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Economic Competitiveness of Underground Coal Gasification Combined with Carbon Capture and Storage in the Bulgarian Energy Network

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“Economic Competitiveness of Underground Coal Gasification Combined with Carbon Capture and Storage in the Bulgarian Energy Network”

Von der Fakultät Georessourcen und Materialtechnik
der Rheinisch-Westfälischen Technischen Hochschule Aachen

zur Erlangung des akademischen Grades eines

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genehmigte Dissertation

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aus Aachen

Berichter: Univ.-Prof. Dr. rer. nat. Dr. h.c. (USST) Rafig Azzam
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Getting wisdom is the wisest thing you can do!

And whatever else you do, develop good judgement. (Proverbs 4:7)

Abstract

Underground coal gasification (UCG) allows for exploitation of deep-seated coal seams not economically exploitable by conventional coal mining. Aim of the present study is to examine UCG economics based on coal conversion into a synthesis gas to fuel a combined cycle gas turbine power plant (CCGT) with CO_2 capture and storage (CCS). Thereto, a techno-economic model is developed for UCG-CCGT-CCS costs of electricity (COE) determination which, considering site-specific data of a selected target area in Bulgaria, sum up to 72 €/MWh in total. To quantify the impact of model constraints on COE, sensitivity analyses are undertaken revealing that varying geological model constraints impact COE with 0.4 % to 4 %, chemical with 13 %, technical with 8 % to 17 % and market-dependent with 2 % to 25 %. Besides site-specific boundary conditions, UCG-CCGT-CCS economics depend on resources availability and infrastructural characteristics of the overall energy system. Assessing a model based implementation of UCG-CCGT-CCS and CCS power plants into the Bulgarian energy network revealed that both technologies provide essential and economically competitive options to achieve the EU environmental targets and a complete substitution of gas imports by UCG synthesis gas production.

Kurzfassung

Untertagevergasung von Kohle (UTV) ermöglicht die Nutzung tiefliegender, durch den konventionellen Bergbau wirtschaftlich nicht erschliessbarer Kohleflöze. Im Rahmen dieser Arbeit wird die Wirtschaftlichkeit der UTV basierten Kohleumwandlung in Synthesegas und dessen Verstromung in einem Gas-und Dampfturbinen Kraftwerk (GuD) mit anschliessender CO_2-Abscheidung und -Speicherung (CCS) analysiert. Dazu wird ein techno-ökonomisches Modell zur Berechnung der Stromgestehungskosten (StGK) des UTV-GuD-CCS-Prozesses entwickelt welche, unter Berücksichtigung lokalspezifischer Daten eines Untersuchungsgebiets in Bulgarien, insgesamt 72 €/MWh betragen. Mittels Sensitivitätsanalysen wird der Einfluss standortspezifischer Rahmenbedingungen auf die StGK quantifiziert, wobei variierende geologische Randbedingungen StGK-Variationsbandbreiten von 0.4 % bis 4 %, chemische von 13 %, technische von 8 % bis 17 % und marktbedingte von 2 % bis 25 % verursachen. Neben standortspezifischen Rahmenbedingungen beeinflussen Ressourcenverfügbarkeit und die Infrastruktur eines Energiesystems die Wirtschaftlichkeit des UTV-GuD-CCS-Prozesses. Eine modellbasierte Implementierung von UTV-GuD-CCS und CCS-Kraftwerken in das bulgarische Energiesystem zeigt, dass beide Technologien essenzielle und wirtschaftliche Möglichkeiten zum Erreichen der EU-Klimaschutzziele bieten und Gasimporte vollständig durch UTV Synthesegasproduktion substituierbar sind.

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The present study was elaborated in the context of the UCG&CO_2STORAGE project (grant RFCS-CT-2010-00003) funded by the European Union (EU) and the Research Fund for Coal and Steel (RFCS). I gratefully appreciate this financial support. I also appreciate the free license for using the software tool Long Range Energy Alternatives Planning System (LEAP), provided by the COMMEND Community. Thanks to the McGraw-Hill Companies (PLATTS) providing relevant data to elaborate this thesis. Furthermore, I thank Overgas Inc AD (M.Eng. Donka Bukolska and M.Eng. Nikolay Hristov) for providing data for the techno-economic model setup.

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List of Abbrevations

Abbrevation	**Meaning**
API	Application Programming Interface
ASU	Air Separation Unit
bn€	Billion Euro
BHA	Bottom Hole Assembly
CAPEX	CAPital EXpenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CH_4	Methane
COM	Component Object Model
C_2H_6	Ethane
C_3H_8	Propane
COE	Cost Of Electricity
CO	Carbon monoxide
CO_2	Carbon dioxide
CRIP	Controlled Retraction Injection Point
CV	Calorific Value
DCD	Dobrudzha Coal Deposit
EOS	Equation Of State
H_2	Hydrogen
HEIG	High Energy Intensity Growth
IECM	Integrated Environmental Control Model
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
k€	Thousand Euro
LEAP	Long Range Energy Alternatives Planning System

Abbrevation	**Meaning**
LEIG	Low Energy Intensity Growth
LR	Long Radius
MEIG	Medium Energy Intensity Growth
M€	Million Euro
MEA	MonoEthanolAmine
MPa	MegaPascal
MR	Medium Radius
N_2	Nitrogen
OPEX	OPerational EXpenditure
OAT	One-At-a-Time sensitivity analysis
O_2	Oxygen
PP	Power Plant
SR	Short Radius
SEI	Stockholm Environmental Institute
UCG	Underground Coal Gasification
WEPP	World Electric Power Plants Database

List of Symbols

Symbol	Meaning	Dimension
η	Effiency	%
η_{UCG}	UCG gasification efficiency	%
ρ	Density	kg/sm^3
$A+B$	Parameters of Churchill-Bernstein equation	-
C_{aC}	Annual capital costs	€/year
C_{aD}	Constant annual depreciation costs	€/year
C_{aI}	Annual interest payment	€/year
C_{aRD}	Annual costs of restoration and demolition	€/year
C_{aTI}	Annual tax and insurance burden	€/year
C_{aLT}	Levelized total annual costs	€
C_{awD}	Total annual costs without demolition	€/year
C_{OP}	Total annual operating costs	€/year
C_D	Demolition costs	€/year
C_M	Operational and maintenance costs	€/year
C_P	Personnel costs	€/year
C_{fO}	Fixed operating costs	€/year
C_{vO}	Variable operating costs	€/year
C_{Comp}	CAPEX compressors	€
C_{Pump}	CAPEX pumps	€
C_C	Capital costs	€
C_I	Total power plant investment costs	€
C_{IB}	Buildings owner contribution	€
C_{Is}	Specific investment costs	€
C_{CvaC}	Capital value annual capital costs	€
C_{CvaF}	Capital value annual fuel costs	€

Symbol	Meaning	Dimension
C_{Cvo}	Capital value of the overall costs	€
C_{CvaO}	Capital value annual operating costs	€
CR	Compression ratio	-
CV_{Syn}	Synthesis gas calorific value	MJ/sm^3
CV_{Coal}	Coal calorific value	MJ/kg
d	Inner liner diameter	cm
g	Gravity constant	m/s^2
E_p	Produced electricity	MWh
F_f	Fanning friction factor	-
H_{fl}	Annual full load hours	hours
HV	Heating value	kJ/mol
i	Iteration counter	-
i_r	Nominal interest rate on planning horizon	%
ir_{DC}	Nominal interest rate for restoration/demolition	%
k_s	Specific heat	-
LHV_{CCGT}	Heat input CCGT power plant	MW$_{th}$
m	Mass flow	t/day
m_{Coal}	Required daily coal amount	t/day
M	Molecular weight	kg/mol
n	Years of operation	years
n_p	Planning horizon	years
n_A	Imputed fiscal depreciation period	years
N_t	Number of parallel compressor trains	-
O_y	Observation year n	year
p_{ASU}	Pressure at ASU outlet	MPa
p_{BHP}	Bottom hole pressure	MPa
p_{CO}	Cut-off pressure	MPa
p_{WHP}	Well head pressure	MPa
p_{co}	Critical pressure	MPa
p_{in}	Compressor inlet pressure	MPa
P_{net}	Installed net capacity	MW$_{el}$
q_{Syn}	Synthesis gas volume flow	sm^3/h

Symbol	Meaning	Dimension
r	Radius	m
R	Gas constant	kJ/(kmol-K)
R_i	Nominal interest rate	%
Re	Reynold's number	-
t_{Coal}	Tonne of gasified coal	t/day
T	Temperature	°C
T_{in}	Temperature at compressor inlet	°C
w	Velocity	m/s
W	Power requirement	MW
W_p	Power requirement for pumping	MW
X	Mass fraction	%
X_{Syn}^{Coal}	Produced synthesis gas per gasified coal unit	-
z	Iteration depth	-
Z_s	Compressibility	-

Subscripts

Symbol	Meaning
CH_4	Methane component
CO	Carbon monoxide component
el	Electric
i	Iteration counter
H_2	Hydrogen component
th	Thermal

1 Introduction

Electrical energy is an indispensable component of basic services and standard of living for the modern society and economy. In order to meet challenges in the energy sector such as climate change due to increasing anthropogenic greenhouse gas emissions, increasing import dependency as well as an economic and safe energy supply, the EU developed market-dependent instruments (e.g. taxes, subsidies, CO_2 emission charges, etc.). These instruments aim at the support of the development of sustainable energy technologies (energy efficiency, renewable energy, low-emission technologies). According to MEW (2012), one important aim of the EU strategies is to reduce CO_2 emissions based on those of 1990 by 20 % until 2020 and by 80 % until 2050 via an increase of technical efficiency (e.g. power plant efficiency, thermal insulation of buildings to reduce heat emissions), the implementation of renewable energy (e.g. wind power, biomass, solar power) and clean coal technologies (e.g. increase of production efficiency, CCS). Further important EU measures for a safe energy supply target at a reduction of the EU dependence on primary energy imports and protect the economy from fluctuating energy costs since currently, the EU imports more than 50 % of the primary energy requirements from non-EU countries (COEC, 2007; EC, 2008; EU, 2013; EurActiv, 2010; BMU, 2011). However, according to Capros et al. (2009), EU27 energy trends to 2030 demonstrate an increase of primary energy import dependency in Europe by 4 % compared to 2010 (55 % in 2010, up to 60 % in 2030). Amongst others, this relates to cost-intensive and yet non-convertible conventional hard coal mining due to great coal seam depths and complex geological boundary conditions. In Europe, merely 4 % of theoretically existent coal resources are available as coal reserves (Rempel et al., 2007; EURACOAL, 2008; Kempka et al., 2009). At this point, underground coal gasification (UCG) can provide an economical approach for the utilization of deep-seated coals that are technically and economically not exploitable by conventional mining. Taking into account the theoretically existent coal resources exploitable via UCG, an independent energy supply could be ensured for further 70 years in Europe and for 270 years world-wide (Kempka et al., 2009).

Principle of Underground Coal Gasification

UCG bases on the principle of the borehole mining, whereby the target coal seam is developed using injection and production wells. Through the injection wells, an oxidizer, generally consisting of O_2, N_2 and vapor, is injected in order to ignite the target coal seam. During the in-situ sub-stoichiometric combustion process, coal is converted into a high calorific synthesis gas transported above ground via production wells. After its processing, UCG synthesis gas is applicable for different end-uses, as e.g. chemical raw material, liquid fuel, hydrogen, fertilizer or for electricity production. Figure 1.1 shows a coupled UCG-CCGT-CCS process, whereby UCG synthesis gas is utilized to fuel a CCGT power plant with carbon capture and storage. Thereby, CO_2 generated during coal gasification and electricity production is captured and stored in the abandoned UCG gasification reactors underground. The UCG technology most suitable

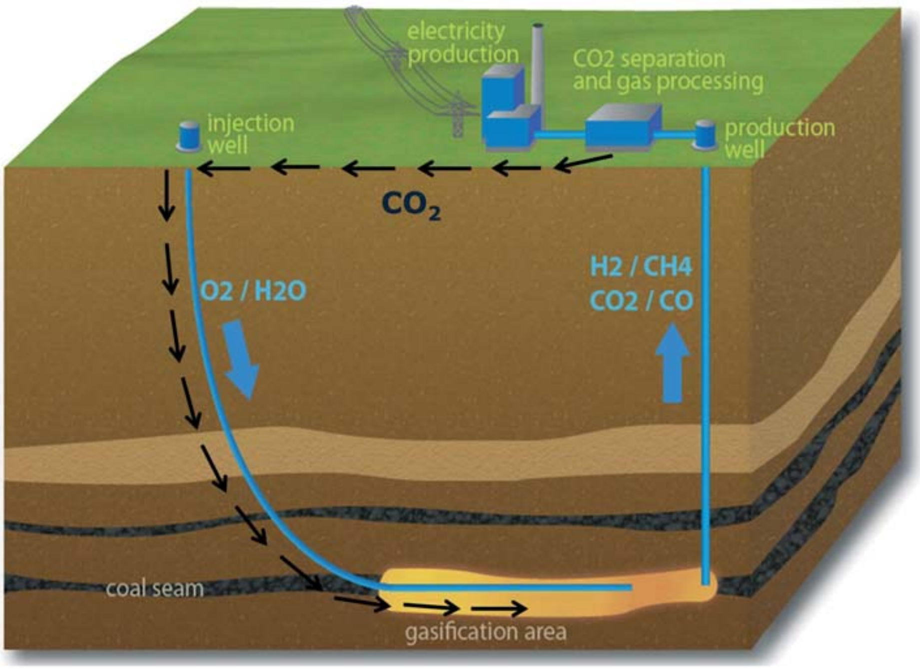

Figure 1.1: Schematic of a UCG process coupled to electricity generation with CO_2 capture and storage in the former UCG voids, modified from Kempka et al. (2009).

for deep-lying coal seams is the Controlled Retraction Injection Point (CRIP) technology that allows for a secure gasification process by controlling the oxidizer injection point within the coal seam (Hewing et al., 1988; Prabu and Jayanti, 2011; Nakaten et al., 2014b). Thereto, a drilling infrastructure consisting of vertical wells for injection and production and a network of lined deviated injection wells, drilled horizontally into the coal seam, are required. In order to position the injection point during the UCG process, an inner coiled tubing is introduced into each deviated well. The liner can be retracted backwards to virgin coal, as soon as the current gasification reactor has reached its envisaged size and the synthesis gas quality declines. As illustrated in Figure 1.2, the obtained gasification channel structure resembles a string of beads (Hewing et al., 1988; Prabu and Jayanti, 2011; Nakaten et al., 2014b). Compared to conventional coal mining, UCG has remarkable advantages, such as a higher resource utilization efficiency, straight implementation options of frontier technologies (e.g. CCS and intermediate gas storage) as well as additional energy reserves from unmineable hard coal (reduction of import dependency). Nevertheless, hazards may occur due to complex chemical and physical processes during the gasification process. For instance, in case of gas losses UCG may contaminate adjacent aquifers. Furthermore, extracting larger amounts of coal can impact roof integrity and promote gas leakage from UCG reactors. Thereby, the risk of groundwater contamination is lower in deep coal seams as potable groundwater horizons occur closer to the surface. The mentioned potential hazards presuppose a careful UCG-CCS site selection, comprising detailed structural geological and hydrogeological knowledge of the particular coal deposit.

History of Underground Coal Gasification

Underground coal gasification is not an idea of nowadays, but has a long history. Its roots go back to the 1860s, whereby since then the idea of UCG caused attention e.g. as bypass to the hard work in the mines of the socialist society, during the oil crisis in the 1980's or as an option for exploitation of deep lying, high quality coal not accessible via conventional coal mining (GVSt, 2005; Burton et al., 2006). In 1868, the brothers Werner and Wilhelm Siemens developed a concept for the control and utilization of underground coal fires, whereupon they suggested the underground gasification of waste and slack coal in the mine. About the same time, the Russian chemist Dmitri Mendeleyev developed the idea of controlled coal self-ignition via injection wells. In the early 20^{th} century the British scientist Sir William Ramsay prepared the first UCG trial near Durham (UK), but before the experiment was started, Sir William Ramsey died and his research was interrupted by the outbreak of World War I (1914). In 1928, Kirichenko started planning the first Soviet UCG program. Its implementation began in Lisichansk in 1932. In the 1950 to 1960's, independent Polish, Czech, US and Chinese efforts were undertaken. First Australian and European pilots were established in the 1980s (Franke and Beckervordersandforth, 1978; Ledent et al., 1981; Ledent, 1981; Hewing et al., 1988; Blinderman, 2002; Beath, 2006; Burton et al., 2006; Kempka et al., 2009; Klimenko, 2009; Benderev and Bojadgieva, 2011). Nowadays, UCG pilots are still operated in Europe, US, Canada, Australia, China and South Africa. About 50 small UCG pilot installations have been tested until now.

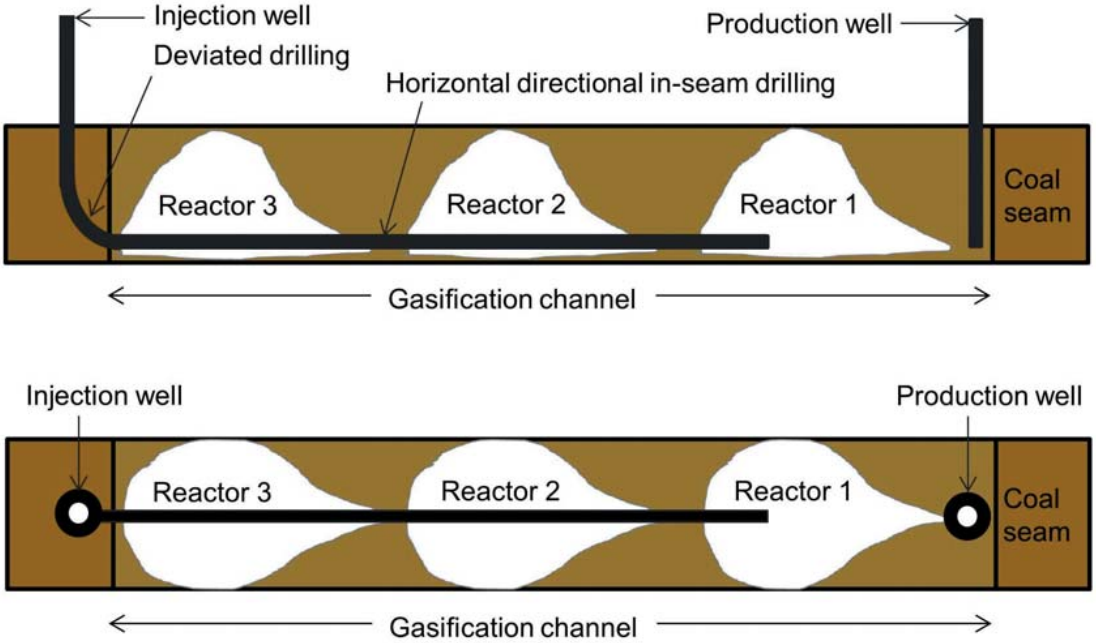

Figure 1.2: Schematic a) horizontal and b) vertical cross sections of three UCG reactors developed by the CRIP technology, modified from Kempka et al. (2011a).

1.1 Challenges in the Bulgarian Energy Sector

Despite collaborative objectives and initiatives to ensure energy supply in the EU, the energy sector is not in the authority of the European Union, but according to the Treaty Establishing of the European Community (TEC), it is part of the „shared responsibilities“ between member states and community requiring subsidiary actions. Thus, it is the responsibility of each member state to take individual decisions on their energy supply and the domestic energy mix (Klaue and van de Loo, 2005, 2006). For Bulgaria, the EU targets based national energy strategy until 2020 is given by the Energy Strategy Paper for Reliable, Efficient and Cleaner Energy (MEET, 2011b). However, comparing the EU environmental and the national energy strategies with the current characteristics of the Bulgarian energy sector reveals issues that may hamper the achievement of the environmental targets. These are e.g. a high primary energy import dependency, a low energy production efficiency and a high share of fossil fuel in the overall energy mix. The Bulgarian energy production strongly relies on lignite and coal products, obtaining a share of nearby 60 % in the overall energy mix in 2010. Thereby, according to the Bulgarian Energy Strategy Paper for Reliable, Efficient and Cleaner Energy, lignite will remain an essential source for energy supply during the next decades (MEET, 2011b). Furthermore, the CO_2 emission-intensive energy production in Bulgaria is associated with a technically outdated power generation system. Almost 50 % of all power plants exceed the average power plant lifetime of

40 years and average fossil fueled power plant efficiency in 2009 amounts to 33 % (Pandelieva, 2009). Another weak point of the Bulgarian energy sector is its high reliability on primary energy carrier imports, obtaining up to 70 % of its fossil fuel and uranium demand from the Russian Federation and the Ukraine (Bulgartransgaz, 2013; Lefkowitz, 2012).

1.2 UCG-CCGT-CCS Economic Assessment

Aiming at an independent energy supply, UCG combined with CCS is an emission neutral option to develop resources not exploitable via conventional mining while supporting the decarbonisation of the Bulgarian energy system until the full transition towards a renewable energy supply has succeeded. As economics have a significant impact on the viability of research ideas, the aim of this thesis is to assess UCG cost effectiveness focusing three key objectives. Since in the present study the economic investigation of UCG synthesis gas application is focused on electricity generation in an aboveground CCGT power plant, the first objective is to develop an instrument for site specific UCG-CCGT-CCS COE quantification and its exemplary application at a selected target area in Bulgaria. The assessment of possible UCG-CCGT-CCS COE variation bandwidths related to uncertainties due to e.g. lack of data or changing model boundary conditions, especially the quantification of these uncertainties, is the second objective. Besides site-specific constraints, UCG-CCGT-CCS competitiveness strictly depends on geographical and infrastructural boundary conditions. Thus, the third objective of the present study is to assess economical and CO_2 mitigation potentials UCG-CCGT-CCS may offer to the Bulgarian energy system. This includes assessing the economic effectiveness of substituting natural gas imports by feeding natural gas quality UCG synthesis gas into the national gas pipeline network.

