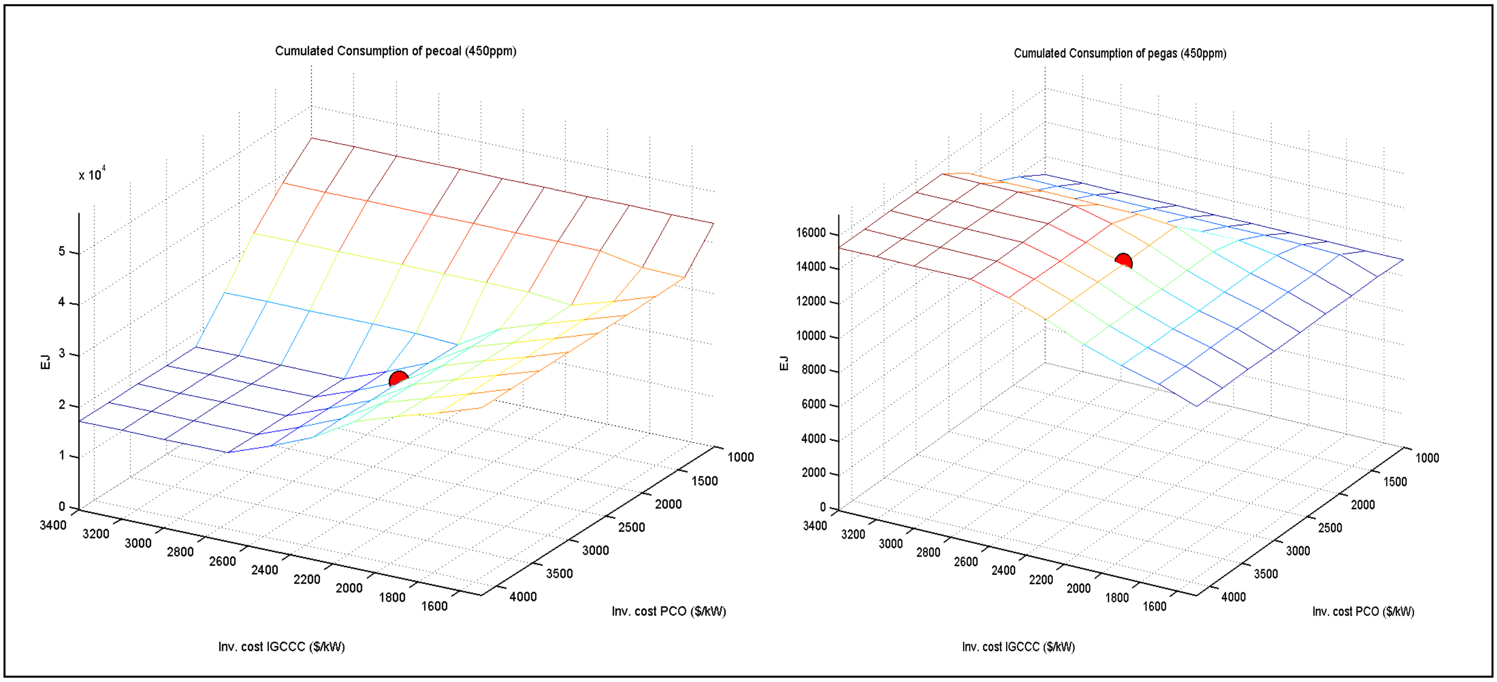

Figure 5.31: Cumulated consumption of coal (left) and gas (right), exp.4 with Appalachian medium sulfur coal

Due to this figure, the coal consumption will rise significantly while the gas consumption shows a slow reduction. Considering the right plot in this figure, despite no considerable NGCCC employment for power generation, the dependency on natural gas is not reduced to a noteworthy extent. This means that natural gas still remains an important primary energy carrier showing its role in the other sectors.

- **Illinois #6**

By choosing Illinois #6 as coal in the model, the investment costs have been varied in SimEnv as follows:

Factor	min	Base case value	max
Inco0 PCO ($/kW)	1200	**3200**	4400
Inco0 IGCCC ($/kW)	1200	**2700**	3600

The first interesting result, as also stated for Appalachian medium sulfur coal, is when and to what extent the coal fired plants with CCS would be the electricity providers. In this regard, figure 5.32 shows the contribution of PCO and IGCCC as a function of investment costs.

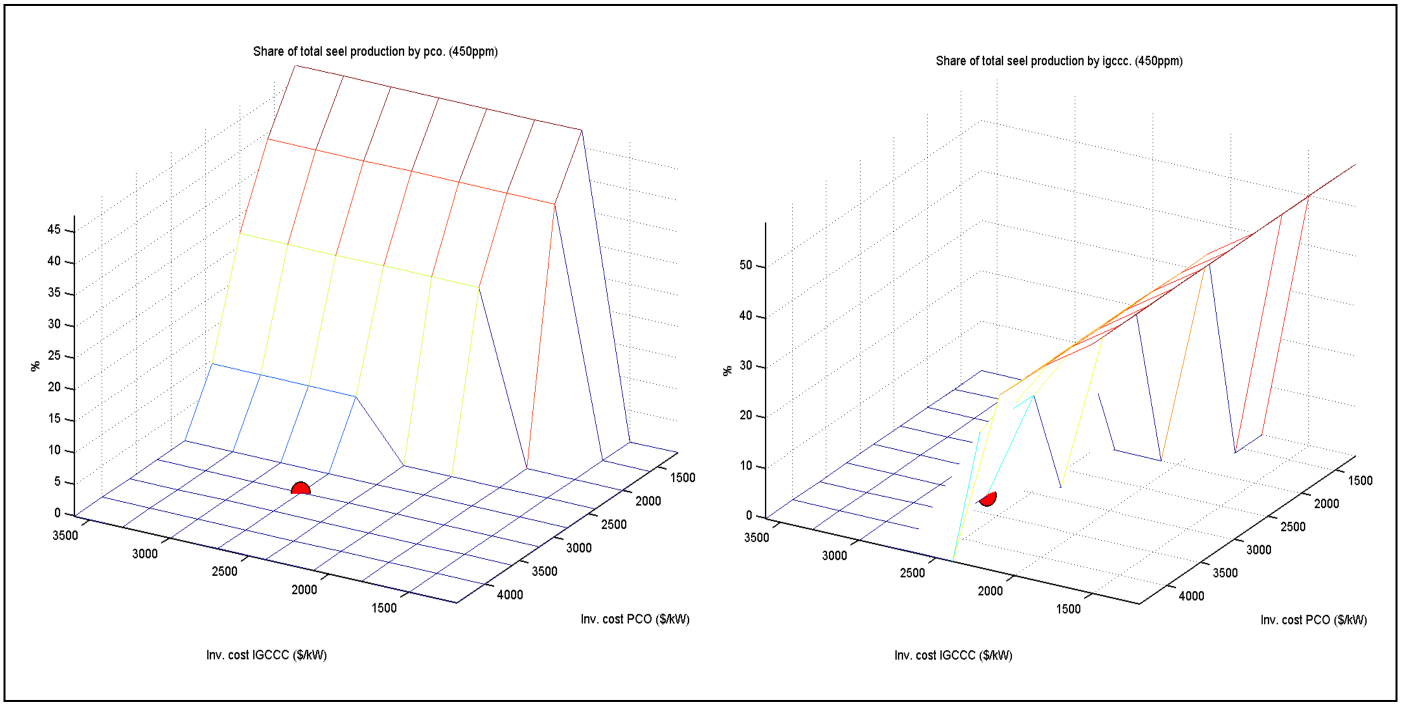

Figure 5.32: Share of electricity production by PCO (left) and IGCCC (right), exp.4 with Illinois #6

As obvious from this picture, PCO and IGCCC could have great potential in electricity production if their investment costs drop. This is even more emphasized for IGCC capture plants using this coal because as seen before in the base case study, IGCC capture was only in action when the coal was Appalachian medium sulfur noting that Illinois #6 is also a bituminous coal with high energy content. By just lowering the investment costs of IGCC capture less than 2500 $/kW, the first traces of IGCCC merges. If the investment costs reach 1500 $/kW, then the share of this technology is remarkable and can be even more than 50%. The potential of PCO seems to be promising with the starting point of 2700 $/kW. Although the maximum share is less than that of the IGCCC, it is still considerably high (45%). The side-effects of these changes are recognizable in other technologies. Figure 5.33, shows the share of NGCCC plant if this coal is to be used in the coal fired plants.