1.3 Modeling Based Investigation Approach

To enable the economic assessment, a techno-economic model is developed to determine costs of electricity (COE) for a coupled UCG system considering air separation, oxidizer injection and compression, the UCG process, synthesis gas processing, electricity production as well as post combustion CO_2 capture and geological storage. The flexible scalable model is applicable to calculate UCG-CCGT-CCS COE for any selected target area world-wide taking into account site-specific geological, chemical, technical and market-dependent constraints. In the present study UCG-CCGT-CCS COE determination is exemplified for a selected target area in Bul-

garia. The model setup, assigned boundary conditions and the calculation results are discussed in Chapter 2, *Techno-Economic Model Developed for UCG-CCGT-CCS COE Determination*.
To handle the effect of e.g. data uncertainties by examining their impact on COE and quantify resulting UCG-CCGT-CCS COE variation bandwidths, one-at-a-time and multivariate sensitivity analyses are applied. The investigated model input parameters are categorized into geological, chemical, technical and market-dependent constraints. Sensitivity analyses results are presented in Chapter 3, *Uncertainty Assessment of Site Specific Model Constraints*.
UCG-CCGT-CCS process implementation into the overall Bulgarian energy network system is undertaken by coupling the developed techno-economic model with the macro scale energy system-modeling framework LEAP (Heaps, 2012). The elaborated UCG-CCGT-CCS and CCS equipped power plants (CCS-PP) implementation concepts, the LEAP software tool, model boundary conditions as well as the obtained simulation results are presented and discussed in Chapter 4, *UCG-CCGT-CCS Implementation*. Energy production output, CO_2 emission and COE until 2050 are modeled for a UCG-CCGT-CCS scenario, a CCS-PP scenario and a baseline scenario (without UCG-CCGT-CCS and CCS-PP but renewable energies and nuclear power supply) in order to evaluate the prospects of achieving the EU environmental targets in Bulgaria with and without UCG-CCGT-CCS and CCS-PP.
In Chapter 5 *Summary, Conclusions and Outlook*, the obtained results are summarized concluding that UCG-CCGT-CCS and CCS-PP are essential and economic alternatives to conventional Bulgarian fossil fuel power generation and that UCG synthesis gas is a competitive option to decrease Bulgaria's natural gas import reliability by 100 %. Potential further techno-economic model developments and future research activities are addressed in the outlook.

2 Techno-Economic Model Developed for UCG-CCGT-CCS COE Determination

Economics have a significant impact on the viability of research ideas thus, assessing process cost effectiveness is an important issue of applied research activities. In order to assess the economics of underground coal gasification coupled to a combined cycle (CCGT) power plant with subsequent carbon capture and storage (CCS) in the UCG voids resulting from coal consumption, a yet non existent techno-economic model consisting of six sub-models is developed. In the current study, UCG-CCGT-CCS cost of electricity (COE) determination is exemplified for a chosen coal deposit in Bulgaria. Location and name of the selected target areas are anonymized in this thesis, but the geological data considered for the simulations are itemized accordingly. Being determined by 130 model variables and allowing to account for an individual operational process design, the model is applicable for any (local scale) study area world-wide, taking into account accordant site-specific geological (e.g. seam depth, thickness, extent, etc.), chemical (synthesis gas composition), technical (e.g. power plant, well layout, compressors and pumps, etc.) and market-dependent (e.g. CO_2 emission charges, synthesis gas processing costs, drilling costs, oxidizer production costs) model boundary conditions. The model setup and calculation results discussed in Chapter 2 recline on Nakaten et al. (2012).

2.1 Geological Background of the Target Area in Bulgaria

The selected target area is a fault bounded coal deposit in Bulgaria with an extent of about 420 km^2. Its lithological structures, genesis and tectonic development are well explored by geological and geophysical investigations undertaken in the period from 1960 through 1986, especially during oil and gas exploration in 1962. According to Benderev and Bojadgieva (2011), the high rank bituminous coal bearing Upper Carboniferous layers have a total thickness of 1,000 m with prevailing slopes of 10 ° to 15 °, and are covered by Permian to Quaternary rocks. Thereby, the Carboniferous layers are faulted by almost vertical tectonic fractures in sub-meridian direction and an amplitude of 100 m. Between the Carboniferous and a thick Lower Cretaceous/Upper Jurassic aquifer reside rocks of Permian to Middle Jurassic age with different thicknesses and permeability. Above the shallowest part of the coal deposit, 20 m to 50 m thick Middle Jurassic water permeable sediments are deposited there, whereby the sediments in the Northern and Eastern parts are of Perm-Triassic and Lower Jurassic age. The latter ones have a low permeability and a thickness of several hundred meters. Although the coal deposit is one of the most prospective Bulgarian areas for exploitation providing high coal qualities, the deep-seated coal seams (average depth 2,000 m) are not suitable for conventional mining. Hence, investigations undertaken in the context of the UCG&CO_2STORAGE EU project (feasibility study) examine whether UCG could be an alternative exploitation method to utilize the resources (OVERGAS, 2013). For the target area examination, 120 geological sections of deep coal wells with an average depth of 2,000 m, 100 geological sections of shallow wells with an average depth of 500 m, and well log data for all 120 deep wells, were taken into account. Project specific geological surveys show, that the overall research area provides seven coal seams suitable for a UCG-CCS application. Considering threshold limits of parameters (such as e.g. seam extent, average coal seam thickness, an adequate separation distance between the coal seams and the surrounding faults, availability of coal resources, dip of the coal seam, chemical/physical coal characteristics, hydrogeological conditions, UCG process configuration, etc.) four coal seams providing ample fuel to supply a coupled combined cycle gas turbine (CCGT) power plant for electricity generation were selected (cf. Figure 2.1). The four coal seams are parceled into

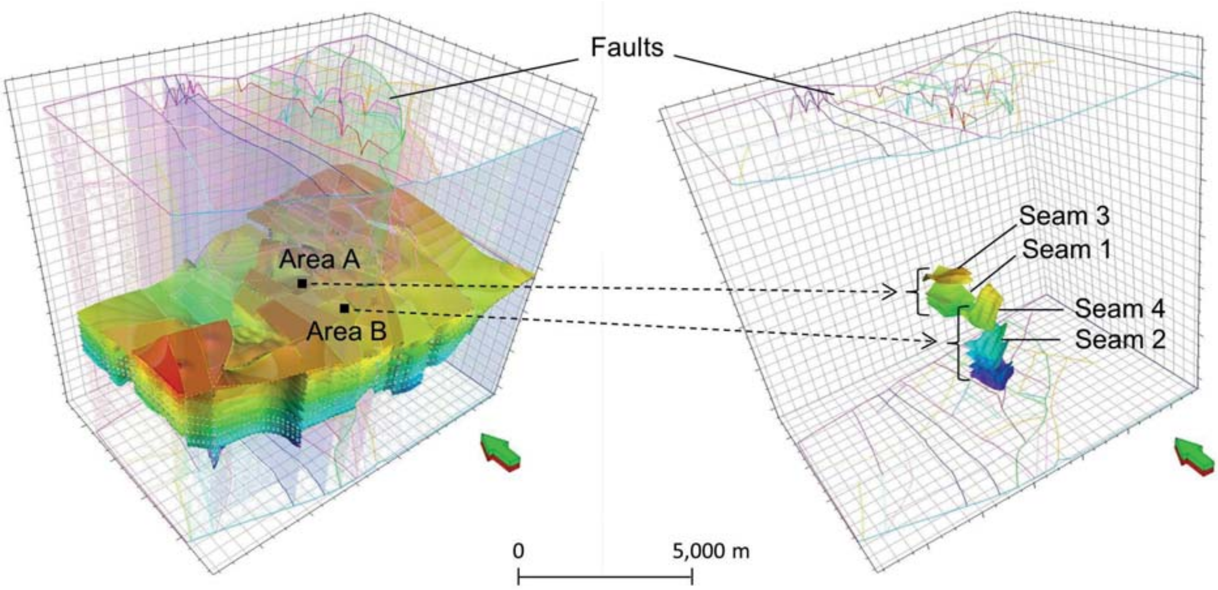

Figure 2.1: Geological model of the coal deposit, the two target areas and selected target coal seams, modified from Nakaten et al. (2012).

two target areas that are approximately 2 km apart from each other. Synthesis gas should be produced in both areas simultaneously to fuel the intermediate placed CCGT power plant (Chapter 2.2.4, *UCG Exploitation Scheme*).

2.2 UCG-CCGT-CCS Commercial-Scale Setup for the Target Area

Basic boundary conditions and assumptions such as synthesis gas composition, CO_2 emission handling strategy, pressure loss in injection and production wells, well layout and diameters relevant to set up a commercial scale scenario for the target area, are discussed in Chapter 2.2.

2.2.1 Synthesis Gas Composition

The synthesis gas composition considered for the present investigations (N_2 = 35 %, CO = 10 %, H_2 = 21 %, CH_4 = 11 %, CO_2 = 23 %) bases on former UCG trials undertaken at great depths, assuming an oxygen-nitrogen ratio of 60 % to 40 % and is an internal project assumption. The amount of produced synthesis gas per tonne of gasified coal (X_{Syn}^{Coal}) is calculated applying Equation 2.1 and amounts to 2,843 sm^3/t. Thereby, a UCG gasification efficiency (η_{UCG}) of 62.5 %, a synthesis gas calorific value (CV_{Syn}) of 7.50 (MJ/sm^3) and the coal calorific values (CV_{Coal}) listed in Table 2.2 were considered. Table 2.1 presents the parameters required to determine the produced synthesis gas amount per tonne of gasified coal, the volume flow per hour and the synthesis gas calorific value (average value of all target coal seams).

Table 2.1: Parameters used to calculate the amount of produced synthesis gas per tonne of gasified coal (cf. Equation 2.1), hourly volume flow (cf. Equation 2.3) and synthesis gas calorific value unsing Equation 2.4), calculation results from Nakaten et al. (2014b).

CV_{Syn}	Synthesis gas CV (MJ/sm^3)	7.5	Calculated
η_{UCG}	UCG gasification efficiency (%)	62.5	Green (2011)
m_{Coal}	Required daily coal amount (t)	3,013	Calculated
X	Mass fraction of H_2/CH_4/CO (%)	21/11/10	Assumed

According to Equation 2.2, the heat input (LHV_{CCGT}) for the 308 MW_{el} CCGT power plant is determined by the required coal amount in tons per day (m_{Coal}), the coal calorific value as well as the UCG gasification efficiency (η_{UCG}) and amounts to 743 MW_{th}. Based on the determined heat input and synthesis gas CV_{Syn}, Equation 2.3 is used to calculate the required synthesis gas volume flow (q_{Syn}) to operate the CCGT power plant. In turn, the synthesis gas calorific value (cf. Equation 2.4) is calculated from the synthesis gas composition as well as the corresponding gas component mass fractions and heating values (HV). Determination of synthesis gas composition, and thus synthesis gas CV_{Syn} taking into account site-specific geological, thermodynamic UCG operating conditions, requires specific process modeling not considered in the present study. However, synthesis gas CV_{Syn} and coal CV_{Coal} are indirectly linked via Equation 2.1 determining the recoverable synthesis gas amount per tonne of gasified coal, which was validated against a (project intern) database of UCG projects carried out world-wide.

$$X_{Syn}^{Coal} = \frac{CV_{Coal} \cdot \eta_{UCG}}{CV_{Syn}} \tag{2.1}$$

$$LHV_{CCGT} = m_{Coal} \cdot CV_{Coal} \cdot \eta_{UCG} \tag{2.2}$$

$$q_{Syn} = \frac{LHV_{CCGT}}{CV_{Syn}} \tag{2.3}$$

$$CV_{Syn} = X_{H_2} \cdot HV_{H_2} + X_{CH_4} \cdot HV_{CH_4} + X_{CO} \cdot HV_{CO} \tag{2.4}$$

2.2.2 CO_2 Emission Handling Strategy

In line with the present study's concept of storing CO_2 in-situ in the former UCG voids as discussed in Burton et al. (2006); Friedmann et al. (2009); Kempka et al. (2011b); Sarhosis et al. (2013), carbon dioxide resulting from UCG and electricity generation is separated from the synthesis gas stream by an amine-based scrubber using monoethanolamine (MEA). Amine solvents chemically react with CO_2 under certain conditions, and the treated gas exits at the top of the absorber, while the amine (mixed with CO_2) exits at the bottom (Ramezan et al., 2007). The flue gas is cooled with a direct contact cooler and ducted to the MEA system, where CO_2 is removed, compressed, and liquefied for storage in the voids resulting from the underground coal consumption.

The first gasification period is undertaken without CO_2 capture and storage (the first gasification channel is in operation and no CO_2 can be stored simultaneously), taking into account a fixed emission charge of 25 €/t CO_2 for 100 % of the emitted CO_2. As the first gasification reactor is outgassed, the capture rate is adjusted to the available storage capacity of the UCG reactors (20.5 %), whereby the remaining 79.5 % CO_2 which cannot be stored in the UCG cavities are released into the atmosphere, paying CO_2 emission charges.

CO_2 Storage Capacity Determination

To determine CO_2 storage potential in the residual coal as well as in the UCG cavities generated in the coal seams after gasification, Kempka et al. (2011a) performed various laboratory experiments applying sorption experiments described by Krooss et al. (2002); Siemons and Busch (2007) and Busch et al. (2008). Thereby, three hard coals of different rank from German mining districts were gasified in a laboratory-scale reactor. Using high-pressure CO_2 excess sorption isotherms before and after the gasification process, Kempka et al. (2011a) show that physical sorption represents an additional option for CO_2 storage in the underground UCG reactors as well as in the surrounding by revealing an increased sorption capacity of 31 % to 42 % (equivalent to 30 m^3/t to 41 m^3/t coal) after gasification. Besides, the initial porosity of the coal surrounding the cavity was about 2.0 % before and increased up to 24.5 % after the gasification process (Kempka et al., 2011c).
However, as it was not the aim of the present thesis, assessment of sorption capacity and porosity were not undertaken for the Bulgarian target area. Since coal sorption capacity and porosity strongly relate to in-situ boundary conditions and Kempka et al. (2011a) assessed German coal samples at laboratory scale, the boundary conditions, and hence the resulting values are not transferable to the Bulgarian study area. Besides, considering an increased coal porosity (up to 24.5 % after gasification compared to 2 % prior gasification) in an assumed UCG reactor vicinity of 1 m to 5 m, overall CO_2 storage capacity in the present study would increase insignificantly by 0.2 % to 1 % (void volume of 15,024 m^3 to 75,120 m^3 for additional storage).
Thus, in the present study, CO_2 storage capacity in UCG voids was determined conservatively by considering only the void volume of the radial UCG cavity geometry. The CO_2 density depending on temperature and pressure conditions in each seam after UCG shutdown and cooling to in-situ temperature, was calculated using the equations of state (EOS) after Kunz and Wagner (2012). Considering CO_2 densities between 818 kg/m^3 and 865 kg/m^3 at storage conditions in the four seams, a cumulative UCG void volume of 12.74 mio. sm^3 and a CO_2 amount of about 52.9 Mt (produced during UCG and electricity generation within 20 years), the average CO_2 storage capacity amounts to 20.5 %. Due to varying in-situ pressures from 13.2 MPa to 18 MPa and temperatures from 24.9 °C to 37.7 °C caused by different target coal seam depths, CO_2 densities in each seam differ slightly.

2.2.3 Pressure Loss in Injection and Production Wells

Pressure losses in injection and production wells caused by frictional forces have to be taken into account, when aiming optimized and save borehole mining operations as it is the purpose of the current study. Frictional forces in wells correlate significantly with varying properties of different gas compositions (oxidizer and synthesis gas compositions), thus the pressure management has to be adjusted accordingly. In order to calculate well head pressures (p_{WHP}) based on the hydrostatic bottom hole pressure (p_{BHP}) and vice versa, an iterative approach considering the pressure- and temperature-dependent gas mixture density determined using the EOS by Kunz and Wagner (2012) was implemented into the techno-economic model. According to Equations 2.5 and 2.6, p_{WHP} and p_{BHP} are calculated as follows:

$$p_{WHP} = p_{BHP} - \sum_{i=1}^{n} \frac{\rho(p_i, T_i) \cdot g \cdot z}{i} \tag{2.5}$$

$$p_{BHP} = p_{WHP} + \sum_{i=1}^{n} \frac{\rho(p_i, T_i) \cdot g \cdot z}{i} \tag{2.6}$$

In both equations, the gas mixture density at the pressure and temperature conditions for a depth z is represented by $\rho(p_i, T_i)$, whereby z is defined by the discretization interval i (number of iterations) and the gravity constant g. In the current study 100 iteration steps ($i = 100$) were found to be adequate to minimize calculation errors for the selected gas compositions and well depths. The algorithm was validated against real site data for CO_2 and N_2 single gases obtained from p_{BHP} and p_{WHP} measurements in the context of CO_2 storage operations at the Ketzin pilot site in Germany (Martens et al., 2012). To determine pressure- and temperature-dependent gas mixture viscosity (e.g. for the oxidizer or the synthesis gas) the approach of Chung et al. (1988) was implemented into the techno-economic model. Gas mixture compressibility and density calculations required for this purpose were conducted according to Kunz and Wagner (2012). In order to validate the implemented Chung et al. (1988) algorithm, results were compared to calculations undertaken, using the WebGasEOS tool developed by Reagan (2005) for gas mixtures of N_2, CH_4, CO_2, O_2, H_2, C_2H_6, and C_3H_8. Furthermore, the Chung et al. (1988) algorithm was validated against the EOS by Span and Wagner (1996) developed for CO_2 (single gas), resulting in acceptable deviations of 0.02 % to 2 %. However, due to lack of data the approach of Chung et al. (1988) for viscosity calculation of gas mixtures could not be validated in case of carbon monoxide in the present study. Thus, the carbon monoxide fraction in the synthesis gas is represented by CO_2 in the synthesis gas viscosity calculations.

Relevant parameters for determination of frictional pressure losses in wells are the Reynolds number (Re) and the Fanning friction factor (F_f). The Reynolds number is calculated according to Equation 2.7, representing a dimensionless number that defines the relation of inertial forces to viscous forces quantifying their influence on flow conditions. In Equation 2.7, the line velocity is represented by parameter w, whereby d_i is the inner liner diameter for the given interval i. The parameter $\rho(p_i, T_i)$ is determined after Kunz and Wagner (2012) and represents the gas mixture density, the gas mixture viscosity $\eta(p_i, T_i)$ was calculated using the Chung et al. (1988) approach.

$$Re = w \cdot \frac{d_i}{1000} \cdot \frac{\rho(p_i, T_i)}{\eta(p_i, T_i)} \tag{2.7}$$

The Fanning friction factor $F_f(p_i, T_i)$, a function of pipe roughness and the turbulence in liquid flows, is a dimensionless number calculated according to Equation 2.8. Terms A and B are adapted from the Churchill Correlation (Churchill and Bernstein, 1977).

$$F_f(p_i, T_i) = 2 \cdot [(\frac{8}{Re})^{12} + \frac{1}{(A+B)^{1.5}}]^{\frac{1}{12}} \tag{2.8}$$

Equation 2.9 (applicable for injection wells) and Equation 2.10 (applicable for production wells) consider all previously presented calculation steps to determine pressure losses in injection and production wells, by integrating Equations 2.7 and 2.8 into Equations 2.5 and 2.6. Considering UCG operation at hydrostatic pressure in the target coal seam, p_{WHP} for oxidizer injection varies between 14.91 MPa to 16.46 MPa (according to the respective target coal seams) and from 6.33 MPa to 7.86 MPa for CO_2 injection.

$$p_{WHP} = p_{BHP} - \sum_{i=1}^{n}(g + 2w^2 \cdot F_f(p_i, T_i) \cdot d_i) \cdot \frac{\rho(p_i, T_i) \cdot z}{i} \tag{2.9}$$

$$p_{BHP} = p_{WHP} - \sum_{i=1}^{n}(g - 2w^2 \cdot F_f(p_i, T_i) \cdot d_i) \cdot \frac{\rho(p_i, T_i) \cdot z}{i} \tag{2.10}$$

2.2.4 Well Layout and Diameters

For the UCG process setup in the current study, the CRIP technology was taken into consideration, since it provides better control on the gasification process than previously used UCG methods, and it also works well within thin coal seams (Ledent, 1981; Hewing et al., 1988; Burton et al., 2006; Kempka et al., 2009). To determine the optimal coal yield for the selected target coal seams, the required well number was calculated by considering the UCG reactor width and optimal well spacing for each seam (cf. Table 2.2). According to unpublished project internal data, a conservative seam thickness to cavity width ratio of 1:2 was assumed, as well as a reactor distance to seam thickness ratio of 2:1. The daily required amount of coal to fuel the coupled 308 MW CCGT power plant is 3,013 t, including the required coal to provide a power plant reserve margin of 10 %. The marginal differences in the required amount of coal are caused by the different coal calorific values of the four seams.

Table 2.2: Required injection well, gasification channel and production well number to exploit the target coal seams and parameters used for calculation (Nakaten et al., 2014b).

	Seam 1	Seam 2	Seam 3	Seam 4
Seam latitude (km^2)	1.14	0.62	1.14	0.62
Seam thickness (m)	4	6.6	11	12
Seam depth (m)	1,800	1,617	1,322	1,411
Coal calorific value (MJ/kg)	33.16	35.58	33.84	33.84
Required coal for CCGT (t/day)	3,100	2,870	3,040	3,040
Well spacing (m)	16	26	44	48
Gasification channel width (m)	8	13	22	24
Number of injection wells per seam	2	2	2	2
Number of gasification channels per seam	25	30	24	16
Number of production wells	2		2	

Inner Liner and Well Diameters

The UCG well layout has to be planned attentively to achieve a maximum coal yield while minimizing drilling and injection costs. Knowledge on well diameters is crucial for the well layout setup, whereby the minimal inner liner diameter was determined considering the oxidizer and CO_2 mass flow via the injection wells and the synthesis gas mass flow through the production wells, respectively. Attainable deviations (horizontal build-up rate) for deviated drillings in dependence of the well diameter according to Godbolt (2011), are presented in Table 2.3. According to the calculated CO_2 storage capacity in the UCG voids (20.5 %), 1.507 t CO_2 of 7.409 daily produced tonnes CO_2 (during gasification and electricity generation) are captured and injected with a rate of 8 t/well/hour. Taking into account 2.7 t oxidizer to gasify one tonne of coal (according to unpublished project database) and an average required daily coal amount of 3.013 t/day, the oxidizer mass flow rate amounts to 8.044 t/day, 335.1 t/hour and 41.9 t/well/hour respectively. The build-up rate for the eight injection wells taking into account average injection rates of 8 t/well/hour in case of CO_2 and 41.9 t/well/hour in case of oxidizer injection, is 60 °/30.48 m (short radius), resulting in a hole trajectory radius of 29 m. The hole trajectory radius is calculated using the cosine of the deviation angle and the deviated drilling length (in meters). The build-up rate for the production wells taking into account a production rate of about 92.8 t/well/hour amounts to 20 °/30.48 m (medium radius) achieving a hole trajectory radius of 87 m. The deviated drilling length (in meters) for one well is determined by the

Table 2.3: Achievable long (LR), medium (MR) and short radius (SR) build-up rates (deviations) during drilling in accordance to different wellbore size and inner liner diameters (Godbolt, 2011).