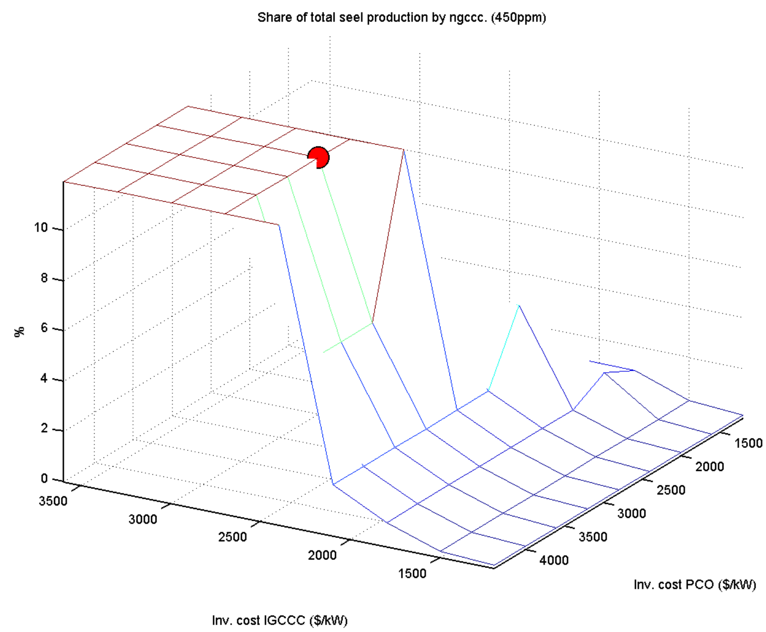

Figure 5.33: Share of electricity production by NGCCC, exp.4 with Illinois #6

As obvious from this figure, NGCCC vanishes from the electricity production technologies, if the investment costs of IGCCC is to be 1500 $/kW or lower. Regarding this figure, NGCCC electricity production breakdowns sharply when the investment costs of IGCCC falls from 2600 to 2400 $/kW. This is an important issue as NGCCC is among the favorable capture technologies chosen by the model in the base case with this coal. The coal consumption shows a higher escalation up to $6x10^4$ EJ compared to Appalachian medium sulfur.

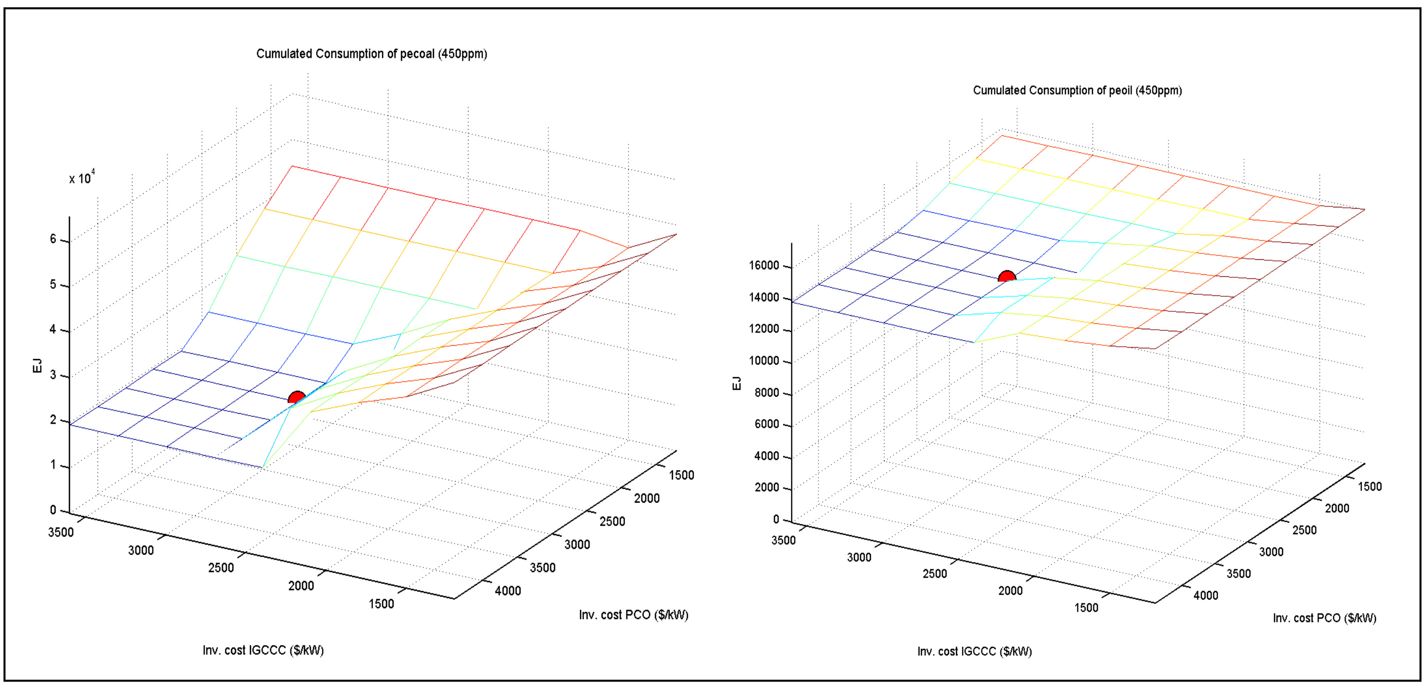

Figure 5.34: Cumulated consumption of coal (left) and oil (right), exp.4 with Illinois #6

In line with decreasing the investment costs of coal fired power plants with CCS, the usage of oil as primary energy is enlarged outstandingly. The reason is the high consumption of coal in electricity sector rather than in transport sector. Referring back to the figure 5.16, this coal was highly favored in the transport sector for diesel production via coal Fischer Tropsch. By employing more coal for electricity generation, the share of coal FT recycle for diesel production in transport sector declines significantly, resulting in substitution of more biomass FT recycle (bioftcrec) and refinery oil-to-diesel (refdip) technologies to fulfill the gap of diesel production in transport sector (figure 5.35).

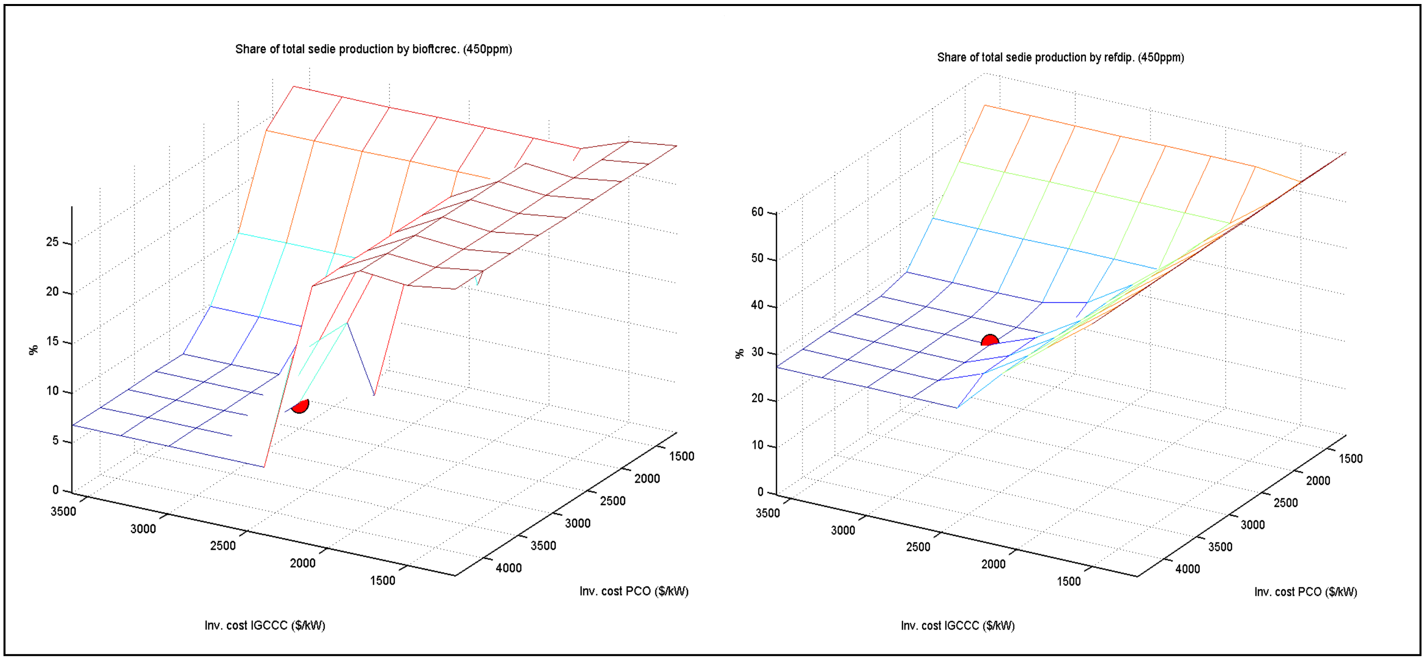

Figure 5.35: Share of electricity production by Bioftrec (left) and Refdp (right), exp.4 with Illinois #6

It is also worth mentioning that with an enormous decline in the IGCCC investment costs down to 1500 $/kW, this technology could show potential even in BAU scenario.

- **PRB**

Changing the coal to lower rank coals such as PRB or lignite produces more or less the same results as in the case of Illinois #6. Because the result of the electricity production in 450 ppm scenario was almost the same for PRB and lignite, the sensitivity study would result in the same outcome for both coals, thus just the case of PRB is presented here. For this coal, another range for IGCCC investment costs have been considered as the costs of IGCCC plants with this coal is considerably more than bituminous coals. Cost reduction is foreseeable by using dry-feed gasifier and/or technology improvement.

Factor	min	Base case value	max
Inco0 PCO ($/kW)	1200	**3200**	4400
Inco0 IGCCC ($/kW)	1200	**3000**	3600

As also stated for other coals, both PCO and IGCCC technologies prove to have good futures. Figure 5.36 shows the share of PCO in electricity production using this coal. In case of low rank coals, PCO even seems to be more competitive with IGCCC, meaning that the investment costs of IGCCC should fall below 2400 $/kW to make it capable to compete with PCO. By reaching 2600 $/kW and lower investment costs, IGCCC shows a rapid improvement in placing itself as a major electricity producer.