Horizontal class	Horizontal class identifier	Horizontal build-up rate (°/m)	Hole trajectory radius (m)	Wellbore size diameter (”)	Nominal BHA tool diameter (”)
LR	LRH2	2/30.48	873	4-3/4 to 8-1/2	3-1/2 to 6-1/2
LR	LRH4	4/30.48	437	4-3/4 to 8-1/2	3-1/2 to 6-1/2
LR	LRH6	6/30.48	291	4-3/4 to 8-1/2	3-1/2 to 6-1/2
MR	MRH8	8/30.48	218	4-3/4 to 8-1/2	3-1/2 to 6-1/2
MR	MRH12	12/30.48	145	4-3/4 to 8-1/2	3-1/2 to 6-1/2
MR	MRH16	16/30.48	109	4-3/4 to 8-1/2	3-1/2 to 6-1/2
MR	MRH20	20/30.48	87	6-1/2, 4-3/4	4-3/4, 3-1/2
MR	MRH25	25/30.48	70	6-1/2, 4-3/4	4-3/4, 3-1/2
MR	MRH30	30/30.48	58	6-1/2, 4-3/4	4-3/4, 3-1/2
MR	MRH35	35/30.48	50	4-3/4	3-1/2
MR	MRH40	40/30.48	44	4-3/4	3-1/2
SR	SRH45	45/30.48	39	4-3/4	3-1/2
SR	SRH50	50/30.48	35	4-3/4	3-1/2
SR	SRH55	55/30.48	32	4-3/4	3-1/2
SR	SRH60	60/30.48	29	4-3/4	3-1/2

quotient of the deviation angle (88.98 ° to 89.21 ° according to the different target coal seams) and the horizontal build-up rate per drilling meter. According to Godbolt (2011) deviations up to 6 °/30.48 m (LRH6 = long radius, horizontal, 6 °) are categorized as long radius, deviations up to 40 °/30.48 m (MRH40) as medium radius and deviations up to 60 °/30.48 m as short radius. Table 2.3 shows inner well diameters and the according achievable build-up rates, which in case of the injection wells amounts to 8.9 cm (3.5”) and in case of the production wells to 12.1 cm (4.75”). Considering an inner well diameter of 8.9 cm with an inner liner roughness of 0.0008 cm, a maximum vertical depth of 1,800 m, and an average oxidizer injection rate of 41.9 t/well/hour, pressure loss calculations (cf. Chapter 2.2.3, *Pressure Loss Calculation for Injection and Production Wells*) reveal an - in comparison to the required well head pressure - insignificant range of up to 0.42 MPa (cf. Figure 2.2). In case of CO_2 injection with an average injection rate of 8 t/well/hour, pressure loss amounts to 0.11 MPa in average and is negligible, if an inner liner diameter of at least 8.9 cm is applied (cf. Figure 2.2). The results for pressure loss

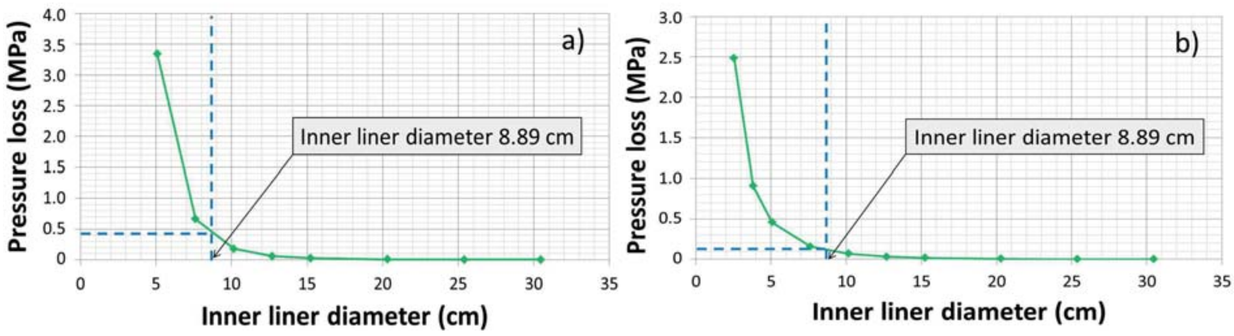

Figure 2.2: a) Pressure loss in injection wells during oxidizer injection (N_2-O_2 gas mixture, average injection rate of 41.9 t/well/hour) and b) CO_2 injection (CO_2 single gas, average injection rate of about 8 t/well/hour) with an inner liner roughness of 0.0008 cm, modified from Nakaten et al. (2014b).

calculations regarding the synthesis gas production (H_2-CH_2-N_2-CO_2 gas mixtures) through the four vertical production wells with a production rate of about 92.8 t/well/hour, are visualized in Figure 2.3. However, in order to examine potential chemical alterations due to progressive corrosion during long-term UCG operation (e.g. by H_2S and H_2O-CO_2 components in the synthesis gas), varying roughness from 0.0008 cm to 0.2 cm were observed.

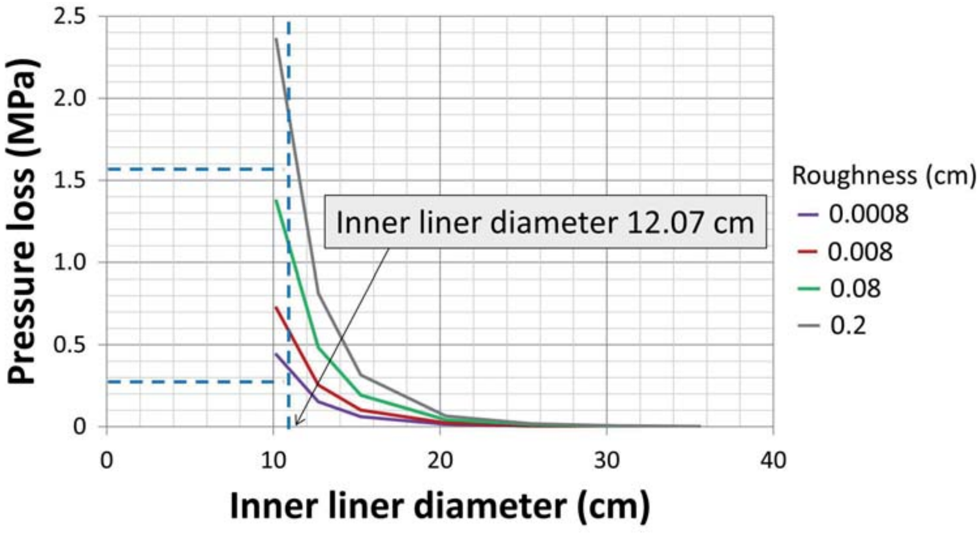

Figure 2.3: Pressure loss in synthesis gas production wells (H_2-CH_4-N_2-CO_2 gas mixture, production rate of 92.8 t/well/hour) for different liner roughness, modified from Nakaten et al. (2014b).

Taking into account the thermal regime in the target area, p_{WHP} for oxidizer and CO_2 injection and applying an inner liner diameter of 12.1 cm (4.75") with an inner liner roughness of 0.0008 cm, pressure loss amounts to 0.29 MPa and increases up to 1.59 MPa assuming a corrosion state (close to potential liner failure) of about 0.2 cm. Compared to the required well head pressures for oxidizer (14.5 MPa in average, cf. Table 2.6) and CO_2 injection (7 MPa in average, cf. Table 2.19), these values were considered to be in an acceptable range for the chosen liner diameters and well dimensions. Besides, inner liner diameters were optimized in order to keep pressure losses as low as possible.

UCG Exploitation Scheme

Based on previous well diameter calculations, horizontal build-up rates and injection pressure management, an exploitation scheme for a UCG-CCGT-CCS commercial-scale scenario for the target area was implemented. To avoid possible gas leakage from the UCG reactors due to e.g. negative mechanical impacts, an adequate horizontal safety distance to the bounding faults has to be maintained. According to project intern mechanical simulations, the safety distance to the faults has to be at least 150 m (cf. Figure 2.4).

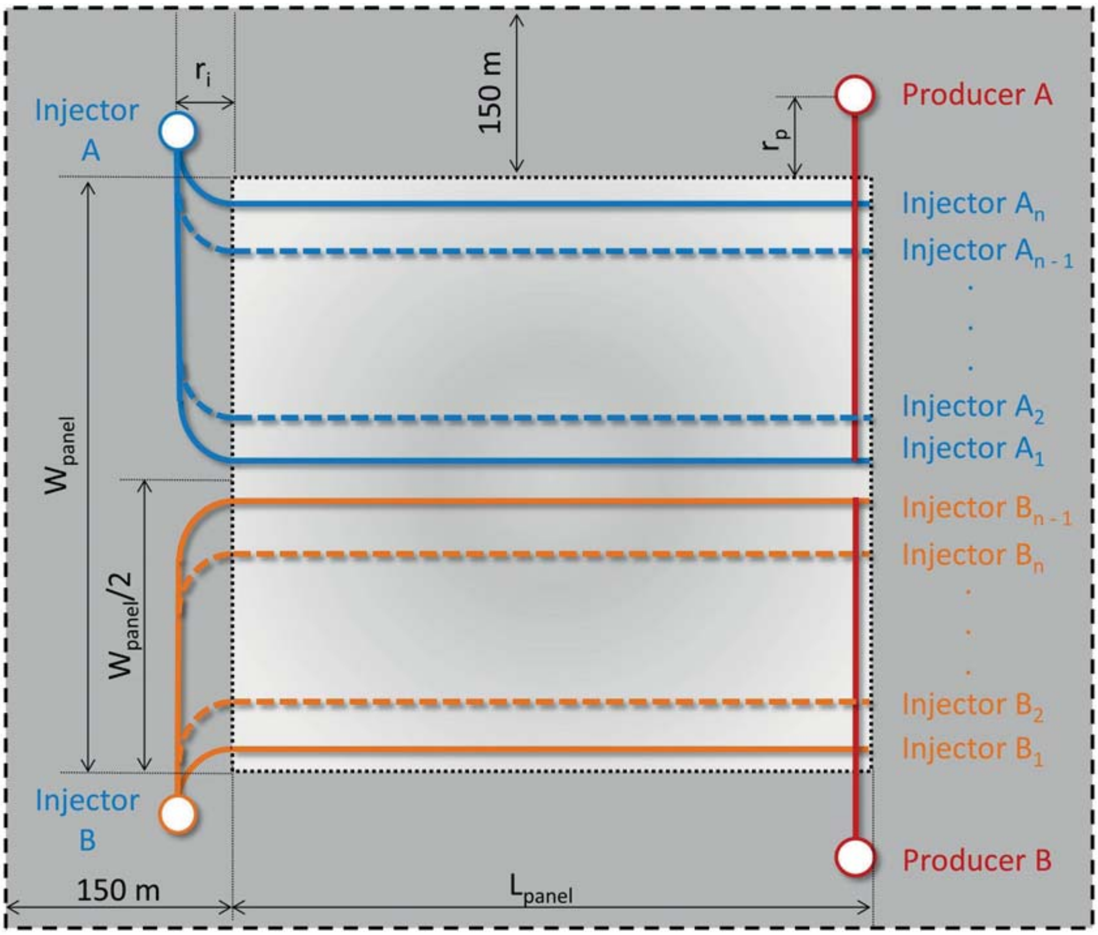

Figure 2.4: UCG well layout (cf. 3D view in Figure 2.5) for the selected target coal seams in a schematic, not to scale plane view, modified from Nakaten et al. (2014b).

The different hole trajectory radii for injection and production wells are represented by the radii r_i and r_p. Considering a daily gasification front progress in each gasification reactor of up to 3 meters per day, according to Luo et al. (2009) this was assumed as an achievable progress, two gasification channels per target area (four in total) have to be operated simultaneously in order to provide the required resources to operate the 308 MW CCGT power plant. Aiming at an individual control of the UCG process by managing oxidizer injection rates and liner retraction (CRIP), each UCG reactor is ignited by a separate liner. As depicted in Figure 2.4, target area exploitation is carried out by two vertical injection wells with n lateral legs (horizontal directional in-seam drillings) summing up to four injection wells for each area. To reduce pressure loss, four production wells each with one lateral leg per well, were considered to transport the produced synthesis gas aboveground. During the entire 20 year UCG-CCGT-CCS operational time 95 gasification channels, eight injection and four production wells have to be drilled. The current well layout allows for a total coal yield of about 45.4 %. A 3D-view of the exploitation scheme is shown in Figure 2.5.

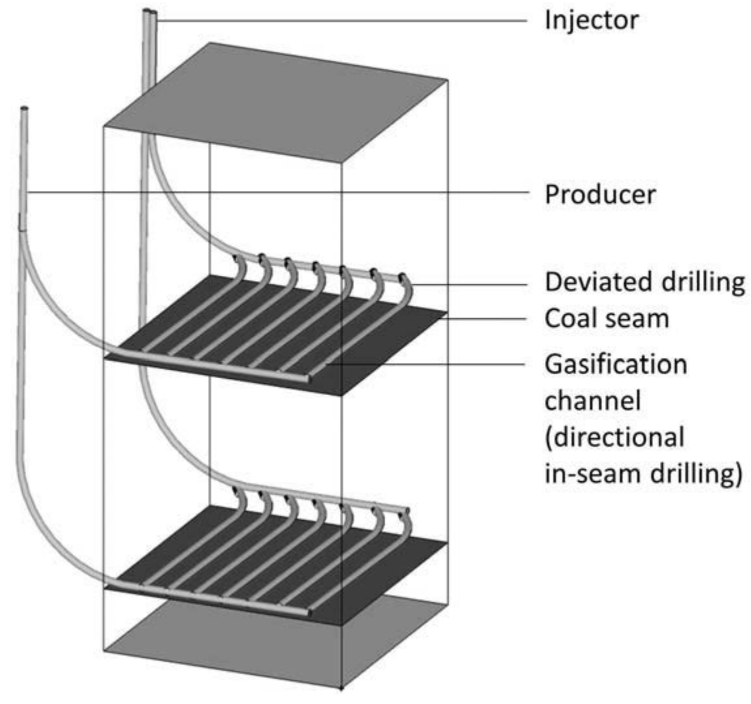

Figure 2.5: UCG development scheme in 3D view (not to scale), modified from Nakaten et al. (2014b).

2.3 Sub-Models and Modeling Results

In the present chapter the applied approach to determine capital expenditure (CAPEX) and operational expenditure (OPEX) for each process step of the combined UCG-CCGT-CCS system (cf. Figure 2.6) is discussed and calculation results are presented. The basic process layout for the techno-economic model contains six sub-models. An O_2-N_2 oxidizer mixture provided by an upstream air separation unit (1) is compressed and injected with water vapour via injection wells (2) into the target coal seam, where the UCG process takes place (3). The produced raw synthesis gas is transported above ground via production wells for processing (4). Subsequently, the processed synthesis gas is utilized for electricity generation in a CCGT power plant (5). CO_2 is captured, compressed and stored in the outgassed UCG voids (6). The dotted lines represent the internal energy flow of the process.

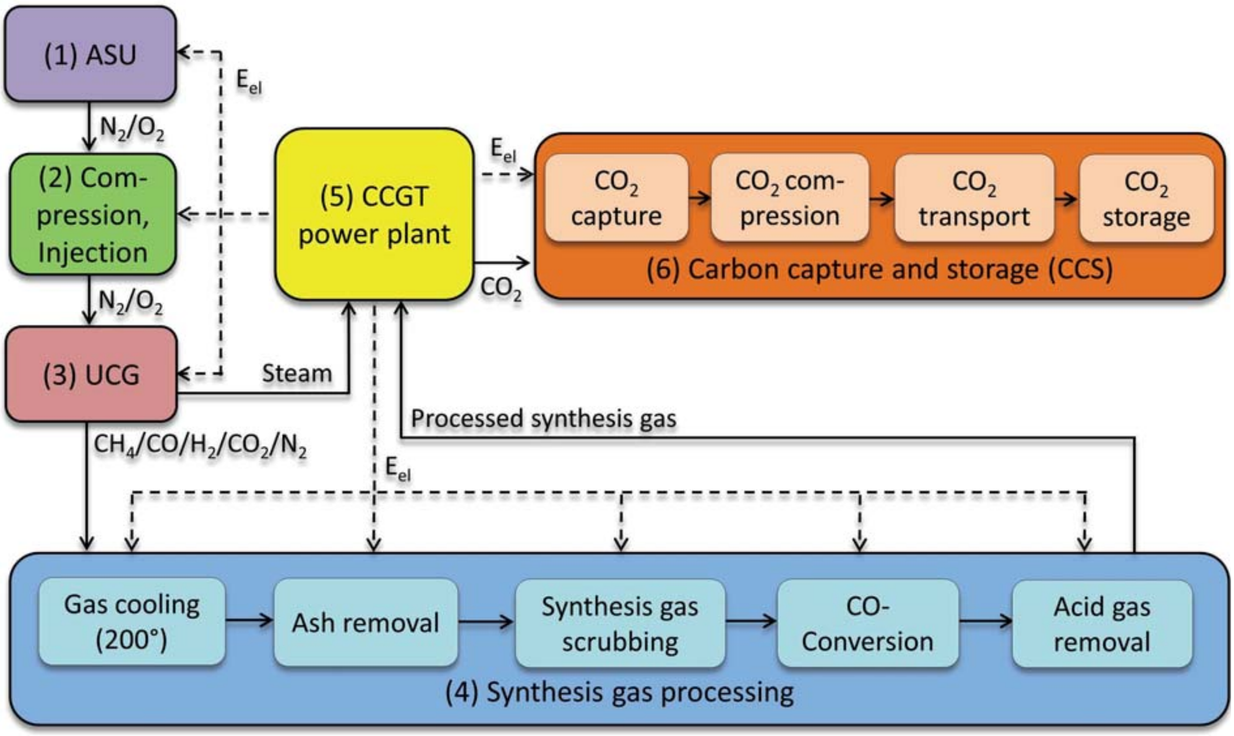

Figure 2.6: Techno-economic model developed for UCG-CCGT-CCS COE determination and its six sub-models, modified from Nakaten et al. (2012).

2.3.1 Air Separation Unit

In order to provide the oxygen required for the oxidizer composition (containing of N_2, O_2 and water vapor), the UCG-CCGT-CCS process is coupled to a cryogenic air separation unit, whereby nitrogen is rather a by-product of the air separation (ASU) process. In the present study it is considered, that N_2 and O_2 leave the ASU system at pressures between 0.5 MPa and 0.7 MPa (CEES, 2005; Gräbner et al., 2010; Kunze and Spliethoff, 2010; Lösch, 2013). CAPEX and OPEX for oxidizer production obtained from simulations using the IECM tool by (CEES, 2005) were measured for an entire plant lifetime of 20 years. Nevertheless, IECM engineering-economic simulation results (combined plant-level mass and energy balances with empirical data and process economics) are available for 200 MW and 400 MW plants only, thus the results had to be linearly interpolated to the dimensions of the overall UCG-CCGT-CCS process (cf. Table 2.4).

Table 2.4: OPEX and CAPEX calculated for the ASU process for the overall operational lifetime of 20 years (Nakaten et al., 2014b).

CAPEX	
Process facilities capital (€)	105,777,035
General facilities capital (€)	15,861,778
Engineer fees (€)	10,577,704
Contingency costs (€)	21,150,630
Interest charges (€)	8,251,946
Royalty fees (€)	528,885
Start-up costs (€)	3,796,316
Inventory (working) capital (€)	766,907
OPEX (variable and fixed costs)	
Electricity (€/year)	10,951,785
Operating labour (€/year)	2,160,496
Maintenance labour (€/year)	1,036,263
Maintenance material (€/year)	1,554,395
Admin and support labor (€/year)	1,107,284

The interpolation was undertaken by applying three average scaling factors considering the installed capacity, operating hours as well as oxidizer volume flows. As listed in Table 2.4, CAPEX sum up to 166.7 M€, total variable costs to about 11.0 M€ and total fixed costs to 16.8 M€. For the gasification of 1 t coal, 1.6 t O_2 (60 %) and 1.07 t N_2 (40 %) were taken into account, which results in a required daily amount of 4,826 t oxygen and 3,217 t nitrogen.

2.3.2 Oxidizer Compression and Injection

According to the economic model for CO_2 compression presented by McCollum and Ogden (2006), five stages were assumed to be appropriate for oxidizer (a mixture of 60 % O_2 and 40 % N_2) compression. Since the oxidizer compressibility (Z_s) and the ratio of specific heat (k_s)

are different at each stage, the calculation for compressor power requirement was conducted for each stage separately according to EOS by Kunz and Wagner (2012). The bandwidth of oxidizer compressibility and specific heat in the different stages are enlisted in Table 2.5.

Table 2.5: Power requirement calculated for oxidizer compression according to Equation 2.11, data from Nakaten et al. (2014b).