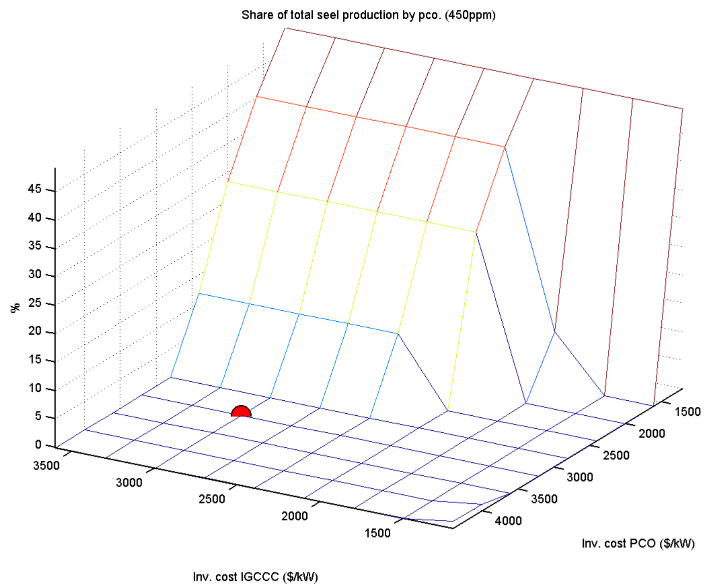

Figure 5.36: Share of electricity production by PCO, exp.4 with PRB coal

An intense decline in the share of other competing electricity generating technologies, such as NGCCC, nuclear and solar, is to except. This reduction is recognizable for NGCCC and light water reactor (nuclear) in figure 5.37. According to these graphs, just a slight improvement in IGCCC with low rank coals, which is highly expected, is required to reduce the investment costs of this technology lower than 2700 $/kW and consequently diminishes the role of other mitigation technologies such as NGCCC and nuclear. Investing in IGCCC with low-rank coals is accompanied with other co-benefits as well. These coals have much lower price in comparison with bituminous coals and other energy carriers such as natural gas. This would lead to lower electricity cost and less dependency of electricity production on natural gas. Moreover, IGCCC doesn't face the safety problems of nuclear energy. Additionally, it has an inherent advantage regarding other pollutants compared to other coal technologies.

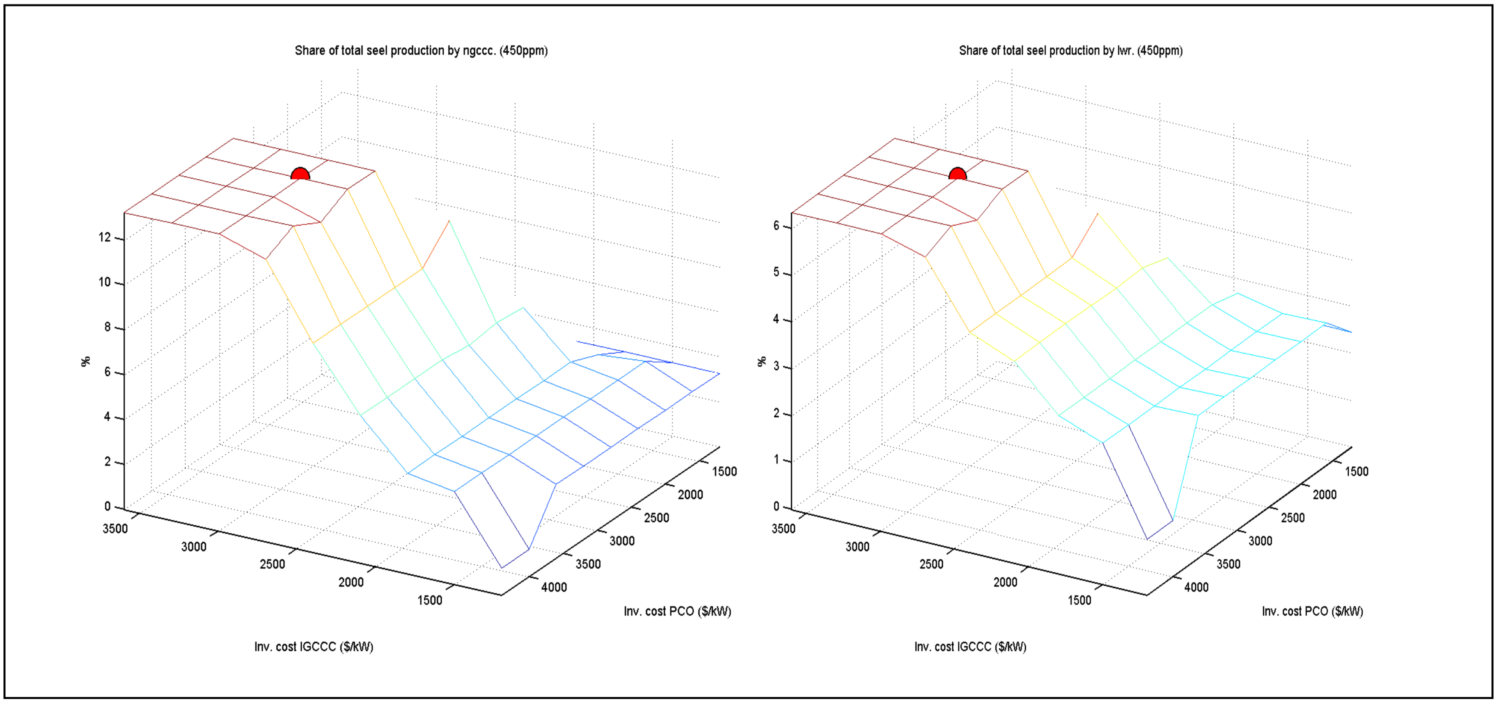

Figure 5.37: Share of electricity production by NGCCC (left) and LWR (right), exp.4 with PRB coal