R	Gas constant (kJ/(kmol-K))	8.314
CR	Optimal compression ratio of each stage in average (MPa)	1.9
M	Oxidizer molecular weight (kg/kmol)	30.41
T_{in}	Oxidizer temperature at compressor inlet (°C)	40
η_{is}	Isentropic efficiency of compressor (-)	0.75
m	Average oxidizer mass flow rate (t/day)	8,043
Z_s	Oxidizer compressibility for each individual stage (-)	0.99 - 1.0
k_s	Ratio of specific oxidizer heat for each individual stage (-)	1.41 - 1.48
$W_{s,i}$	Total compression power requirement (MW)	16.25 - 20.58

The compressor power requirements for each individual stage should be added together to determine the total power requirement for oxidizer compression varying between 16.3 MW and 20.6 MW. This variation is caused by the different coal CV_{Coal} of the respective target coal seams (33.16 MJ/kg up to 35.58 MJ/kg, cf. Table 2.2), resulting in a differing daily required coal amount to supply the CCGT power plant (2,870 t/day to 3,100 t/day). Hence, the required oxidizer amount differs between 7,663 t/day to 8,277 t/day (cf. Table 2.6) causing different mass flow rates through the compressor train. The total power requirement for pumping (W_p) is calculated according to Equation 2.12 and range from 8.7 MW to 11.4 MW. The varying pumping power consumption is related to the different target coal seam depths, hence different well head pressures during injection. Calculation results are listed in Table 2.6 and expressed for the chosen reference year 2012. The cut-off pressure (p_{CO}) is the pressure at which compression switches to pumping, whereby ρ is the density of the oxidant during pumping at in-situ temperature and pressure. According to Equations 2.13 and 2.14 modified after McCollum and Ogden (2006), CAPEX for pumps (C_{Pump}) and compressors (C_{Comp}) were determined. Table 2.7 presents overall CAPEX and OPEX for oxidizer compression and injection.

$$W_{s,i} = m_{Zs} \cdot \frac{R \cdot T_{in}}{M \cdot \eta_{is}} \cdot \frac{k_s}{k_s - 1} \cdot (CR\frac{k_s - 1}{k_s} - 1) \tag{2.11}$$

$$W_p = \frac{m(p_{WHP} - p_{CO})}{\rho_{\eta_P}} \tag{2.12}$$

$$C_{Pump} = (1.11 \cdot W_p + 0.07) \cdot 10^6 \tag{2.13}$$

$$C_{Comp} = m \cdot N_t[0.13 \cdot (m)^{-0.71} + 1.40 \cdot (m)^{-0.60} \ln(\frac{p_{CO}}{p_{ASU}})] \tag{2.14}$$

Table 2.6: Calculation parameters to determine power consumption during oxidizer injection according to Equation 2.12 adapted from McCollum and Ogden (2006), data from Nakaten et al. (2014b).

		Seam 1	Seam 2	Seam 3	Seam 4
m	Oxidizer mass flow rate in average (t/day)	8,277	7,663	8,117	8,117
N_t	Number of parallel compressor trains (-)	1	1	1	1
p_{ASU}	Oxidizer pressure at ASU outlet (MPa)	0.6	0.6	0.6	0.6
p_{WHP}	Well head pressure (MPa)	16.46	14.91	12.89	13.56
p_{BHP}	Bottom hole pressure (MPa)	18.00	16.17	13.22	14.11
T	Temperature (°C)	37.69	32.80	24.92	27.31
p_{co}	Critical pressure oxidizer (MPa)	5.43	5.43	5.43	5.43
ρ	Oxidizer density during pumping (kg/sm^3)	124	117	107	110
η_P	Pump efficiency (-)	0.75	0.75	0.75	0.75
W_p	Required power for pumping (MW)	11.36	9.61	8.73	9.23

Table 2.7: CAPEX and OPEX for oxidizer compression and injection calculated according to Equation 2.12 presented by McCollum and Ogden (2006), data from Nakaten et al. (2014b).

	Seam 1	Seam 2	Seam 3	Seam 4
Total capital costs for compressor (M€)	29.25	27.53	26.91	27.35
Total capital costs for pump (M€)	12.68	10.741	9.76	10.32
Annual capital costs of compressor/pump (M€)	6.29	5.74	5.50	5.65
Annual operation and maintenance costs (M€)	1.68	1.53	1.47	1.51
Annual electric power costs (M€/year)	13.29	11.29	10.39	10.93
Annual costs for compression/pumping (M€/year)	21.25	18.56	17.36	18.10

2.3.3 Synthesis Gas Processing

After the according to Ledent (1981) 900 °C hot synthesis gas reaches the surface, it is quenched with water to a temperature below 210 °C and scrubbed to remove trace elements. Subsequently, excessive water is separated and the synthesis gas, a mixture of 35 % N_2, 10 % CO, 21 % H_2, 11 % CH_4 and 23 % CO_2 (cf. Chapter 2.2.1, *Synthesis Gas Composition*) is processed in a gas cleaning section, converting the CO in a gas shift reactor (cf. Figure 2.6). Thereby, sulfur components are removed by physical absorption (Ledent et al., 1981; CEES, 2005). Table 2.8 presents synthesis gas processing CAPEX and OPEX. The latter were modeled using the IECM modeling tool and scaled to the dimensions of the overall UCG-CCGT-CCS process, whereby total variable costs amount to 1.52 M€, total fixed costs up to 4.10 M€ and total capital costs sum up to 132.85 M€.

Table 2.8: OPEX and CAPEX for synthesis gas processing, considering a flow rate of 356,538 sm^3/h, calculation results adapted from Nakaten et al. (2014b).

CAPEX	
Selexol sulfur removal system (€)	13,600,341
Process facilities capital (€)	27,939,551
General facilities capital (€)	4,191,792
Engineer fees (€)	2,793,955
Contingency costs (€)	6,099,105
Interest charges (€)	4,573,254
Royalty fees (€)	139,698
Start-up costs (€)	1,244,049
Inventory (working) capital (€)	205,165
OPEX (variable and fixed costs)	
Selexol solvent (€/year)	69,496
Sulfur by-product credit (€/year)	223,212
Disposal cost (€/year)	428
Electricity (€/year)	1,289,530
Operating labour (€/year)	2,412,349
Maintenance labour (€/year)	344,235
Maintenance material (€/year)	516,443
Admin and support labor (€/year)	826,975

2.3.4 Underground Coal Gasification

All cost positions corresponding to fuel production such as land acquisition, fees, piping, measuring and control equipment, drilling, synthesis gas processing as well as oxidizer compression and injection are integrated within the UCG sub-model. Total drilling meters required for the development of the target areas are determined by the length of the injection and production wells, their deviation length as well as the area extensions (cf. Table 2.9). Thereby, injection and production wells are located outside the UCG exploitation area (cf. Figure 2.4). The deviated drilling length of injection and production wells as well as gasification channels are calculated by the deviation angle and the achievable deviation per drilling meter (cf. Chapter 2.2.4, *Inner Liner and Well Diameters*). The horizontal well length corresponds to the target area extent plus the hole trajectory radius (29 m for injection wells/gasification channels, 87 m for production wells, cf. Chapter 2.2.4, *Inner Liner and Well Diameters*, Table 2.3), since injection and production wells are located outside the UCG exploitation area. The vertical injection and production well length was calculated by the target area depth less the hole trajectory radius.

Table 2.9: Drilling meters required for injection wells, gasification channels and production wells (Nakaten et al., 2014b).

	Seam 1	Seam 2	Seam 3	Seam 4
Deviated drilling length injection wells (m)	90	90	91	90
Vertical drilling length injection wells (m)	3,542	3,176	2,586	2,765
Total drilling length injection wells (m)	3,633	3,267	2,677	2,856
Deviated drilling length gasification channels (m)	1,131	1,356	1,088	724
Horizontal drilling length gasification channels (m)	26,693	23,622	25,625	12,598
Total drilling length gasification channels (m)	27,824	24,978	26,713	13,322
Vertical drilling length production wells (m)	1,713	1,530	1,235	1,325
Deviated drilling length production wells (m)	136	136	136	136
Horizontal drilling length production wells (m)	1,068	787	1,068	787
Total drilling length production wells (m)	2,917	2,454	2,439	2,248
Total drilling meters (m)	34,373	30,698	31,828	18,426

Table 2.10 summarizes all UCG related costs which in total amount to 1.9 bn€. Drilling costs have a 12.4 % share on overall UCG (synthesis gas production) costs. To determine levelized fuel costs, total UCG costs are divided by the fuel consumption during the overall plant operational time (385,280 TJ in 20 years) amounting to 4.95 €/GJ (or 3.9 €/kWh taking into account

Table 2.10: Cost positions related to the UCG process (Nakaten et al., 2014b).

Percentage influence of drilling costs on fuel costs (%)	12.4
CAPEX/OPEX (20 years) of oxidizer production/injection (bn€)	1.1
Permission for utilization/exploration (€)	350
Authorization for utilization/exploration (€)	100
Concession fee for extraction (€)	450
Land acquisition costs (M€)	12.5
Piping, measuring and control equipment (M€)	310.6
Total UCG costs/fuel production costs (plant life time 20 years) (bn€)	1.9

the 2.46 million MWh produced electricity per year and total annual UCG costs of 94.34 m€). In the present study, levelized fuel costs are implemented into the electricity generation sub-model instead of e.g. natural gas costs which would be otherwise considered for fuel costs calculation in conventional power plants. Parameters used for determination of levelized fuel costs are presented in Table 2.11.

Table 2.11: Levelized fuel costs and parameters required for calculation (Nakaten et al., 2014b).

Total UCG costs for a 20 year operational lifetime (bn€)	1.9
Amount of produced synthesis gas (sm^3/h)	356,537
Calorific value synthesis gas (MJ/sm^3)	7.50
UCG plant availability (%)	95
Operational time (h/year)	8,000
Annual fuel consumption CCGT plant (TJ)	19,264
Fuel costs (€/GJ)	4.95

2.3.5 UCG Synthesis Gas Fueled CCGT Power Plant

In order to determine costs for electricity generation in a combined cycle gas turbine (CCGT) power plant considering UCG synthesis gas production and processing costs, the electricity generation sub-model can be applied to determine the costs of electricity (COE) for the overall UCG-CCGT-CCS process. The single computing steps for obtaining the COE were undertaken after Hillebrand (1997), primarily Schneider (1998) (cf. Equations 2.15 to 2.25), and are documented in this chapter. Basic assumptions for the CCGT power plant setup are as follows:

- Electricity production costs are calculated as average costs on a full cost basis.
- The CCGT plant efficiency is 58 %, however due to coupled ASU, CCS and synthesis gas processing, the efficiency decreases by 12 %. According to Schneider (1998); Konstantin (2009); ZEP (2011) and Skorek-Osikowska et al. (2012), CCS causes an efficiency reduction of 5 % to 8 % .
- According to Konstantin (2009), the calculatory interest rate on the planning horizon amounts to 7.5 %.
- A real operating costs annual increase of 1.5 % is assumed.
- An annual CCGT power plant availability of 8,000 operating hours is considered.
- All costs are adapted to the reference year 2012.
- In the current study, the GGCT power plant calculatory fiscal depreciation period is equal to the planning horizon (20 years).

CCGT Plant Investment Costs

Total investment costs (C_I) are calculated from the building owners contribution (C_{IB}), installed net capacity (P_{net}), annual interest payments (C_{aI}) during the construction period and specific investment costs (C_{Is}) (cf. Equation 2.15 and Table 2.12).

$$C_I = C_{Is} \cdot P_{net} + C_{IB} + C_{aI} \tag{2.15}$$

Table 2.12: CCGT power plant investment costs and parameters required for calculation (Nakaten et al., 2014b).

C_{IB}	Building owners contribution (k€)	70
C_{Is}	Specific investment costs (€/kW$_{el}$)	469
P_{net}	Installed power plant capacity (MW$_{el}$)	308
C_{aI}	Annual interest payments for construction period (k€)	39
C_I	Power plant investment costs (k€)	144,420

Specific investment costs are index numbers of the invested capital aiming at the production of one MWh electricity. The building owners contribution amounts to 15 % of the total investment costs and comprises the costs of power plant construction, land acquisition, infrastructure, construction of auxiliary facilities, charges for approval procedures, as well as commissioning and provision of working capital and are covered by the building owners. The annual interest payments rely on the duration of the construction period, the payment profile and the interest rate. All costs will incur after half of the construction period (Schneider, 1998). Annual capital costs (C_{aC}) are calculated from the annual interest payment and the amount of depreciation, whereby all power plants have an uniform tax write off period. For the present simulations, a linear depreciation model was assumed. Regarding the reversionary interest payment, the first payment matures with the first write off. Alternatively, the annual interest payment (C_{aI}) is calculated from the unamortized investment amount. The constant annual depreciation costs (C_{aD}) are calculated according to Equation 2.16 and the annual interest payment is calculated from Equation 2.17, whereby both Equations are adapted from Schneider (1998). Cost items and parameters required to calculate annual capital costs are presented in Table 2.13.

$$C_{aD} = \frac{C_{aC}}{n_A} \tag{2.16}$$

$$C_{aC} = C_I \cdot R_i - ((O_y - 1) \cdot C_{aD}) \cdot R_i \tag{2.17}$$

Table 2.13: Annual capital CCGT power plant costs and values required for calculation (cf. Equation 2.17), data from Nakaten et al. (2014b).

C_{aD}	Constant annual depreciation costs (k€)	4,814
C_I	CCGT power plant investment costs (k€)	144,420
R_i	Nominal interest rate during construction (%)	8.3
O_y	Observation year n (year)	1
n_A	Imputed fiscal depreciation period (years)	20
C_{aC}	Annual capital costs (k€)	163,179

CCGT Plant Operational Costs

Operational costs are a result of operational processes and comprise fixed and variable operational costs. Due to inflation and collective bargaining, increasing operational costs were taken into account for COE computation. In the current study, cost positions such as taxes and insurances, service and maintenance costs (C_M) as well as personnel costs belong to the fixed operational costs (C_{fO}) which are calculated according to Equation 2.18 (cf. Table 2.14). Total personnel costs (C_P) arise from the number of employees and personnel-specific costs. The CCGT power plant's tax burden is linked to its profit position.

$$C_{fO} = C_P + C_M + C_{aTI} \cdot C_{Is} \cdot P_{net} \tag{2.18}$$

Table 2.14: Cost items to determine CCGT power plant fixed operating costs according to Equation 2.18 (Schneider, 1998), data from Nakaten et al. (2014b).

C_P	Personnel costs (k€/year)	1,484
C_{aTI}	Annual tax and insurance burden (%)	5.5
C_M	Operational and maintenance costs (k€/year)	2,953
C_{Is}	Specific investment costs (€/kW$_{el}$)	469
C_{fO}	Fixed operating costs (k€/year)	5,230

Variable annual operating costs amount to 28.86 M€ and are a product of the produced electricity (E_p) and the specific operational costs for every single reference year (1.17 €/MWh). Taking into account 8,000 annual full load hours (H_{fl}) and an installed capacity (P_{net}) of 308 MW$_{el}$, the annual produced electricity amounts to 2,462 GWh (cf. Equation 2.19). According to Equation 2.20, variable and fixed operating costs are summated to the total annual operating costs (C_{OP}), whereby Table 2.15 enlists the related parameters.

$$E_p = H_{fl} \cdot P_{net} \tag{2.19}$$

$$C_{OP} = C_{fO} + C_{vO} \tag{2.20}$$

Table 2.15: CCGT power plant annual OPEX according to cf. Equation 2.20 (Schneider, 1998) and parameters used for calculation, data from Nakaten et al. (2014b).

C_{fO}	Fixed operating costs (k€/year)	5,230
C_{vO}	Variable operating costs (k€/year)	2,886
C_{OP}	Total annual operating costs (k€/year)	8,116

Capital Value of the Overall Costs

The capital value of the overall costs (C_{Cvo}) is the total worth of the entire investments (cf. Equation 2.21). Table 2.16 presents cost items and parameters for determination of this cost position.

$$C_{Cov} = \sum_{n=1}^{n_p} \frac{C_{CvaC}}{(1+i_r)^n} + \sum_{n=1}^{n_p} \frac{C_{CvaF}}{(1+i_r)^n} + \sum_{n=1}^{n_p} \frac{C_{CvaO}}{(1+i_r)^n} \tag{2.21}$$

Table 2.16: Parameters to calculate the capital value of the overall costs by using Equation 2.21 (Schneider, 1998), data from Nakaten et al. (2014b).

n	Years of operation	20
n_p	Planning horizon (years)	20
i_r	Nominal interest rate on planning horizon (%)	7.5
C_{CvaO}	Capital value annual operating costs (k€)	82,739
C_{CvaF}	Capital value annual fuel costs (k€)	971,930
C_{CvaC}	Capital value annual capital costs (k€)	163,179
C_{Cvo}	Capital value of the overall costs (k€)	1,217,847

Levelized Total Annual Costs With and Without Demolition

Demolition and restoration costs after a power plant operational lifetime of 20 years significantly depend on the interest payment. According to Schneider (1998) the assumed nominal imputed interest rate for restoration and demolition (i_{rDC}) in the present study is 6 %. Demolition costs (C_D) amount to 4,984 €, being multiplied by the installed CCGT power plant capacity (308 MW_{el}) and the specific demolition cost (16 €/kWh). The levelized annual costs of restoration and demolition (C_{aRD}) are determined by Equation 2.22 presented in Schneider (1998) and sum up to 63 €. Thereby, the annual costs of restoration and demolition are levelized at the end of the operating time and discounted to the calculatory fiscal depreciation period (n_A) of 20 years to the year of commissioning. Applying Equation 2.23 adapted from Schneider (1998), the levelized total annual costs without demolition (C_{awD}) account to 119,461 €. The levelized total annual costs (C_{aLT}) amount to 119,524 € by summing up the levelized total annual costs without demolition and the levelized annual costs of restoration and demolition according to cf. Equation 2.24 (Schneider, 1998).

$$C_{aRD} = \sum_{n=1}^{n} \frac{C_D}{(1+i_{rDC})^{n_A}} \cdot \frac{i_r(1+i_{rDC})^{n_A}}{(1+i_{rDC})^{n_A}-1} \tag{2.22}$$

$$C_{awD} = C_{Cvo} \frac{i_r(1+i_r)^{n_p}}{(1+i_r)^{n_p}-1} \tag{2.23}$$

$$C_{aTI} = C_{awD} + C_{aRD} \tag{2.24}$$

COE Determination

According to Equation 2.25 adapted from (Schneider, 1998), total costs of electricity are calculated from the levelized total annual costs and the amount of produced electricity. Thereby, COE are the costs which occur for energy conversion into electrical power, usually quoted in € per MWh. In the present study COE amount to 48.56 €/MWh.

$$COE = \frac{C_{aLT}}{E_p} \tag{2.25}$$

2.3.6 Carbon Capture and Storage

Differing cost estimates presented in various CCS studies usually result from differences in technology performance assumptions, input costs or the methodology used to convert the inputs into levelized costs (GCCSI, 2011). Furthermore, costs can vary significantly because of location-specific factors such as labor rates, fuel costs, fuel characteristics, and the geology of the selected storage formation. According to GCCSI (2011), the impact of storage costs on CCS costs contributes less than 5 % under ideal conditions, increasing to around 10 % for storage sites with „poorer“ geologic boundary conditions. The highest cost uncertainty in large-scale demonstration plants is represented by the up-front capital costs, since incorporating CCS increases capital investment costs by about 30 % for IGCC power plants and by 80 % to even 100 % for coal and gas power plants (GCCSI, 2011). Taking this high volatility in plant construction costs into account, real project costs are difficult to gauge. As a result of changing methodologies and the inclusion of previously omitted aspects, CCS costs are lately suggested to be 15 % to 30 % higher than previous estimates (GCCSI, 2011). CCS costs in the present study were calculated applying the IECM tool by CEES (2005) to determine capture costs and the model after McCollum and Ogden (2006), which in due consideration of various side-specific input parameters allows for individual cost calculation of CO_2 compression, injection, and storage. CCS costs generally consist of CO_2 separation, transportation, compression and injection as well as storage and monitoring costs. Transportation costs are neglected in the present study, since the separated CO_2 is stored in-situ in the UCG voids.

CO_2 Capture

Considering the post-combustion Monoethanolamine (MEA) CO_2 capture technology, capture costs were modeled via the IECM tool and rescaled to the dimensions of the UCG-CCGT-

CCS process. Capital costs for the MEA plant amount to 134.30 M€ and capital costs for the process facilities to 88.64 M€, whereby total fixed costs account to 4 M€ and variable costs to 6.78 M€. Under consideration of the cost input data mentioned and the captured CO_2 amount (63.25 t/hour), levelized MEA costs add up to 9 €/t CO_2 (cf. Table 2.17).

CO_2 Compression and Injection

In dependence of the storage capacity available in the former UCG voids (20.5 %, cf. Chapter 2.2.2, *CO_2 Emission Handling Strategy*) a CO_2 amount of 1,518 t/day (resulting from UCG and power generation) is separated, cooled down and compressed from atmospheric pressure to the pressure determined for injection. The power required for CO_2 compression and injection was evaluated according to Equations 2.11 to 2.14 adapted and modified from McCollum and Ogden (2006), also utilized for oxidizer compression- and injection cost calculation. As well as for oxidizer compression, five compressor stages were applied to achieve the compression level required for CO_2 injection. Since CO_2 compressibility (Z_s) and the ratio of specific heat (k_s) are different at each stage, the compressor power requirement calculation (cf. Equation 2.11) was undertaken for each stage separately using EOS by Kunz and Wagner (2012). Table 2.18 presents the bandwidth of CO_2 compressibility and specific heat in the different stages as well as the total compression power requirement summing up to 5.23 MW to 5.35 MW. The bandwidth of total compression power requirement is caused by the different coal CV_{Coal} of the respective target coal seams. As their coal calorific values vary between 33.16 MJ/kg and 35.58 MJ/kg (cf. Table 2.2), the daily coal consumption to supply the CCGT power plant varies as well (2,870 t/day to 3,100 t/day), resulting in different amounts of produced CO_2, hence different CO_2 mass flow rates (cf. Table 2.19) through the compressor train. The maximum size of one compressor train is 40,000 kW (McCollum and Ogden, 2006).

Table 2.17: MEA process OPEX and CAPEX considering a CO_2 mass flow rate of 63.25 t/hour, data from Nakaten et al. (2014b).

CAPEX (MEA total process facilities capital, MEA scrubber process costs)	
Direct contact cooler (€)	13,967,615
Flue gas blower (€)	2,562,839
CO_2 absorber vessel (€)	36,219,153
Heat exchangers (€)	1,505,488
Circulation pumps (€)	3,101,294
Sorbent regenerator (€)	11,361,631
Reboiler (€)	5,580,718
Steam extractor (€)	709,886
Sorbent reclaimer (€)	249,726
Sorbent processing (€)	423,861
Drying and compression unit (€)	12,955,136
CAPEX (MEA total capital requirement, MEA plant costs)	
Process facilities capital (€)	88,649,485
General facilities capital (€)	8,864,949
Engineer fees (€)	6,207,190
Contingency costs (€)	17,726,445
Interest charges (€)	8,813,174
Royalty fees (€)	443,190
Start-up costs (€)	2,981,637
Inventory (working) capital (€)	606,912
OPEX (variable and fixed costs)	
Sorbent (€/year)	174,538
Activated carbon (€/year)	120,347
Caustic solution (NaOH) (€/year)	43,076
Reclaimer waste disposal (€/year)	35,926
Electricity (€/year)	6,264,717
Water (€/year)	143,185
Operating labour (€/year)	461,771
Maintenance labour (€/year)	1,214,400
Maintenance material (€/year)	1,821,313
Admin and support labor (€/year)	502,846
Total averaged levelized MEA costs (€/t CO_2)	8.88

Table 2.18: CO_2 compression power consumption according to Equation 2.11 (McCollum and Ogden, 2006) and the required cost items for calculation, data from Nakaten et al. (2014b).