Chapter 6: Conclusions and recommendations

6.1. Conclusions

Referring back to the thesis main questions, here the main findings of the thesis are highlighted:

- The thesis affirms the other studies concerning CCS in the fact that CCS is a promising technology to achieve high CO_2 emissions reduction from fossil fuel-based power plants; however it is energy-intensive and expensive.

- The variability of coal type is a pre-dominant factor for coal power plants and thus for the whole energy system. PC generation without CO_2 capture is slightly favored over IGCC with GE gasifier regarding the investment costs and efficiency for high heating value, bituminous coals, but this gap increases as coal heating value decreases. For CO_2 capture plants, for high-heating value bituminous coals IGCC is being favored; but as coal heating value decreases, IGCC capture plant is either comparable in cost and efficiency (for sub-bituminous coal e.g. PRB) or higher in cost and much lower in efficiency (for lignite coal) than a PC plant with capture.

- Technological development and economy of scale may lead to significant cost reduction of CCS technologies in the future. This finding is especially emphasized for IGCC plants and PC oxyfuel. Higher efficiencies are foreseeable with improving gasification technology for low rank coals. With reduction in the investment costs of PC oxyfuel, which can be accomplished by plant size increase and technological learning, the contribution of this technology in providing the world with electricity would be remarkable in a carbon constrained world.

- Air pollutant regulations can, when applied, affect the cost and performance of the plants, but no significant differences in the model results are to recognize between European emission limit value for large combustion plants and NSPS (New Source Performance Standards) from US.

- IGCC has inherent advantages with respect to emissions of multi-pollutants e.g. SO_2, NO_X and PM (Particulate Matter) to PC plants. NGCC eliminates the need of severe emission control systems.

- Switching to gas as a cleaner and more effective fuel is, on the whole, a good mitigation solution, but is also in conjunction with factors such as natural gas price. Higher gas prices can lead to lower capacity factor and thus higher COE (Cost of Electricity).

- The fossil fuel based power plants are subject to uncertainty in performance parameters such as plant capacity factor, scale parameters such as plant size, and technical parameters such as turbine inlet temperature. The uncertain parameters may lead to different plant performance, costs and emissions.

- In a wider context of an energy system model, where all technologies including the ones leading to CO_2 reduction take part, under BAU scenario the model tends to NGCC among the fossil fuel power plants regardless of the coal type but the extent of NGCC contribution is influenced by coal type. Among the coal power plants, IGCC is favored in the model when using high quality bituminous coals such as Appalachian medium sulfur, whereas for lower coal qualities the model favors PC.

- CCS technologies are less appealing for electricity production under BAU scenario. Under a carbon constrained scenario that achieves a CO_2 stabilization of 450 ppm, CCS is an attractive option for IGCC with bituminous coal whereas for lower rank coals NGCC capture technology prevails over coal capture technologies. PC capture technologies could have a potential in electricity production if their investment costs are reduced. Sensitivity studies in this regard show that the contribution of PC with post-combustion capture starts with the investment costs less than 1800 $/kW, whereas PC oxyfuel has a better potential and shows its contribution with investment costs of 2700 $/kW and less.

- Although coal conversion technology seems to be a premature route to generate electricity in both BAU and policy scenarios, the choice between IGCC and PC is highly dependant on coal type and factors such as learning effect which could reverse the model results. The coal type, will not only change the contribution of coal power plants, but also it will alter the results of the whole energy system regarding the electricity mix and primary energy mix.

- The competition among the technologies and thus energy sectors for consumption of primary energies plays an important role in allocating coal and natural gas in electricity sector and thus the amount of electricity produced. Bituminous coal despite lower usage could produce more electricity.

- In line with costs reduction of CCS technologies, contribution of other mitigation options in electricity sector, such as renewables and nuclear, declines considerably. This fact will, in return, change the distribution of primary energy sources among various sectors.

6.2. Recommendations

This thesis can be used for engineering purposes, politic consulting and further model development, e.g. of *REMIND,* in the future. It should be noted, however, that the results of the thesis are based on the structure, parameters and assumptions of the references and models it used, and as these sources can be accompanied with

simplifications and shortcomings, the results, in return, are subject to uncertainty.
For instance, dry-feed gasification, which is the suitable technology for electricity production of low rank coals, has not been available in IECM model at the time of this thesis. As all the results are only true for GE (Texaco) gasifier, the conclusions concerning the IGCC plants are of restricted values. Thus for future wok, it is recommendable to investigate the effect of using other gasification technologies such as Shell dry feed gasifier.
NGCC oxyfuel is also not included in both models (IECM and *REMIND*).
Although this technology is in the development stage, it seems to have a good potential and its detailed evaluation can be suggested.
Other coal consuming technologies in *REMIND* are not parameterized for each coal type individually as this thesis has done for coal power plants. In order to provide consistency in the results, in this thesis a relative escalation for these technologies has been carried out. In this regard, more consistent considerations in these technologies and the same methodology applied for the coal power plants can be recommended.
At the time of this thesis, different coal types are not available at the same time in *REMIND* model, and therefore the model runs are carried out with a single coal type in each experiment. It will be interesting to know how the model behaves in choosing particular coal type for individual technologies when all coal types take part in the model simultaneously.
Improving the other components of the CCS chain in *REMIND* and integrating the industrial usage of CCS in the model are other issues for improving the exactness of the results in the future.

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Appendix A

Case study comparing PC plants without and with post-combustion capture with NSPS constraints and EU constraints

The emissions from the plants, the capital costs and the revenue required are listed for both constraints:

Power plant total particulate emission to the air (tonne/hr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC (US)	0.05417	0.0549	0.05666	0.0585
PC (EU)	0.07222	0.0732	0.07555	0.07801
PCC (US)	0.02708	0.02745	0.02833	0.02926
PCC (EU)	0.03611	0.0366	0.03778	0.03901

Power plant total CO2 out (kg-mole/hr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC (US)	8441	8704	9090	9521
PC (EU)	8450	8714	9090	9535
PCC (US)	845.5	871.8	910.8	953.9
PCC (EU)	845.5	871.8	910.8	953.9

Power plant total SO2 out (kg-mole/hr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC (US)	16.82	17.05	22.73	18.18
PC (EU)	9.113	9.235	22.73	9.852
PCC (US)	0.0087	0.01637	0.002273	0.008732
PCC (EU)	0.0087	0.01637	0.002273	0.008736

Power plant total NO out (kg-mole/hr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC (US)	4.488	4.608	4.867	7.906
PC (EU)	4.488	4.608	4.867	4.899
PCC (US)	4.488	4.608	4.867	7.906
PCC (EU)	4.488	4.608	4.867	4.899

Power plant total NO2 out (kg-mole/hr)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC (US)	0.2362	0.2426	0.2562	0.4160
PC (EU)	0.2362	0.2426	0.2562	0.2579
PCC (US)	0.1771	0.1820	0.1921	0.3120
PCC(EU)	0.1771	0.1820	0.1921	0.1935

Capital required ($/kW-net)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC (US)	1503	1561	1438	1695
PC (EU)	1500	1569	1441	1688
PCC (US)	2544	2680	2744	2987
PCC (EU)	2539	2675	2737	2977

Revenue Required ($/MWh)

	Appalachian medium sulfur	Illinois # 6	Wyoming powder river basin	North Dakota lignite
PC (US)	55.62	58.47	52.71	62.69
PC (EU)	55.62	58.85	53.00	63.48
PCC (US)	103.9	112.6	109.3	121.9
PCC (EU)	103.8	112.5	109.1	122.8

Appendix B

List of abbreviation in *REMIND*

te	*energy technologies:*
ngcc	natural gas combined cycle
ngccc	natural gas combined cycle with capture
ngt	natural gas turbine
gastr	transformation of gases
gaschp	CHP using gas
gashp	HP using gas
gash2	gas to hydrogen
gash2c	gas to hydrogen with capture
refped	refinery oil to petrol with diesel oc
refpeh	refinery oil to petrol with heating oil oc
refdip	refinery oil to diesel with petrol oc
refhop	refinery oil to heating oil with petrol oc
dot	diesel oil turbine
dhp	diesel oil HP
igcc	integrated coal gasification cc
igccc	integrated coal gasification cc with capture
pc	pulverised coal power plant
pcc	pulverised coal power plant with capture
pco	pulverised coal power plant with oxyfuel capture
coalchp	chp coal
coalhp	HP coal
coaltr	transformation of coal
coalgas	coal gasification
coalftot	coal based fischer-tropsch once through
coalftrec	coal based fischer-tropsch recycle
coalftcot	coal based fischer-tropsch with capture once through
coalftcrec	coal based fischer-tropsch with capture recycle
coalh2	coal to hydrogen
coalh2c	coal to hydrogen with capture
biotr	transformation of biomass
biochp	CHP bio
biohp	HP bio
biogas	gasification of biomass
bioftot	biomass based fischer-tropsch once through
bioftrec	biomass based fischer-tropsch recycle
bioftcot	biomass based fischer-tropsch with capture once through
bioftcrec	biomass based fischer-tropsch with capture recycle
bioh2	biomass to hydrogen
bioh2c	biomass to hydrogen with capture
bioethl	biomass to ethanol