CR	Optimal compression ratio of each stage (-)	2.36
M	Molecular weight of CO_2 (kg/mol)	44.01
m	Mass flow rate CO_2 (t/day)	1,518
Z_s	Average CO_2 compressibility for each compressor stage (-)	0.71 - 0.99
k_s	Average ratio of specific CO_2 heat for each individual stage (-)	1.29 - 2.50
$W_{s,i}$	Total compression power requirement (MW)	5.23 - 5.35

In case that the required total compression power is above that value, the CO_2 flow rate must be split into parallel compressor trains. Equation 2.12 (cf. Table 2.19) is applied to determine the power requirement for pumping (W_p). Since capital costs for the pumps are already considered in the context of the oxidizer compression and injection sub-model (cf. Table 2.7), CAPEX for pumps are not taken into account a second time at this point. The density values listed in Table 2.19 represent the CO_2 condition during pumping. The varying pumping power consumption (175 kW to 218 kW) is related to the different target coal seam depths, hence different well head pressures during injection. The annual costs for CO_2 compression and injection are presented in Table 2.20.

Table 2.19: CO_2 pumping power requirement according to Equation 2.12 and cost items required for determination, data from Nakaten et al. (2014b).

		Seam 1	Seam 2	Seam 3	Seam 4
m	CO_2 mass flow rate (t/day)	1,526	1,494	1,526	1,526
N_t	Number of parallel compressor trains (-)	1	1	1	1
p_{in}	Compressor inlet pressure (MPa)	0.1	0.1	0.1	0.1
p_{WHP}	Well head pressure (MPa)	7.86	7.19	6.33	6.58
p_{BHP}	Bottom hole pressure (MPa)	18.00	16.17	13.22	14.11
T	Temperature (°C)	37.69	32.80	24.92	27.31
p_{co}	Critical pressure CO_2 (MPa)	7.38	7.38	7.38	7.38
ρ	CO_2 density (kg/sm^3)	867	858	845	849
η	Pump efficiency (-)	0.75	0.75	0.75	0.75
W_p	Required power for the pumps (kW)	218	195	175	182

Table 2.20: Annual costs for CO_2 compression and injection, data from Nakaten et al. (2014b).

	Seam 1	Seam 2	Seam 3	Seam 4
Total capital costs for compressor (€)	1,721,640	1,801,653	1,720,929	1,720,929
Annual capital costs of compressor (€)	258,246	270,248	258,139	258,139
Annual operational/maintenance costs (€)	68,866	72,066	68,837	68,837
Annual electric power costs (€/year)	2,315,252	2,258,286	2,297,481	2,300,483
Annual compression/pumping costs (€/year)	2,642,364	2,600,600	2,624,457	2,627,459

CO_2 Storage

In the present study it is assumed that all injection wells are dually used for oxidizer and CO_2 injection as well as for synthesis gas production. Therefore, additional costs for special corrosion resistant tubing have to be taken into account. Costs for the injection equipment include supply wells, distribution lines, well heads, electrical services, etc. Table 2.21 lists the calculation results for CO_2 storage costs.

Table 2.21: Costs for CO_2 storage, data from Nakaten et al. (2014b).

	Seam 1	Seam 2	Seam 3	Seam 4
Total operation and maintenance costs (€/year)	72,261	71,025	70,041	70,457
Total annual costs (€/year)	267,497	266,261	265,277	265,693
Levelized costs of CO_2 storage (€/t CO_2)	0.60	0.61	0.60	0.60

2.3.7 Total UCG-CCGT-CCS Costs

Taking into account that according to the determined volumetric storage capacity in former UCG voids only 20.5 % of the produced CO_2 is captured and stored (cf. Chapter 2.2.2, *CO_2 Emission Handling Strategy*), CCS costs sum up to 15.32 €/MWh (Seam 3) to 15.58 €/MWh (Seam 2). Table 2.22 shows the levelized costs for CO_2 capture (8.8 €/t CO_2 to 9.0 €/t CO_2), CO_2 compression/pumping (6.48 €/t CO_2 to 6.57 €/t CO_2) and storage (0.60 €/t CO_2 to 0.61 €/t CO_2). Total levelized CCS costs taking into account CO_2 compression, pumping and storage costs for 20.5 % captured CO_2 (without CO_2 emission charges) amount between 15.32 €/t CO_2 and 15.58 €/t CO_2. The varying CCS costs presented in Table 2.22 result from different coal CV_{Coal} of the respective target coal seams, hence different required coal amounts resulting in slightly differing amounts of produced CO_2. Summing up average COE (48.56 €/MWh) and average

Table 2.22: CO_2 emission handling costs as part of the UCG-CCGT-CCS process setup (Nakaten et al., 2014b).

	Seam 1	Seam 2	Seam 3	Seam 4
Levelized CO_2 capture costs (€/t CO_2)	8.8	9.0	8.8	8.8
Levelized compression/pumping costs (€/t CO_2)	6.53	6.57	6.48	6.49
Levelized costs of CO_2 storage (€/t CO_2)	0.60	0.61	0.60	0.60
Levelized costs for CO_2 emission handling (20.5 % CCS, no emission charges) (€/t CO_2)	15.37	15.58	15.32	15.33
COE (€/MWh)	48.56	48.56	48.56	48.56
COE with 20.5 % CCS and CO_2 emission charges (€/MWh)	71.67	71.67	71.67	71.67
COE with no CCS but 100 % CO_2 emission charges (€/MWh)	73.64	73.64	73.64	73.64

CCS costs (15.45 €/MWh), COE with CCS costs amount to 71.67 €/MWh. Average COE without CCS costs but CO_2 emission charges add up to 73.64 €/MWh.

2.4 Discussion

According to the objective of this thesis to investigate site specific cost effectiveness of a coupled UCG-CCGT-CCS system, a flexible scalable techno-economic model was developed. The model is applicable for UCG-CCGT-CCS COE determination for any target area world wide. However, in the present study UCG-CCGT-CCS COE quantification is exemplified for a selected target area in Northeast Bulgaria.

In order to determine COE, this methodological and interdisciplinary approach of combining geological, engineering and economic analyses was chosen as efficiency and success of a coupled UCG-CCGT-CCS system are determined by a complex interaction of boundary conditions. Site-specific geological data determining the boundary conditions for the techno-economic model setup were adapted from scientific research results elaborated in the context of the UCG&CO_2STORAGE project. Technical model input parameters, such as the surface infrastructure setting (e.g. compressors, pumps, etc.) and UCG-related processes (e.g. piping, measuring, control equipment, etc.) were adapted from literature (Franke and Beckervordersandforth, 1978; Ledent, 1981; Ledent et al., 1981; Hewing et al., 1988; Schneider, 1998;

McCollum and Ogden, 2006; Ramezan et al., 2007; Konstantin, 2009), and expert interviews (Green, 2011; Lösch, 2013). Comparing the results of UCG-CCGT-CCS COE determination (71.67 €/MWh) with according to ZEP (2011) averaged European CCGT-CCS COE summing up to 105 €/MWh, the commercial-scale scenario for the Bulgarian target area elaborated in the present study reveals to be an economic option for low carbon electricity production.

Knowledge on possible COE variation bandwidths related to uncertainties due to e.g. lack of data or changing boundary conditions is important, particularly with regard to a potential UCG-CCGT-CCS implementation. In order to quantify the impact geological, chemical, technical and market-dependent data uncertainties may have on COE, sensitivity analyses on UCG-CCGT-CCS economics are applied. The results are discussed in Chapter 3, *Uncertainty Assessment of Site Specific Model Constraints*.

To determine UCG-CCGT-CCS economics in a more comprehensive way, local commercial-scale scenarios such as the one developed in this chapter, have to be incorporated into the context of the entire national energy system. This is because besides site-specific UCG boundary conditions, an economic UCG-CCGT-CCS application also depends on e.g. the resource availability, the overall power generation system (power plant age, energy mix), and the national transmission line infrastructure. This issue is addressed in Chapter 4 (*UCG-CCGT-CCS Implementation*).

Another issue, that was not part of the present study but became evident during the model development is, that surface process chains (example given synthesis gas processing and the ASU process) may be optimized by thermodynamic modeling of the process design considering heat and energy utilization.

3 Uncertainty Assessment of Site Specific Model Constraints

In order to further assess COE as a result of the model input parameter variability considering geological, chemical, technical and market-dependent model constraints, Chapter 3 shows the results of one-at-a-time (OAT) and multivariate sensitivity analyses carried out to investigate the impact of 14 model input parameters. Hereby, the assortment relates to parameters which are known to have a relevant impact on UCG-CCGT-CCS COE, to those which were aligned with high uncertainty due to lack of literature and cost data and to parameters with low uncertainty (e.g. geological parameters) since the target area is well explored. As it is the case in this thesis, due to lack of data surface infrastructure cost data (ASU process, synthesis gas processing) had to be scaled linearly to the dimensions of the overall process setup. A large part of the sensitivity analysis results recline on Nakaten et al. (2014a).

3.1 One-at-a-Time Sensitivity Analysis

The one-at-a-time sensitivity analysis was carried out to investigate

- geological (coal seam thickness, depth, extent, seam thickness to cavity width ratio, daily progress of the gasification front, coal CV_{Coal}),
- chemical (synthesis gas composition),
- technical (UCG and CCGT annual operating hours, CCGT power plant efficiency),
- and market-dependent model input parameters (average drilling costs, synthesis gas processing costs, nominal interest rate of the CCGT plant, oxidizer production and injection costs, CO_2 emission charges).

Values that were expected to decrease COE compared to the reference scenario are appointed as best-case scenarios and values probably causing a COE increase are defined as worst-case scenarios, respectively. These scenarios are based on project and literature data as well as expert interviews, whereby the investigation bandwidth for each selected parameter was deduced in accordance to data availability and the respective expected level of uncertainty. The reference scenario represents the commercial-scale scenario discussed in Chapter 2, *Techno-Economic Model for UCG-CCGT-CCS COE Determination*. Table 3.1 lists the selected model input parameters and their defined variation bandwidths in the reference, best- and worst-case scenarios. Listed oxidizer production costs also comprise oxidizer compression and injection.

Table 3.1: Deduced variation bandwidths of the analyzed model input parameters in the worst-, best-case and the reference scenario.

	Worst-case	Reference scenario	Best-case
Average seam thickness (m)	-10 %	8.4	+10 %
Average seam depth (m)	-10 %	1,538	+10 %
Seam extents, both target areas (km^2)	-10 %	1.14/0.62	+10 %
Seam thickness to cavity width ratio (-)	1:2	1:2	1:10
Daily progress gasification front (m/day)	1	3	5
Coal calorific value (kg/MJ)	-10 %	34.1	+10 %
Synthesis gas composition	CO_2-rich	-	CH_4-rich
Annual operating hours UCG/CCGT (h)	6,000	8,000	8,322
CCGT power plant efficiency (%)	30	46	48
Averaged drilling costs (€/m)	-25 %	1,915	+25 %
Synthesis gas processing OPEX (M€)	-25 %	113.7	+25 %
Synthesis gas processing CAPEX (M€)	-25 %	132.9	+25 %
Nominal interest rate CCGT plant (%)	9	7.5	3
Oxidizer production costs (bn€)	-25 %	1.1	+25 %
CO_2 emission charges (€/t CO_2)	50	25	6

In the present study model input parameters were determined conservatively, especially those aligned with high uncertainty due to lack of data (±25 % compared to the reference scenario). Geological model input variables (coal calorific value, seam extent, thickness and depth) have a variability of ±10 % compared to the reference scenario, since the study area is well explored.

Furthermore, geological parameters are related primarily to drilling costs. Since drilling costs are far below other UCG fuel cost positions in the present study, COE sensitivity to geological parameters is low. Taking into account a variability below 10 % is not reasonable, since this would decrease COE sensitivity to these variables, resulting in insignificant COE changes. Assuming a higher variability e.g. for the parameters coal CV_{Coal}, seam thickness and extent, coal resources would not be sufficient to provide the required coal supply for the CCGT power plant in the worst-case scenarios.

3.1.1 Geological Model Boundary Conditions

In the present study, the investigated geological model input parameters are the coal seam depth, thickness, extent, daily progress of the gasification front, seam thickness to cavity width ratio and the coal calorific value.

Coal Seam Thickness

In the reference scenario the average coal seam thickness of all considered target coal seams is 8 m (cf. Chapter 2.2.3, *Pressure Loss Calculation for Injection and Production Wells*, Table 2.2) and was varied by ±10 % to 7.2 m in the worst- and to 8.8 m in the best-case scenarios (range resulting from geological surveys). Taking into account a higher variability, resources in the worst-case scenario would not be sufficient to provide the required coal for synthesis gas production to fuel the CCGT power plant. The economic advantage of thick coal seams is a higher coal yield per injection well resulting in decreased drilling costs, as less wells are required to achieve equal outputs. Thus, varying coal seam thickness by ±10 % compared to the reference scenario, sensitivity analysis results point out a COE increase and decrease by ±0.2 % (cf. Figure 3.1) caused by changing drilling costs. Nevertheless, drilling costs in the current study do not have a significant impact on COE, since drilling costs are far below other fuel cost positions or costs for power generation (cf. Figure 3.2). Besides, the drilling infrastructure was optimized by developing a drilling cost saving setup. Therefore, COE do not reveal a high sensitivity to coal seam thickness. Figure 3.2 depicts the percentage influence of fuel and power plant costs on COE under consideration of different coal seam thicknesses.

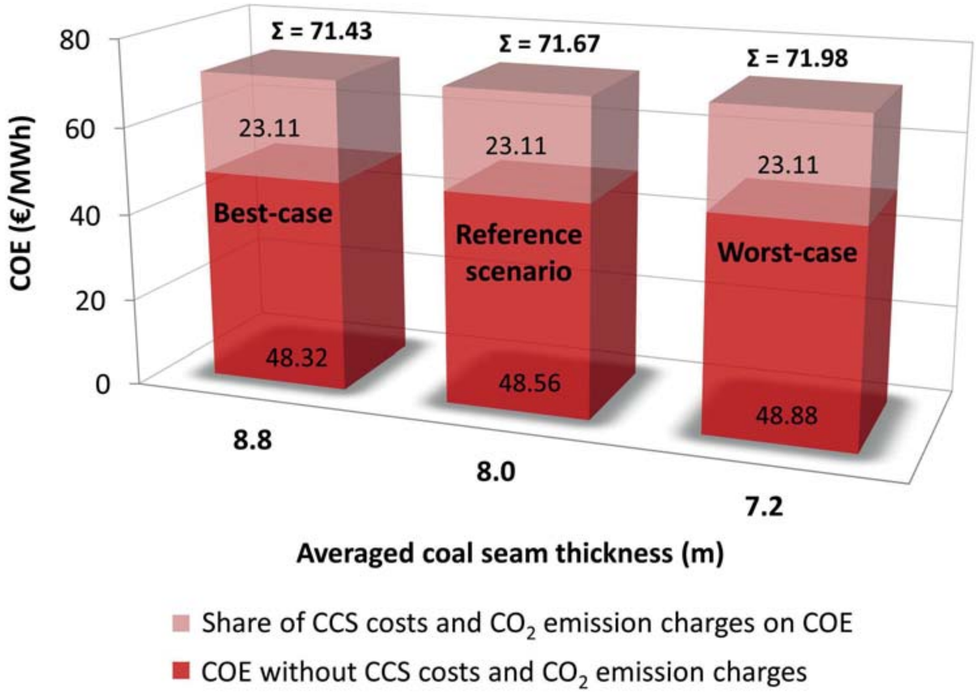

Figure 3.1: Coal seam thickness variation between 7.2 m to 8.8 m results in an overall COE difference of 0.6 €/MWh, including CO_2 emission handling costs.

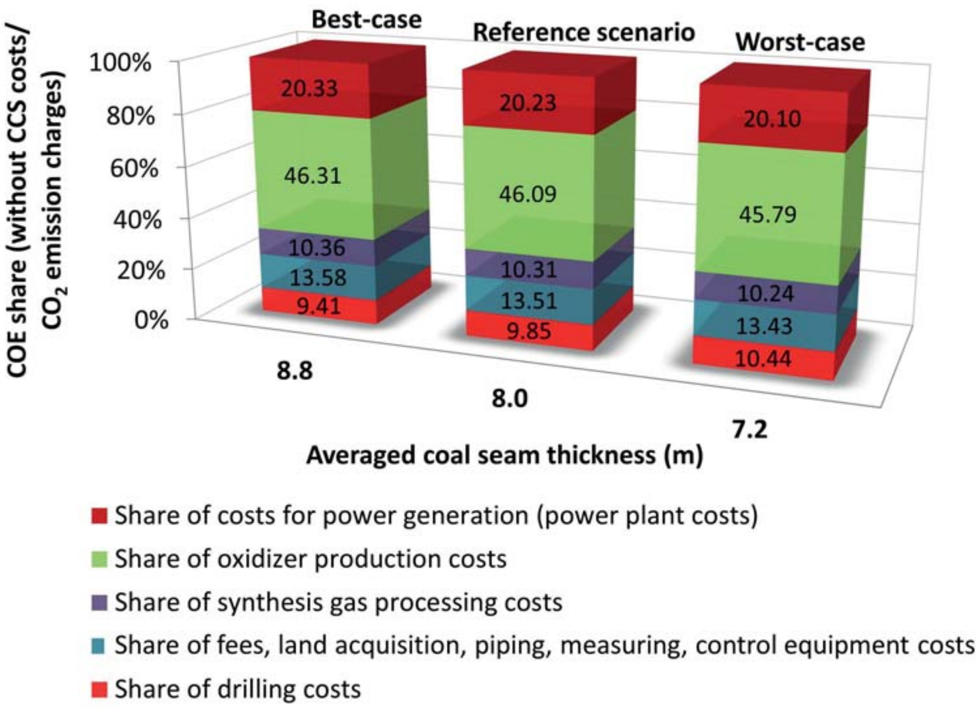

Figure 3.2: Coal seam thicknesses variation by ±10 % compared to the reference scenario and the resulting percentage impact of fuel and power plant costs on COE (without CCS costs or CO_2 emission charges).

Coal Seam Depth

The average coal seam depth in the reference scenario amounts to 1,561 m (cf. Chapter 2.2.3, *Pressure Loss Calculation for Injection and Production Wells*, Table 2.2). Varying seam depth by ±10 % to 1,405 m in the best-case and to 1,717 m in the worst-case (compared to the reference scenario), covers a representative bandwidth of coal seam depths in the target area. With regard to target areas not that well explored via drilling, various geophysical methods (e.g. reflection seismics) provide the option to localize coal seams. Hence, the parameter coal seam depth is generally related with a relatively low uncertainty. Sensitivity analysis results illustrated in Figure 3.3 show that a variation of seam depth by ±10 % compared to the reference scenario causes COE differences of up to ±0.4 %. Figure 3.4 shows the impact of fuel costs and other power plant costs on COE when seam depth is varied.

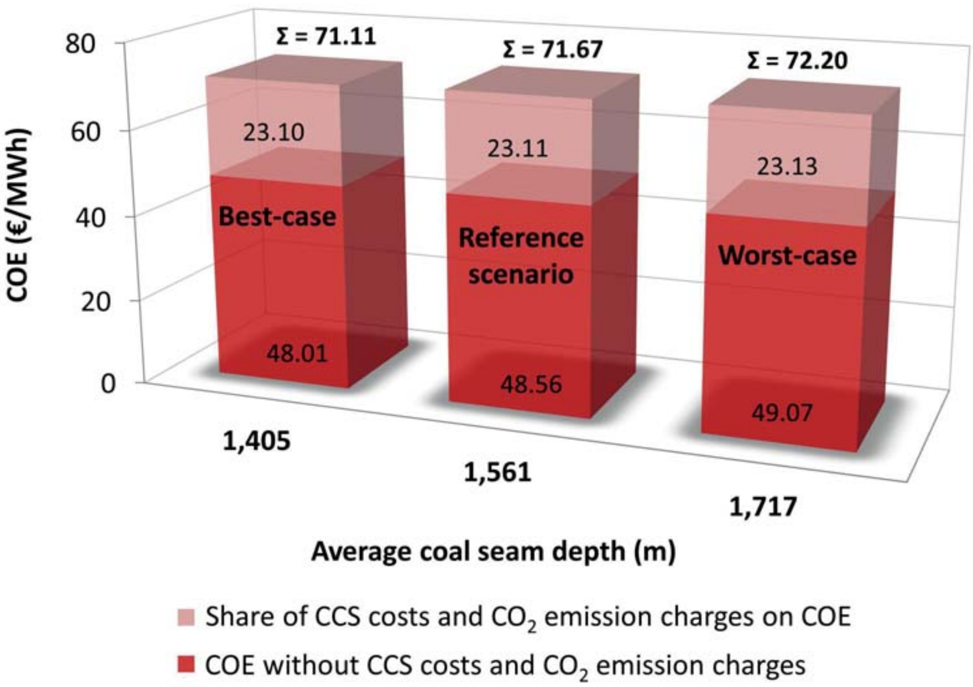

Figure 3.3: Coal seam depth variation from 1,405 m to 1,717 m causes an overall COE difference of 1.1 €/MWh, including CO_2 emission handling costs.

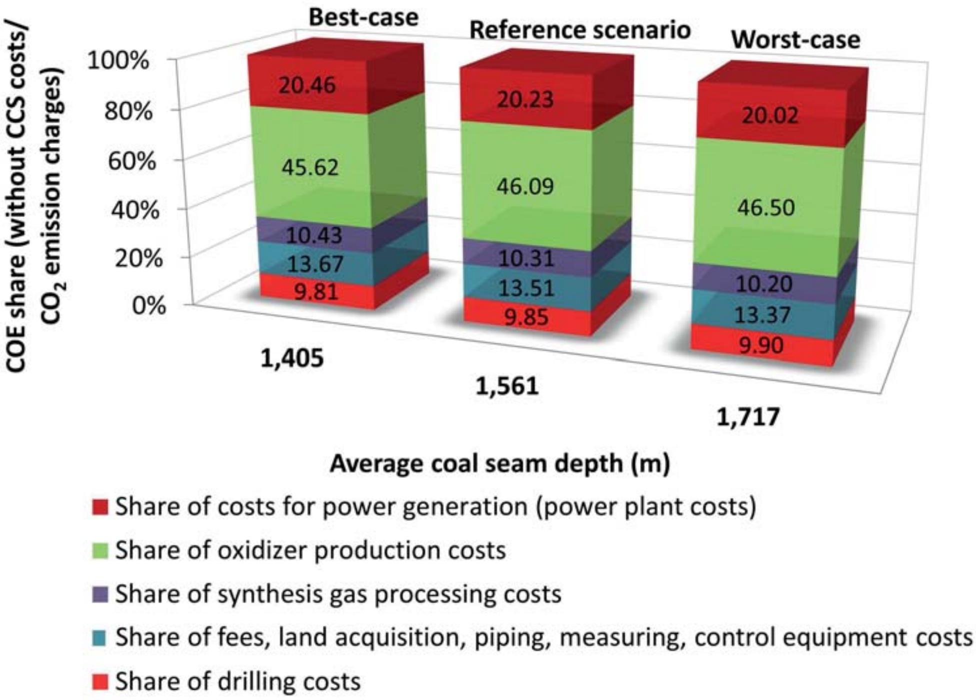

Figure 3.4: Coal seam depth variation by ±10 % compared to the reference scenario and the resulting percentage impact of fuel and power plant costs on costs of electricity (without CCS costs or CO_2 emission charges).

Coal Seam Extent

In the reference scenario, the selected target area extents amount to 0.88 km^2 in average (cf. Chapter 2.2.3, *Pressure Loss Calculation for Injection and Production Wells*, Table 2.2) and vary by ±10 % in the worst- and best-case scenarios (cf. Figures 3.5 and 3.6). A higher variability was not chosen, since coal resources would not be sufficient to supply the CCGT power plant in the worst-case scenario. Furthermore, increasing the UCG area extent by considering a higher variability, the safety distance to the surrounding faults will be insufficient in this specific case. Figure 3.5 shows that taking into account 10 % smaller seam extents (1.03 km^2 and 0.56 km^2), fuel costs and hence overall COE decrease by 0.8 % compared to the reference scenario, as the drilling infrastructure is adjusted to the according coal seam dimension. Coal supply in this scenario is sufficient for 19.7 years, only.

Extending seam latitudes to 1.25 km^2 and 0.68 km^2, COE increase by 1 %, since the well layout is dynamically adjusted to the larger area. The target area extension increases available coal resources for UCG by additional 270 t/day, and in case coal resources would be exploited completely (as well as in the reference scenario a coal reserve for 1.5 years was retained) even longer. According to that increased coal supply, the installed power plant net capacity could be raised. However, to keep a basis for comparison to the other scenarios, the installed power plant net capacity was maintained constant.

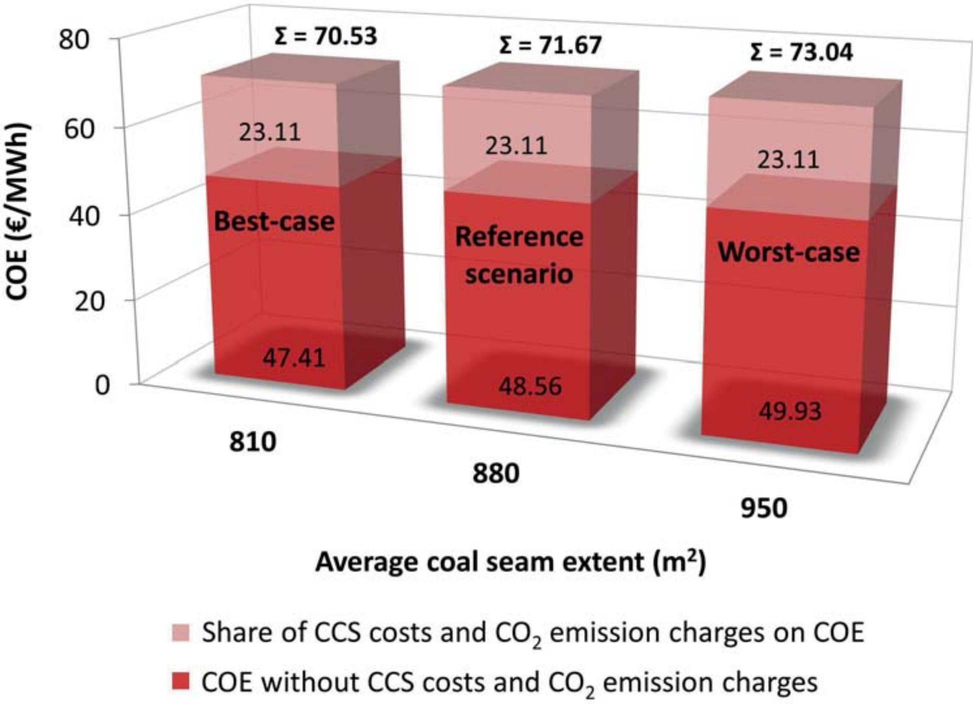

Figure 3.5: Coal seam extent variation from 810 m^2 to 950 m^2 results in overall COE differences of 2.5 €/MWh, including CO_2 emission handling costs.

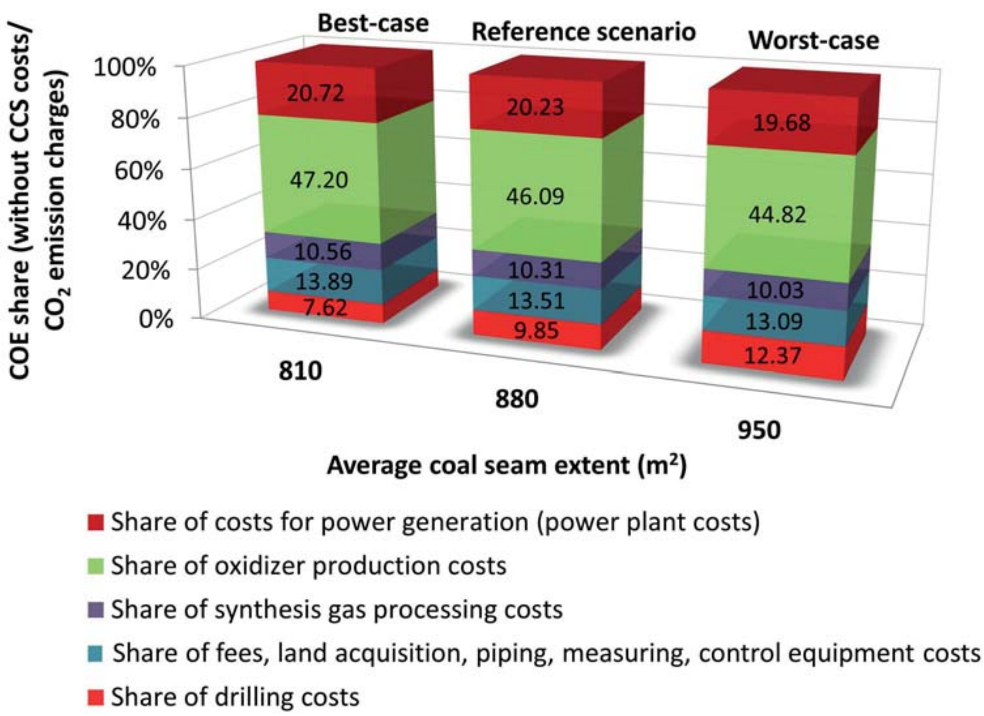

Figure 3.6: Variation of coal seam extent by ±10 % compared to the reference scenario and the resulting percentage influence of fuel and power plant costs on costs of electricity, without CCS costs or CO_2 emission charges.

In summary, varying the coal seam extent by ±10 % causes a COE margin of 2.5 €/MWh. The percentage influence of fuel costs and other power plant costs on COE considering varying seam extents is illustrated in Figure 3.6 and shows that drilling costs increase in line with thinner coal seams. This is because according to Luo et al. (2009) the ratio of the distance between the gasification channels and the seam thickness is 2:1, resulting in a higher number of gasification channels required for coal seam exploitation and thus in higher drilling costs.

Seam Thickness to Cavity Width Ratio

Model input parameters in the present study were generally defined conservatively, especially variables with high uncertainty such as the seam thickness to cavity width ratio. For the reference scenario, a seam thickness to cavity width ratio of 1:2 was taken into account (cf. Chapter 2.2.4, *Well Layout and Diameters*). Since according to Sheng et al. (2013) this ratio was found to be stable, no smaller ratios were considered. Thus, the seam thickness to cavity width ratio of 1:2 also represents the worst-case scenario in the present study. In order to consider the high uncertainty of this parameter, the seam thickness to cavity width ratio was increased considerably to 1:10 in the best-case scenario. The advantage of large-scale cavities is, that they allow for higher coal yields than smaller ones, e.g. in the best-case scenario the coal yield is 86 %, whereby in the worst-case and in the reference scenario the coal yield amounts to 46 %. Indeed, according to Sarhosis et al. (2013) a larger scaling decreases the geomechanical cavity stability. Figure 3.7 illustrates a COE margin of 4 €/MWh (3 %) comparing the best- and worst-case scenarios. However, for a practical implementation, this COE margin caused by uncertainty regarding seam thickness to cavity width ratios is low compared to the previous challenge to scale the overall process infrastructure. Taking into account the best-case scenario and a daily gasification front progress of 3 m, the resources provided by the two thickest coal seams completely cover the coal demand for power generation. Hence, the development of the two thinner coal seams was neglected. With regard to a seam thickness to cavity width ratio of 1:3, exploitation of the thinnest coal seam is not required. The percentage impact of fuel and power plant costs on overall COE under influence of varying seam thickness to cavity width ratios of 1:2 to 1:10 is shown in Figure 3.8. In line with a larger cavity width, less gasification channels have to be drilled for coal seam development. Besides, exploitation of the thinnest coal seam can be neglected resulting in decreased drilling costs (cf. Figure 3.8). However, as drilling costs are much lower than the other fuel and power plant costs, their impact on COE is relatively low. Overall UCG fuel costs in the best-case scenario decrease by 7.8 % compared to the worst-case scenario. As UCG fuel costs have a significant COE impact (up to 80 %), the share of power plant costs decreases simultaneously. Oxidizer production and synthesis gas processing CAPEX are scaled to the power plant capacity and operating hours which remain constant in the different scenarios. Hence, their percentage influence on COE does not vary significantly in the underlying scenarios.

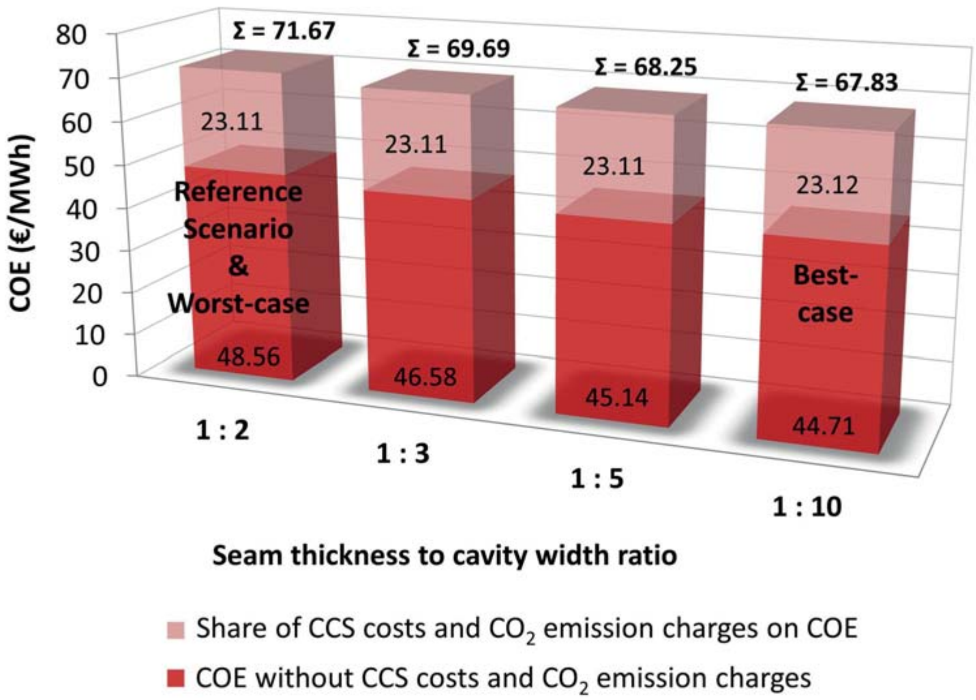

Figure 3.7: Coal seam thickness to cavity width ratio variation from 1:2 to 1:10 causes a COE, margin of 3.8 €/MWh (including CO_2 emission handling costs), modified from Nakaten et al. (2014a).

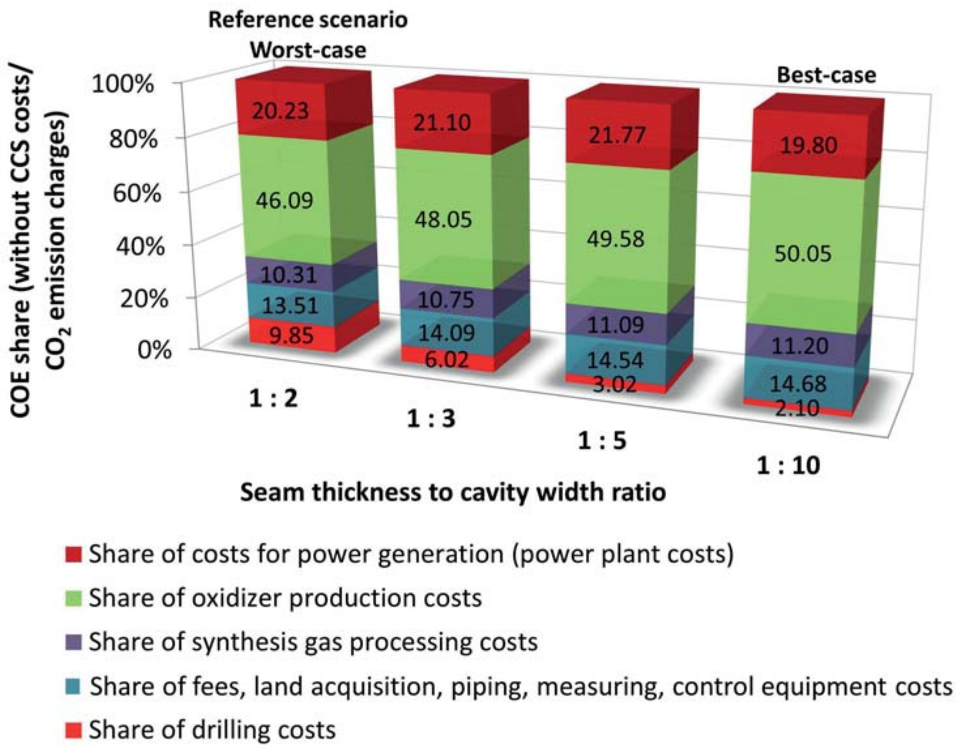

Figure 3.8: Coal seam thickness to cavity width ratios from 1:2 to 1:10 and the resulting percentage impact of fuel and power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

Daily Horizontal Progress of the Gasification Front

According to Luo et al. (2009), cavity growth directly impacts coal resource recovery and energy efficiency and therefore UCG economic feasibility. Thus, another parameter of interest examined in the context of this thesis was, how the horizontal daily progress of the gasification front impacts overall UCG-CCGT-CCS COE. Thereto, a gasification front progresses of 1 m per day (Seifi et al., 2011, 2013) in the worst-case, of 3 m per day in the reference scenario (cf. Chapter 2.2.4, *UCG Exploitation Scheme*) and 5 m in the best-case scenario were considered. With regard to thinner target coal seams (e.g. Seam 1 and Seam 2 with 4 m to 6.6 m thickness) with up to half of the seam thickness assumed in the reference scenario (8 m in average), the vertical extent of the reactor is lower. Hence, the horizontal progress is higher assuming the same oxidizer injection rate and was assumed conservatively with 5 m for the best-case. In case the daily horizontal progress of the gasification front is 5 m, exploitation of the thinnest coal seam (Seam 1) can be neglected, since coal resources of the remaining thicker coal seams (the thicker the coal seam, the more coal is affected per unit of gasification front progress) are sufficient to provide the daily coal demand of about 3,013 t/day (Seam 2 provides 741 t/day, Seam 3 provides 2,057 t/day and Seam 4 provides 2,448 t/day). Seam 1 induces the highest drilling costs and is only taken into account if the horizontal gasification front progress is less than or equal 3 m/day, because in these cases the daily coal supply provided by the remaining coal seams is not sufficient to fuel the CCGT power plant (a smaller horizontal progress of the gasification front results in less gasified coal per day). The exploitation of thinner coal seams induces higher drilling costs than developing thicker ones, since a safety distance between the gasification channels in accordance to the coal seam thickness should have a ratio of about 2:1 (cf. Chapter 2.2.4, *Well Layout and Diameters*). Thus, the lower the seam thickness, the more gasification channels are required to explore the coal seam resulting in higher drilling costs. In the best-case scenario six injectors (two injectors for every developed target coal seam, Seam 1 is neglected) are taken into account and three gasification channels are operated simultaneously (cf. Figure 3.9). Consequently, drilling costs can be significantly reduced (cf. Figure 3.10). In the worst-case scenario, the horizontal progress of the gasification front was assumed with 1 m per day. Thus, less coal per gasification channel is gasified and a complete exploitation of all four target coal seams with the highest possible gasification channel number is required to ensure the daily coal supply for the CCGT power plant.

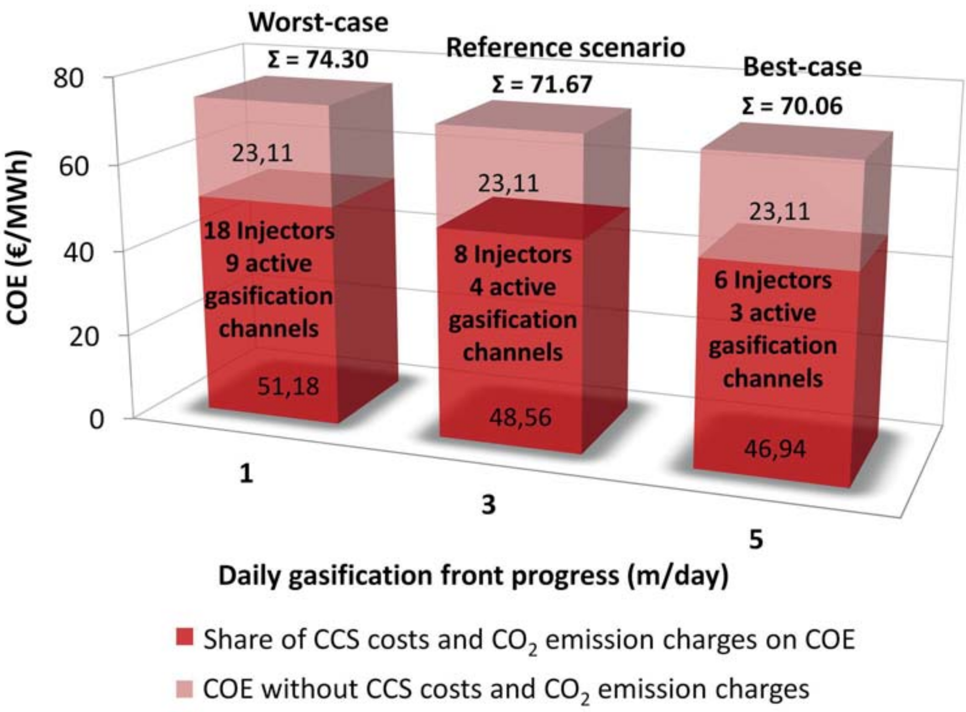

Figure 3.9: Daily horizontal gasification front progress variation from 1 m to 5 m causes an overall COE difference of 4.2 €/MWh, including CO_2 emission handling costs.

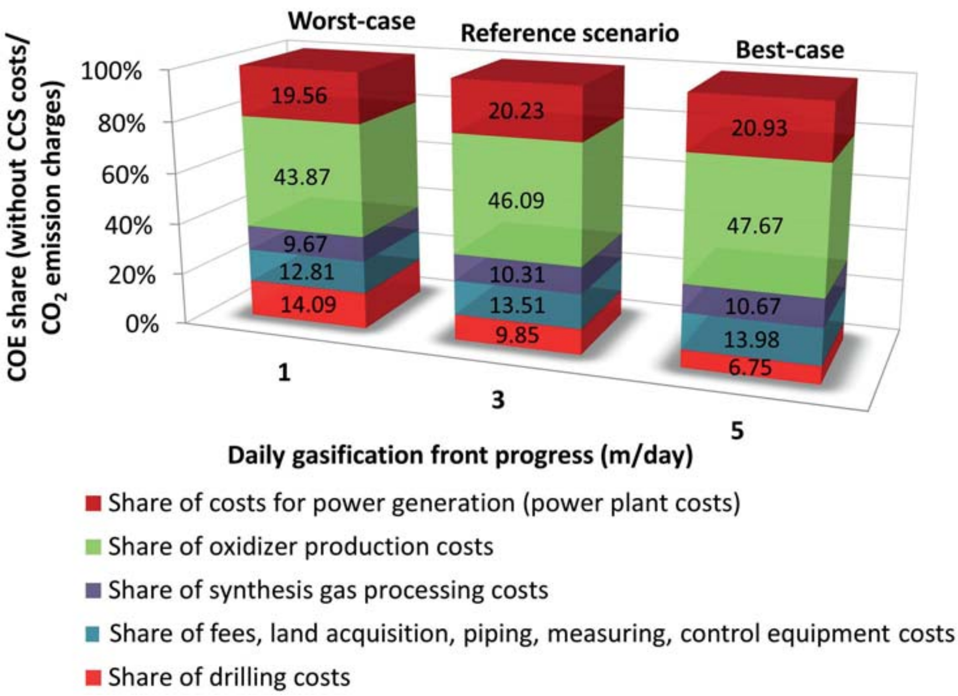

Figure 3.10: Daily gasification front progresses in the reference (3 m), worst- (1 m) and best-case scenarios (5 m) and the resulting percentage impact of fuel and power plant costs on COE, without CCS costs or CO_2 emission charges.