bioeths	sugar and starch biomass to ethanol
biodiesel	oil biomass to biodiesel
nuc	nuclear conventional
geohdr	geothermal electric hot dry rock
geohe	geothermal heat
hydro	hydro electric
wind	wind power converters
winof	wind power converters - offshore
spv	solar photovoltaic
sth	solar thermal electricity generation
solhe	solar thermal heat generation
elh2	hydrogen electrolysis
tdelh	electricity t&d to households
tdeli	electricity t&d to industry
tdgah	gas t&d to households
tdgai	gas t&d to industry
tdgat	gas t&d to transport
tdho	heating oil to household t&d
tdhoi	heating oil to industry t&d
tdpp	petro product to industry t&d
tdh2h	hydrogen to households t&d
tdh2i	hydrogen to industry t&d
tdh2t	hydrogen to transportation t&d
tddie	diesel t&d
tdpet	petrol t&d
tdso	solids t&d to households
tdsoi	solids t&d to industry
tdhe	heat t&D
ccscomp	compression of co2
ccspipe	transportation of co2
ccsinje	injection of co2
ccsmoni	monitoring of co2
lwrfp	LWR fuel production
lwr	Light Water Reactor (nuclear)
lwrrep	Reprocessing of LWR products
lwrdd	Direct disposal of LWR products
fbrfp	fbr fuel production
fbr	Fast Breeder Reactor (nuclear)
fbrrep	Reprocessing of fbr products
fbrdd	Direct disposal of FBR products
pu2hlw	conditioning of plutonium (for disposal as HLW)
llwis2ts	LLW transportation and terminal storage
ilwis2ts	ILW transportation and terminal storage
hlwis2ts	HLW transportation and terminal storage

Appendix C

Parameters of electricity generating technologies:

	dot	ngt	gaschp	coalchp	lwr	fbr	hydro	wind	winof	spv	sth	geohdr	biochp
inco0 ($/kW)	520	455	1040	1755	3250	5850	3000	1100	1700	4500	3500	3900	1787
mix0 (-)	0.072	0.1	0.0272	0.02	0.158	0	0.166	0.0034	0.0000136	0.001	0.00009	0.00182	0.012
eta (%)	0.3	0.38	0.45	0.4	45.21	131.51	0.45	0.35	0.45	0.12	0.16	0.17	0.433
nu (-)	0.4	0.4	0.6	0.7	0.8	0.8	1	1	1	0.85	0.88	0.9	0.46
omf (-)	0.03	0.03	0.03	0.03	0.01	0.013	0.02	0.025	0.05	0.025	0	0.04	0.035
omv ($/kWa)	10	20	35	60	65	84.5					219	0	30.11
incolearn ($/kW)	-	-	-	-	500	500		400	1020	3500	1600	-	550
ccap0 (TW)	-	-	-	-	0.5	0.01		0.066	0.00305	0.0044	0.0004	-	0.001
learn (-)	-	-	-	-	0.05	0.05		0.1	0.12	0.2	0.2	-	0.08

Parameters of technologies with electricity as couple product:

	coalh2	coalh2c	coalftot	coalftcot	bioftot	bioftrec	bioftcot	bioftcrec	bioethl
inco0 ($/kW)	1208	1367	1313	1365	3400	2500	3876	3000	2383.43
mix0 (-)	0.3	0	0	0	0	0	0	0	0
eta (%)	0.59	0.57	0.25	0.25	0.24	0.4	0.25	0.41	0.363
nu (-)	0.85	0.85	0.85	0.85	0.91	0.91	0.91	0.91	0.904
omf (-)	0.03	0.03	0.05	0.055	0.04	0.04	0.04	0.04	0.065
omv ($/kWa)	34.3	39.4	4.12	4.2	10.6			10.6	97.265
incolearn ($/kW)	-	-	-	-	510	375	580	450	1191.715
ccap0 (TW)	-	-	-	-	0.01	0.01	0.01	0.01	0.001
learn (-)	-	-	-	-	0.15	0.15	0.15	0.15	0.2

Parameters of coal consuming technologies (other than the ones listed above):

	coalgas	coaltr	coalhp	coalftrec	coalftcrec
inco0 ($/kW)	780	130	520	1300	1352
mix0 (-)	0.05	0.35	0.312	0	0
eta (%)	0.6	0.95	0.7	0.4	0.4
nu (-)	0.9	0.9	0.4	0.85	0.85
omf (-)	0.03	0.03	0.03	0.05	0.055
omv ($/kWa)				4.12	4.2
incolearn ($/kW)	-	-	-	-	-
ccap0 (TW)	-	-	-	-	-
learn (-)	-	-	-	-	-

Eidesstattliche Erklärung

Die selbständige und eigenhändige Anfertigung
versichere ich an Eides statt.

27.05.2008

Datum   Unterschrift, Yasaman Mirfendereski