Since one liner can be inserted per vertical injector only, ten additional injectors (18 injection wells in total) have to be drilled to operate nine gasification channels simultaneously in order to provide the daily required coal amount to fuel the CCGT power plant. If (taking into account a horizontal gasification front progress of 1 m per day) the number of active gasification channels is not increased from four (reference scenario) to nine, the available coal amount would account to 1,104 t/day only (Seam 1 provides 54 t/day, Seam 2 provides 148 t/day, Seam 3 provides 411 t/day and Seam 4 provides 490 t/day), whereby 3,013 t/day are required to fuel the CCGT power plant. Compared to the reference scenario, COE decrease by 1.1 % in the best-case scenario and increase by 1.9 % in the worst-case scenario (cf. Figure 3.9). Results depicted in Figure 3.10 show, that the larger the horizontal gasification front progress, the higher the daily coal amount provided per gasification channel and the lower the required number of simultaneously operated gasification channels to ensure the required daily coal amount. The gasification process in each gasification channel is triggered and regulated by a respective liner, whereby due to technical reasons, only one liner can be inserted per vertical injector at once. If less gasification channels are operated simultaneously, less vertical injectors have to be drilled resulting in lower drilling costs (6.8 % share of the overall COE in the best-case scenario compared to 14.1 % in the worst-case scenario). Besides, considering a gasification front progress of 5 m, exploitation of Seam 1 can be neglected as it is only taken into account if the horizontal gasification front progress is less than or equal 3 m/day. This also impacts the decrease of drilling costs in the best-case scenario. In summary, comparing COE in the best- and worst case scenarios reveals an overall margin of 4.2 €/MWh.

Coal Calorific Value

The ratio between the required coal and produced amount of synthesis gas depends on the coal conversion efficiency, the synthesis gas CV_{Syn} and the coal CV_{Coal} (cf. Chapter 2.2.1, *Synthesis Gas Composition*). In the reference scenario, the average coal CV_{Coal} amounts to 34.1 MJ/kg. As well as the variability taken into account for the other geological parameters (seam extent, seam thickness, seam depth), variability for the worst- and best-case scenarios was appointed with ±10 %. A lower variability was not considered, since COE sensitivity to drilling costs related model input parameters is insignificant. A higher bandwidth was not considered, as in line with a lower CV_{Coal} coal quality decreases resulting in a higher coal demand to supply the CCGT power plant (daily coal consumption varies between 2,793 t to 3,273 t in the different scenarios). Taking into account a coal CV_{Coal} of 30.7 MJ/kg (worst-case), coal resources are barely sufficient to supply the CCGT power plant for a 20 years lifetime. Compared to the reference scenario, COE increase by 2.2 % in the worst-case scenario and decrease by 1.7 % in the best-case scenario (cf. Figure 3.11). Comparing the best- and worst case scenarios reveals an overall margin of 4.2 €/MWh.

As Figure 3.12 depicts, the COE differences result from different consumed coal amounts, and hence altering drilling costs. Assuming worst-case conditions, the thinnest coal seam has to be exploited by the maximum number of 67 gasification channels to provide the coal demand, whereby in the best-case scenario the according seam can be neglected completely. Due to the smaller area, in the best-case scenario CO_2 storage capacity in the UCG voids decreases to 19 %. Accordingly, more CO_2 is released into the atmosphere resulting in higher CO_2 emission charges, and thus increasing overall CO_2 emission handling costs in the best-case scenario.

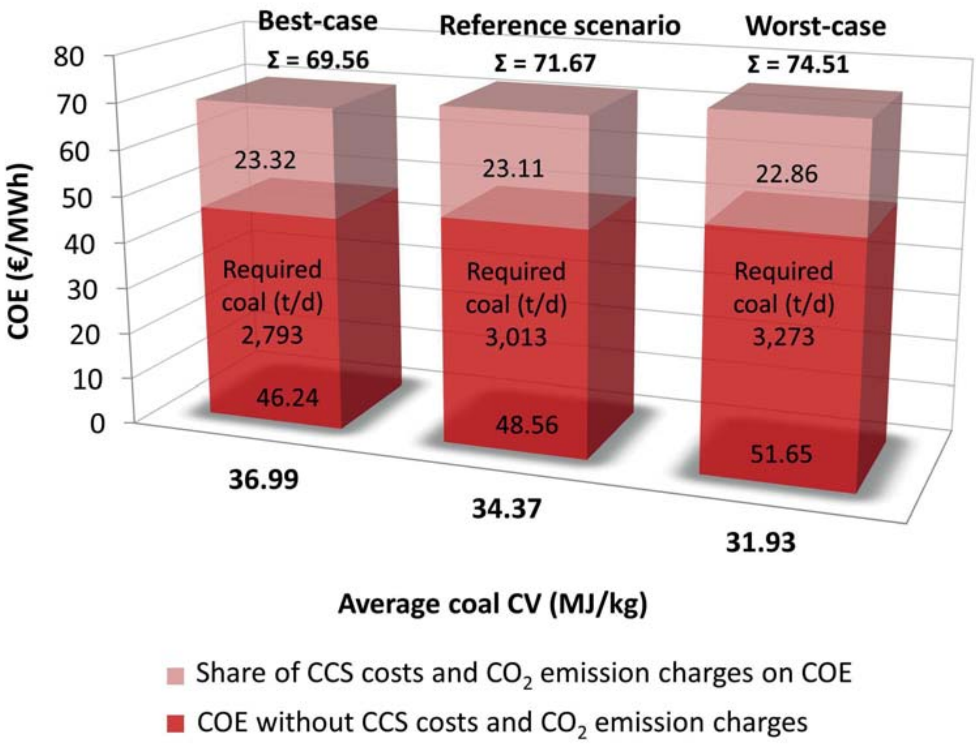

Figure 3.11: Coal CV_{Coal} variation from 31.93 MJ/kg to 36.99 MJ/kg causes a COE bandwidth of 5 €/MWh (including CO_2 emission handling costs), modified from Nakaten et al. (2014a).

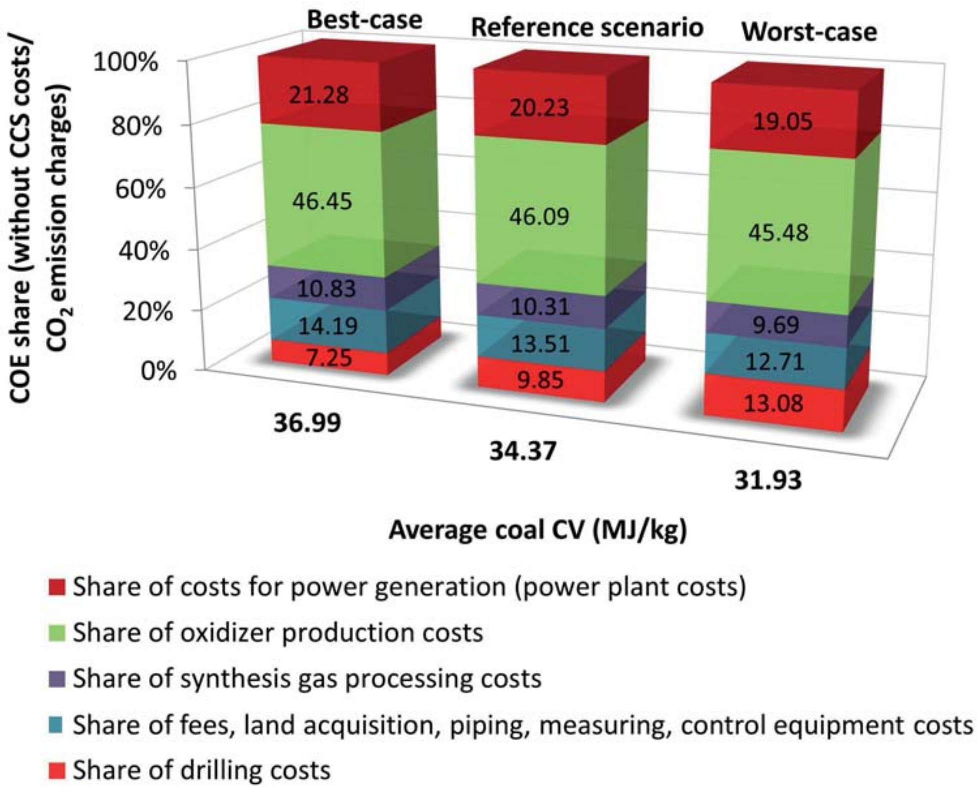

Figure 3.12: Coal CV_{Coal} variation by ±10 % compared to the reference scenario and the resulting percentage impact of fuel and power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

3.1.2 Chemical Model Boundary Conditions

The chemical synthesis gas composition has a significant impact on the resulting UCG synthesis gas end use. Thereby, the synthesis gas quality is impacted by many variables such as the coal quality (e.g. ash content), operating pressure and temperature (e.g. resulting tar content), water influx to the gasification process, and oxidizer composition as a higher oxygen content simplifies CO_2 separation from H_2O (Beath, 2006; Burton et al., 2006; Stanczyk et al., 2010).

Synthesis Gas Composition

Table 3.2 lists the synthesis gas compositions taken into account to analyze the influence of different synthesis gas compositions on COE. Besides the synthesis gas composition considered in the reference scenario, CO_2- and CH_4-rich synthesis gases, and a (due to reduced H_2 and CH_4 amounts) poor quality gas composition as determined based on experimental studies carried out by Stanczyk et al. (2010); Shu-Gin et al. (2009), were investigated.

Table 3.2: Synthesis gas compositions taken into account in the sensitivity analysis (Stanczyk et al., 2010; Nakaten et al., 2014a).

Composition elements	H_2	CH_4	CO	N_2	CO_2
Poor quality (%)	10	10	10	47	23
Reference scenario (%)	21	11	10	35	23
High CO_2 amount (%)	21	11	10	10	48
High CH_4 amount (%)	11	21	10	35	23

Within the investigated synthesis gas compositions, the composition with an increased CH_4 amount represents best-case conditions, achieving a calorific value of 10 MJ/sm^3. The high calorific value increases gas quality, resulting in a lower fuel demand. Thus, the daily required coal amount to supply the 308 MW CCGT power plant can be reduced by 750 t/day. The exploitation of the remaining two thinner target coal seams was therefore not considered in this scenario, since assuming a gasification front progress of 3 m per day, the two thicker seams are sufficient to provide the necessary daily coal amount. Due to reduced drilling costs, COE decrease in this scenario amounts to 3.5 % compared to the reference scenario (cf. Figure 3.13). Despite the lower amount of required synthesis gas (200,681 sm^3/h instead of 356,538 sm^3/h) and reduced oxidizer mass flows (2,280 sm^3/h instead of 2,935 sm^3/h), synthesis gas processing and oxidizer production CAPEX do not decrease. This attributes to the fact, that the synthesis gas

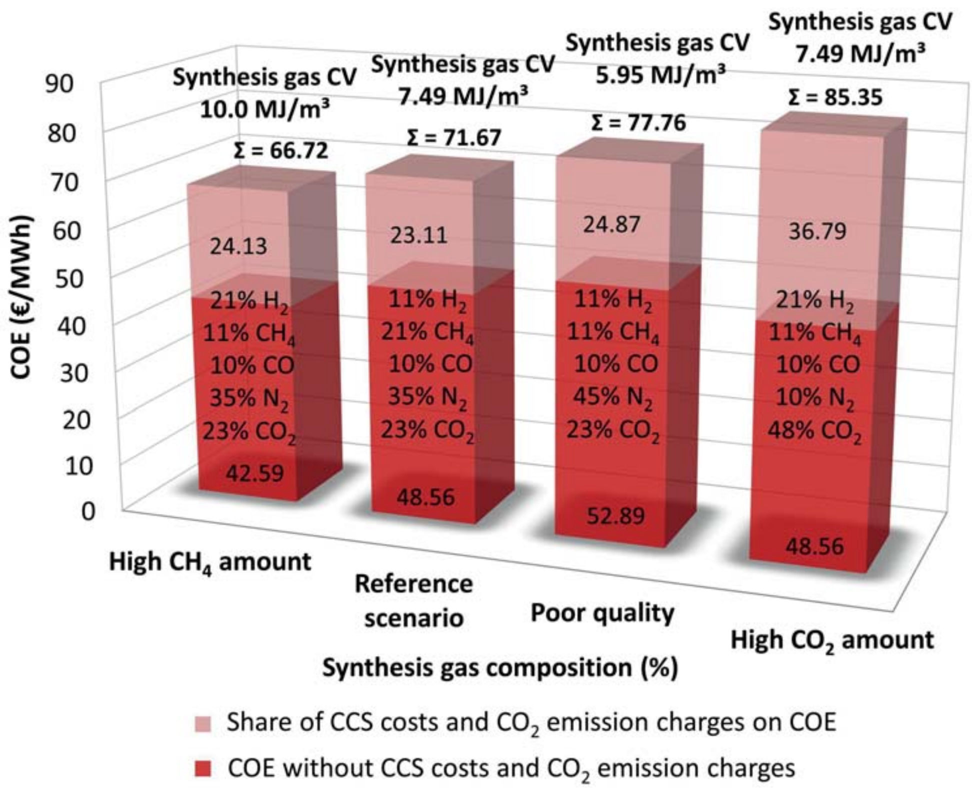

Figure 3.13: Variation of synthesis gas quality causes an overall COE difference of 18.6 €/MWh (including CO_2 emission handling costs), modified from Nakaten et al. (2014a).

processing and the ASU process setup are linked to the power plant capacity and the operating hours constituted in the reference scenario. These remain constant in the worst- and best-case scenarios (cf. Figure 3.14). Costs for CO_2 emission handling in the underlying best-case scenario exceed COE for the reference scenario by 1 €/MWh, because neglecting the exploitation of two target coal seams decreases the CO_2 storage capacity to 12.6 %. Even though the reduced synthesis gas amount results in a slight CO_2 emission drop, the share of CO_2 emission charges on overall CO_2 handling costs increases as more CO_2 is released into the atmosphere paying CO_2 emission charges, which exceed CCS costs by 10 €/t CO_2. CCS costs in the present study are lower than CO_2 emission charges, because the CO_2 capture rate is adjusted to the relatively low storage capacity in the former UCG voids. The worst-case scenario is the CO_2-rich composition with a CO_2 share of almost 50 %, resulting in a higher CCGT power plant emission rate of 1.58 t CO_2/MWh (compared to 1 t CO_2/MWh in the reference scenario). The high CO_2 amount causes higher CO_2 handling costs (36.79 €/MWh compared to 23.11 €/MWh in the reference scenario) causing an overall COE increase by 9.8 % (cf. Figure 3.13). In line with the increased CO_2 emission rate, whereby the storage capacity is constant, only 13 % of the emitted CO_2 can be stored in the former UCG voids. Hence, the CO_2 capture rate is adjusted to the storage capacity in this case, whereby 87 % (compared to 79.5 % in the reference scenario) of

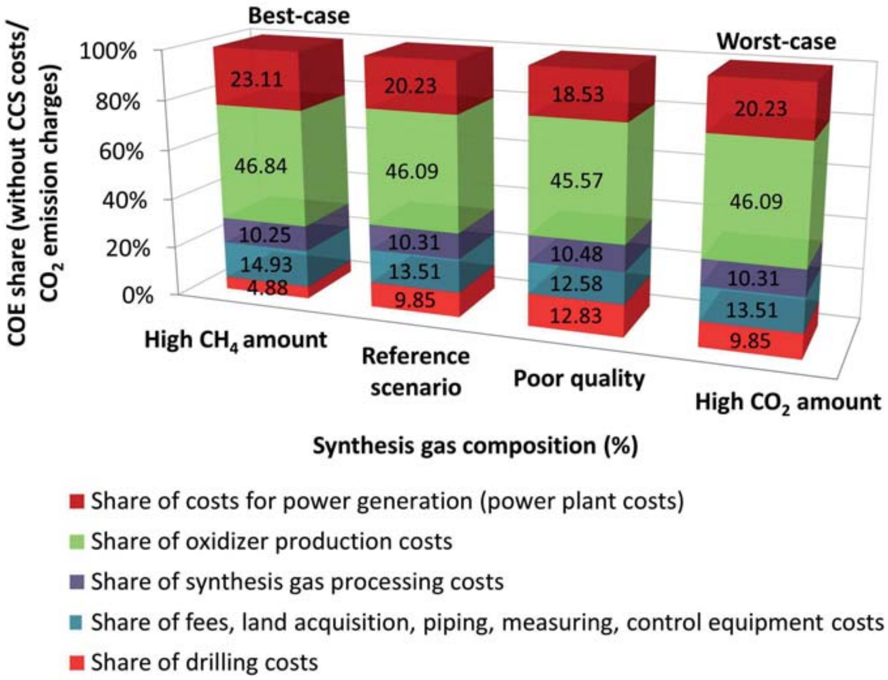

Figure 3.14: Variation of synthesis gas quality and the resulting percentage impact of fuel costs and other power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

the produced CO_2 is released to the atmosphere increasing the share of CO_2 emission charges on CO_2 handling costs. The COE difference between the best- and worst-case scenarios is about 18.6 €/MWh (cf. Figure 3.13). The synthesis gas CV_{Coal} in the worst-case scenario amounts to 7.5 MJ/sm^3, as the gas CV_{Coal} in the reference scenario, since the methane content is equal. The synthesis gas CV_{Coal} in the poor synthesis gas composition scenario decreases to 5.95 MJ/sm^3 resulting in an increased daily coal demand of about 500 t (compared to the reference scenario). Although the oxidizer demand (3,151 sm^3/h) and the synthesis gas production (486,078 sm^3/h) are increased in this scenario, synthesis gas processing and oxidizer production CAPEX do not increase accordingly. This is because of ASU and synthesis gas processing processes being linked to the power plant capacity and the operating hours in the reference scenario, which are equal in all four scenarios (cf. Figure 3.14). Compared to the reference scenario, a complete exploitation even of the thinnest target coal seam (67 gasification channels instead of 25 in the reference scenario) had to be considered, causing a drilling costs increase by 3 %. The higher number of gasification channels slightly increases the CO_2 storage capacity to 21.9 %. Nevertheless, the power plant emission rate increases to 1.1 t CO_2/MWh. This effect keeps CO_2 handling costs differences between the accordant scenarios relatively low.

3.1.3 Technical Model Boundary Conditions

Technical model boundary conditions taken into account in the context of the present sensitivity analysis are the annual UCG and CCGT power plant operating hours as well as the CCGT power plant efficiency.

CCGT Power Plant Operating Hours

According to the UCG plant availability, in Chapter 2.3.5 (*UCG Synthesis Gas Fueled CCGT Power Plant*), an annual CCGT power plant availability of 8,000 operating hours was taken into account for the reference scenario. To evaluate COE differences in accordance to different availabilities of the UCG plant, annual operating hours in the worst-case amount to 6,000 hours (since UCG synthesis gas production costs have a share of up to 80 % on overall COE, a lower plant availability is economically not reasonable) and in the best-case scenario to 8,322 hours. Calculation results depicted in Figure 3.15 show, that compared to the reference scenario 322 additional annual operating hours decrease COE by 0.9 %, whereby reducing annual operating hours to 6,000 hours causes a COE increase of 7.4 %.

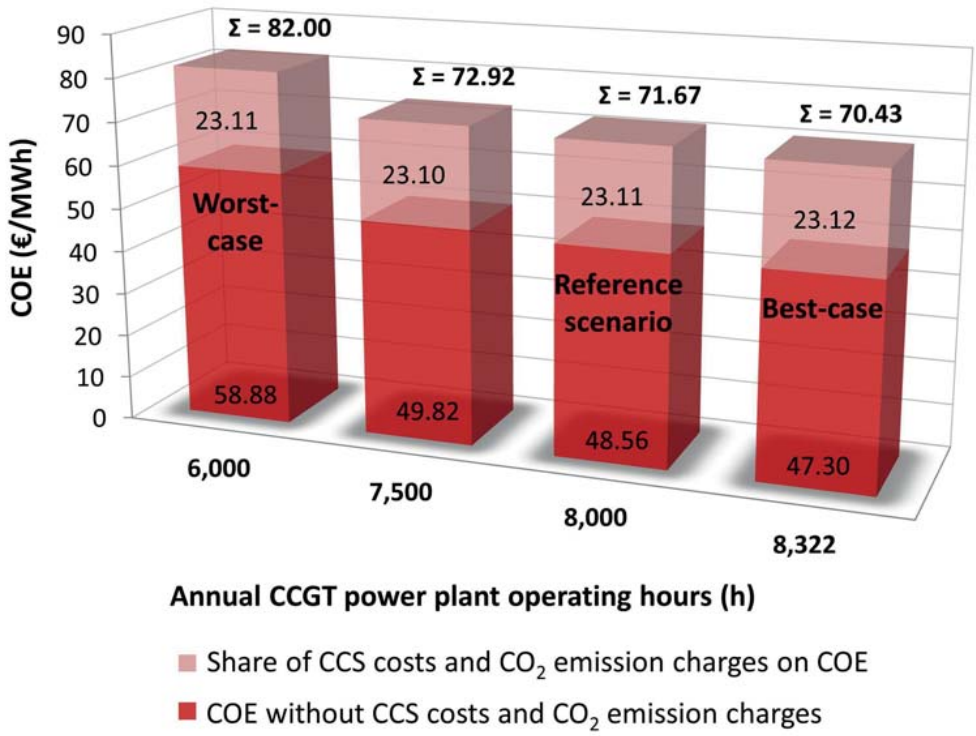

Figure 3.15: CCGT power plant operating hours variation from 6,000 hours to 8,322 hours causes an overall COE bandwidth of 11.6 €/MWh (including CO_2 emission handling costs), modified from Nakaten et al. (2014a).

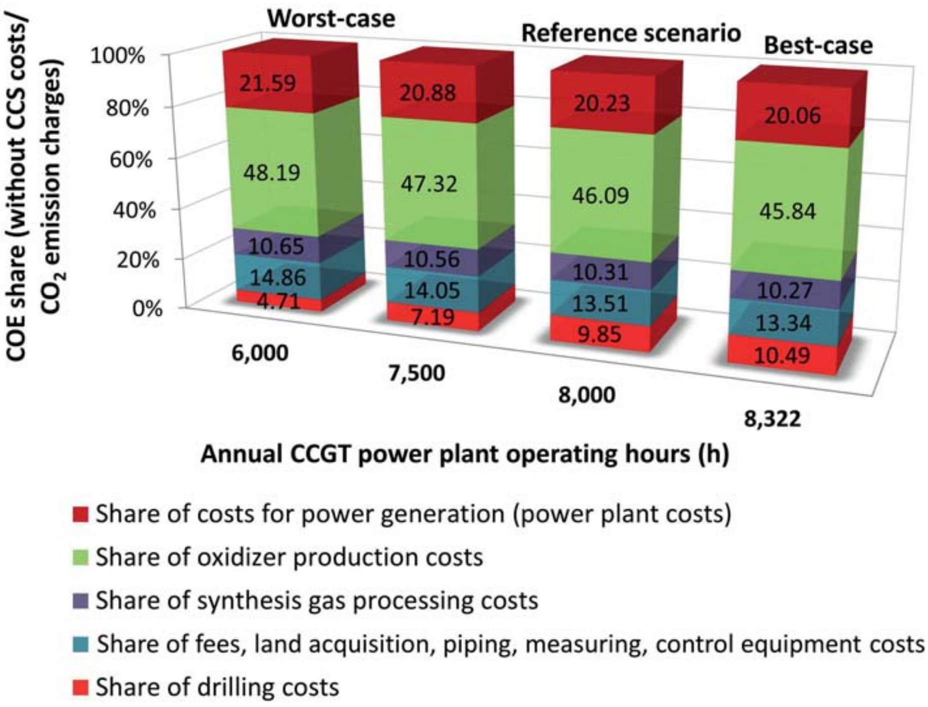

Figure 3.16: CCGT power plant operating hours variation from 6,000 hours to 8,322 hours and the resulting percentage impact of fuel costs and other power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

In summary, a difference of 2,233 annual operating hours between worst- and best-case conditions causes a COE margin of 11.6 €/MWh. Since the CO_2 emission rate maintains constant in the investigated scenarios, CCS costs and CO_2 emission charges do not vary.
Figure 3.16 shows the influence of fuel costs and power plant costs on COE under consideration of varying annual operating hours. The correlation between varying operating hours and drilling costs is attributable to the fact that less operating hours reduce the coal demand, and thus the intensity of coal seam development. Accounting for 6,000 operating hours, exploitation of the thinnest coal seam can be neglected completely and for the remaining coal seams the amount of gasification channels can be reduced by five per coal seam to reduce drilling costs. One target coal seam is negligible considering 7,500 operating hours, whereby in case of 8,000 and 8,322 operating hours coal resources of every seam (development of the thinnest coal seam via 25 gasification channels in both scenarios) are required to supply the coupled CCGT power plant.

CCGT Power Plant Efficiency

Taking into account 12 % energy losses due to the coupled air separation, CCS and synthesis gas processing, the CCGT plant efficiency of originally 58 % (Konstantin, 2009) in the reference scenario is determined with 46 % in total (cf. Chapter 2.3.5, *UCG Synthesis Gas Fueled CCGT Power Plant*). Figure 3.17 illustrates, that compared to the reference scenario a power plant efficiency increase to 48 % in the best-case scenario (60 % neglecting power losses) causes a COE decrease by 2.8 €/MWh including CCS costs (Schneider, 1998). In contrary, a low CCGT power plant efficiency of 30 % in the worst-case scenario (40 % to 42 %) increases COE by 20.8 €/MWh (Schneider, 1998). The margin between best- and worst-case scenarios is caused by a varying fuel yield as a result of different power plant efficiencies. Lower efficiencies diminish the heat input yield resulting in a lower net electric output at constant operating and investment expenses, thus increasing overall COE. Considering a CCGT plant efficiency of 46 % and a heat input of 743 MW_{th}, the net electric power output in the reference scenario is 308 MW_{el}. The heat input results from UCG synthesis gas combustion whereby the portion not converted into work ends up as waste heat. Maintaining a constant heat input and increasing the CCGT power plant efficiency to 48 % results in a net electric power output increase to 321 MW_{el}. In order to provide a comparative basis between all scenarios, only the required fuel input is varied in accordance to the power plant efficiency. Hence, taking into account a power plant efficiency of 48 %, the daily required coal input reduces by 121 t (compared to the reference scenario taking into account a power plant efficiency of 46 %). Expecting a low CCGT power plant efficiency of 30 % (worst-case scenario), the net electric output decreases to 201 MW_{el}. In this case, the daily coal consumption has to be increased by 1,605 t to scale the low net electric output to the process setup dimensions of the reference scenario. However, considering a coal consumption of 4,618 t per day, coal resources will suffice for 16 years only, whereby by reason of economic considerations, the operational time has to be at least 20 years. Besides, to provide the increased coal demand, seven additional gasification channels per coal seam are required. However, this option is not considered, since the safety distance of a 1:2 ratio between the gasification channels and the coal seam thickness must be maintained (cf. Chapter 2.2.4, *Well Layout and Diameters*). Thus, in order to ensure the coal supply to operate the coupled UCG-CCGT-CCS system for an operational time of 20 years based on a save exploitation infrastructure, the power plant efficiency in the current study must not be below 38 % (compared to the reference scenario, the coal requirement increases by additional 640 t of coal per day). Besides reduced drilling costs (cf. Figure 3.18), another reason for COE decrease in the best-case scenario is that the reduced coal consumption is accompanied with slightly lower OPEX for oxidizer production and synthesis gas processing. Beyond that, changing the CCGT power plant efficiency also affects the CO_2 emission rate (CO_2 emissions per MWh produced electricity), and hence CO_2 emission handling costs.

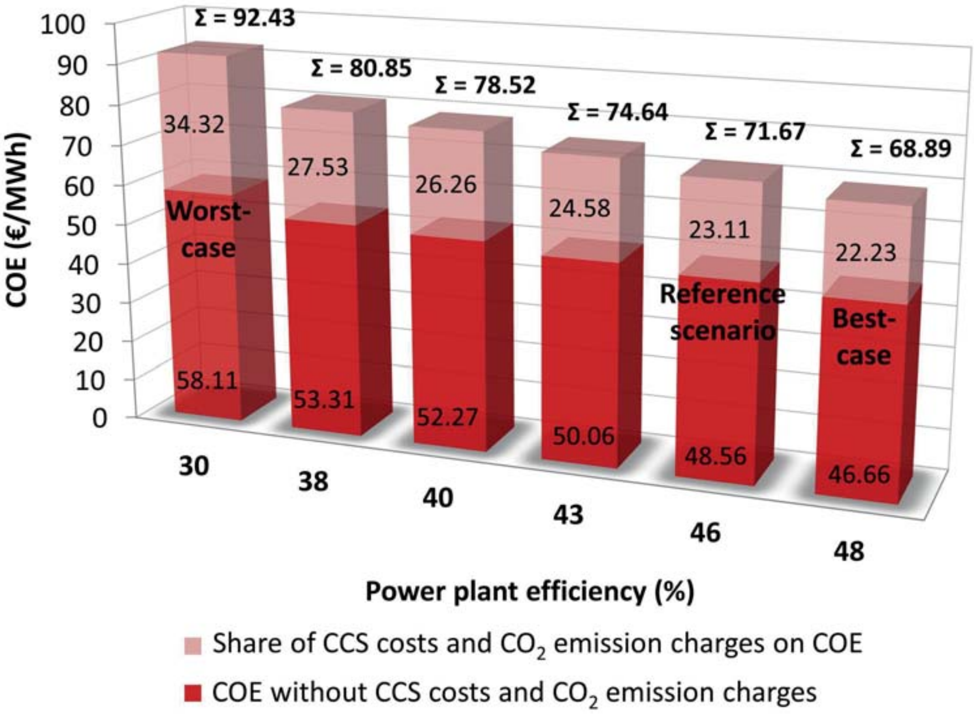

Figure 3.17: CCGT power plant efficiency variation from 30 % to 48 % causes a COE bandwidth of 23.5 €/MWh, including CO_2 emission handling costs (Nakaten et al., 2014a).

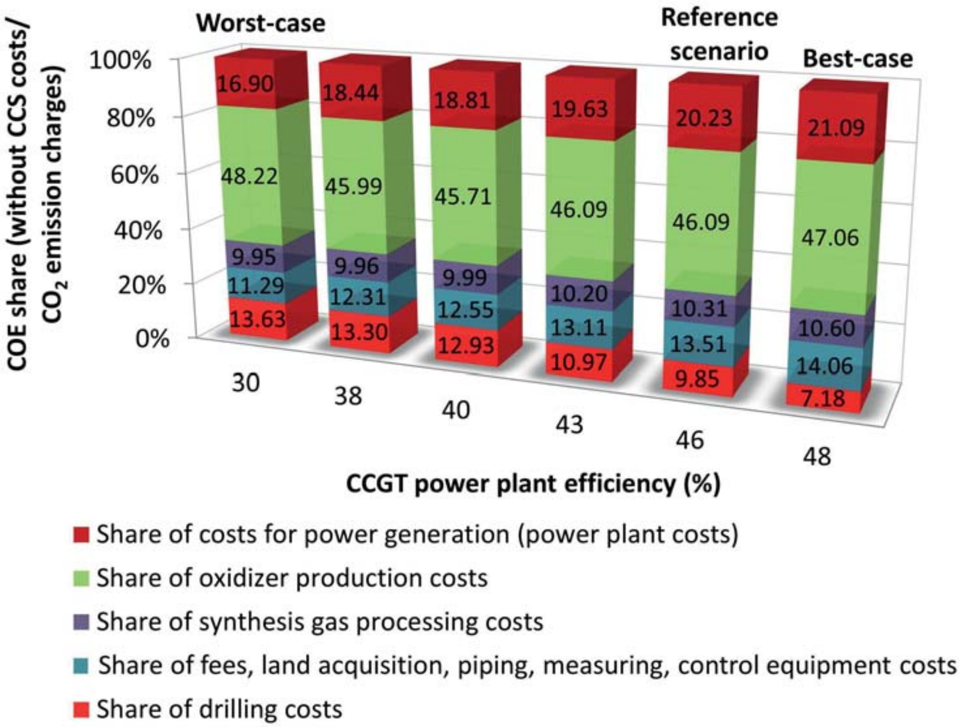

Figure 3.18: CCGT power plant efficiency variation from 30 % to 48 % and the resulting percentage impact of fuel costs and power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

While in the reference scenario the CO_2 emission rate is about 1 t CO_2/MWh, it amounts to 1.54 t CO_2/MWh in the worst- and to 0.96 t CO_2/MWh in the best-case scenario. The percentage influence of fuel and power plant costs on COE assuming power plant efficiencies between 30 % to 48 % is visualized in Figure 3.18. The increasing impact of drilling costs on COE taking into account power plant efficiencies of 30 %, 38 %, 40 % and 43 % (cf. Figure 3.18) can be led back to the fact, that for the exploitation of additional coal resources more gasification channels are required. Contrary, to reduce drilling costs, exploitation of the thinnest coal seam in the reference scenario was conducted to the extent coal demand is assured in order to reduce drilling costs. That means, applying 25 gasification channels only (cf. Chapter 2.2.4, *Well Layout and Diameters*) while the coal seam geometry allows for a drilling infrastructure with up to 67 gasification channels. In the best-case scenario the respective coal seam was completely neglected to reduce drilling costs.

3.1.4 Market-Dependent Model Boundary Conditions

Market-dependent model input parameters taken into account in the present sensitivity analysis are costs for drilling, synthesis gas processing, the nominal CCGT power plant interest rate, oxidizer production costs and CO_2 emission charges.

Average Drilling Costs

Drilling costs for injection and production wells as well as for horizontal in-seam drillings (gasification channels) taken into account for the underlying calculations had to be anonymized and are not presented in detail in the current study (cf. Chapter 2.3.4, *Underground Coal Gasification*). Varying averaged drilling costs by ±25 % (high uncertainty level to cover e.g. unpredictable incidents, different price offers, changing market boundary conditions) compared to the reference scenario, COE increase and decrease by about 0.9 % (cf. Figure 3.19). Costs for CO_2 emission handling do not vary in the underlying scenarios. Figure 3.20 depicts the percentage influence of fuel and power plant costs on COE assuming drilling costs in the reference, as well as in the best- and worst-case scenarios.

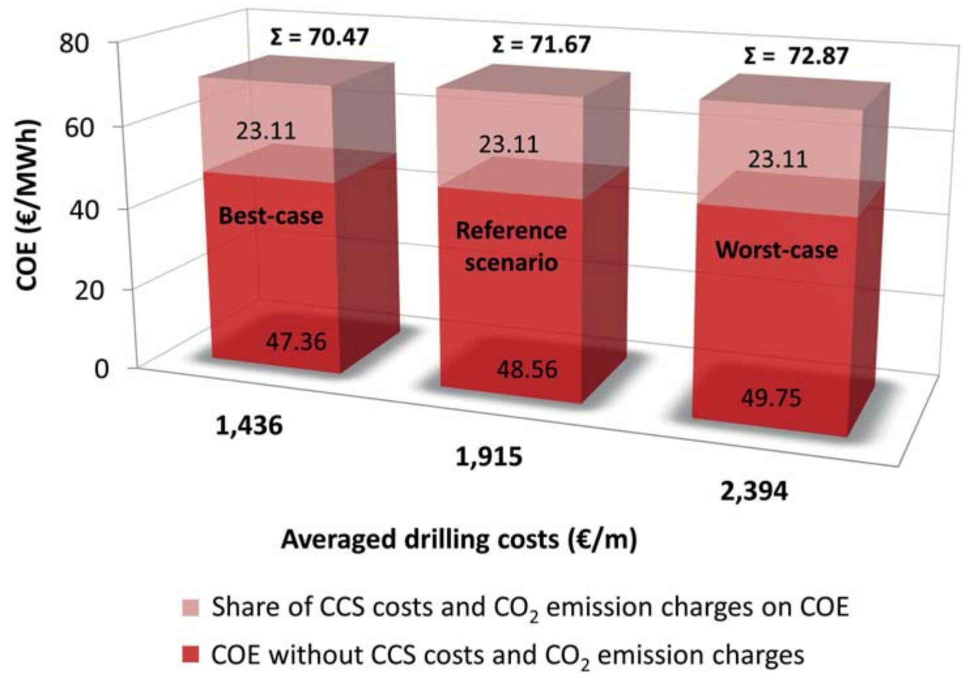

Figure 3.19: Drilling costs variation from 1,436 € to 2,394 € causes an overall COE bandwidth of 2.4 €/MWh, including CO_2 emission handling costs.

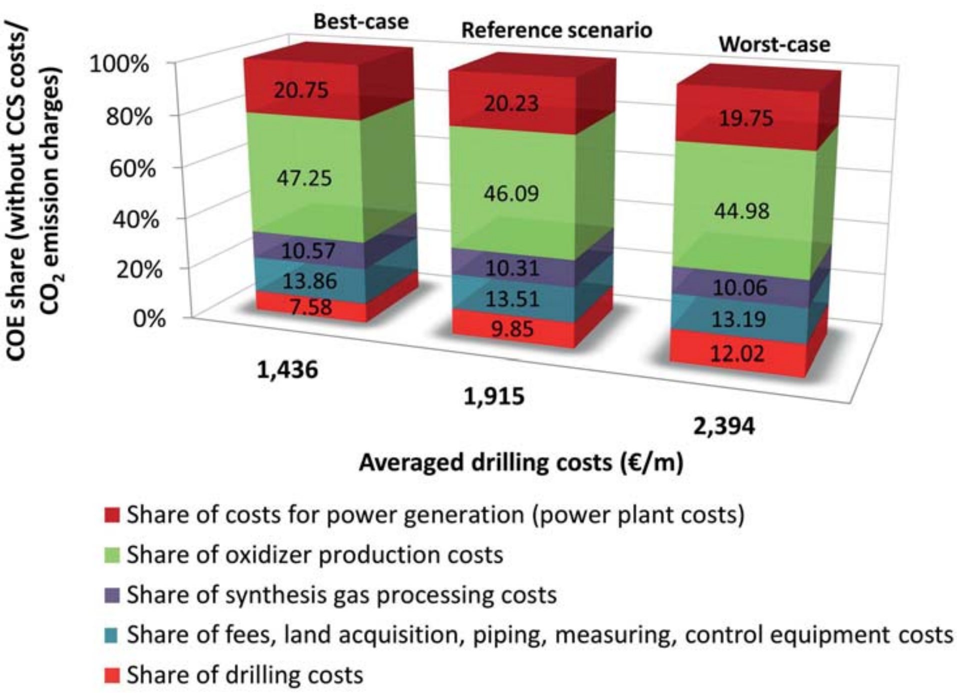

Figure 3.20: Drilling costs in the reference- (1,915 €), worst- (2,394 €) and best-case (1,436 €) scenarios and the resulting percentage impact of fuel and power plant costs on COE, without CCS costs or CO_2 emission charges.

Synthesis Gas Processing Costs

Figures 3.21 and 3.22 show the results for synthesis gas processing costs variation from 185 m€ to 308 m€. Thereby, Synthesis gas processing costs were modeled using the IECM tool by Heaps (2012) and scaled to the process setup of the coupled UCG-CCGT-CCS process.

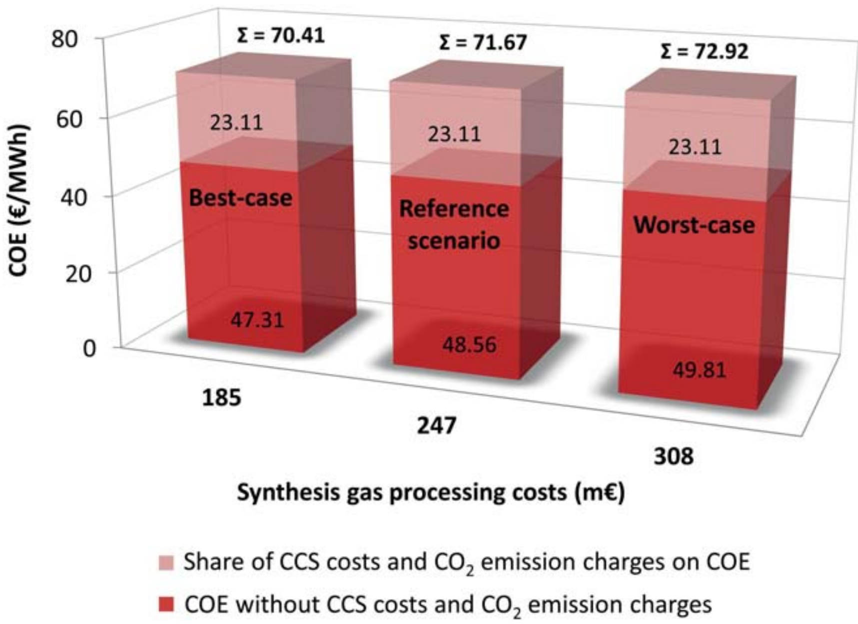

Figure 3.21: Synthesis gas processing costs variation from 185 m€ to 308 m€ causes a COE difference of 2.5 €/MWh, including CO_2 emission handling costs (Nakaten et al., 2014a).

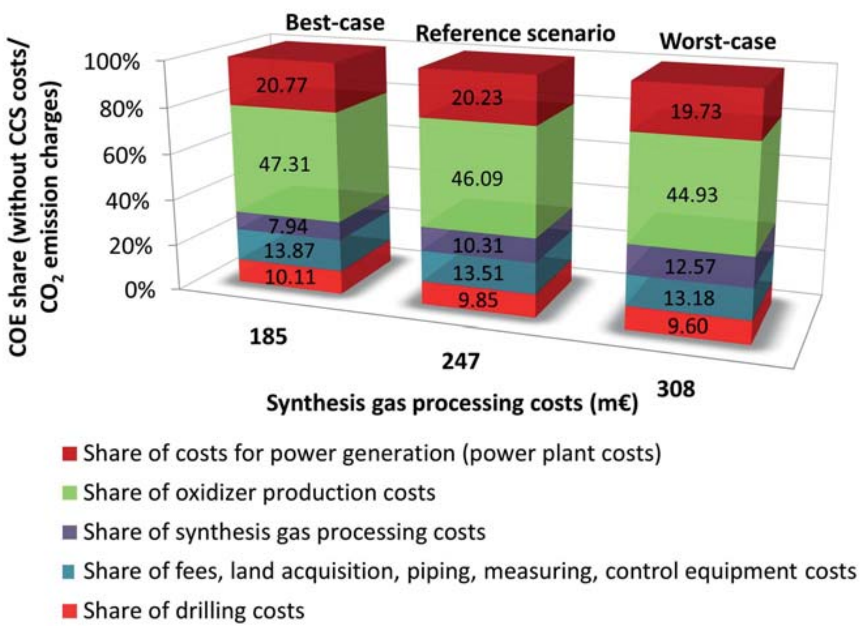

Figure 3.22: Synthesis gas processing costs variation from 185 m€ to 308 m€ and the resulting impact of fuel costs and power plant costs on COE, modified from Nakaten et al. (2014a).

Varying synthesis gas processing costs by ±25 % compared to the reference scenario causes a COE difference of 2.5 €/MWh (cf. Figure 3.21). Costs for CO_2 emission handling (CCS costs and CO_2 emission charges) do not vary in the three scenarios. The percentage impact of UCG fuel costs and CCGT power plant costs on overall COE from best- to worst-case conditions amounts to 5 % (cf. Figure 3.22).

Nominal Interest Rate CCGT Power Plant

For the present sensitivity analysis a nominal interest bandwidth between 3 % (best-case scenario) and 9 % (worst-case scenario) was taken into account. According to Konstantin (2009), the nominal interest rate in the reference scenario is 7.5 % (cf. Chapter 2.3.5, *UCG Synthesis Gas Fueled CCGT Power Plant*). Compared to the latter one, COE decrease by 2 % in the best-case scenario and increase by 0.7 % in the worst-case scenario (cf. Figure 3.23). The COE margin between the best- and worst-case scenarios amounts to 3.60 €/MWh. Figure 3.24 demonstrates that the cost position most affected by varying nominal interest rates are the power plant costs.

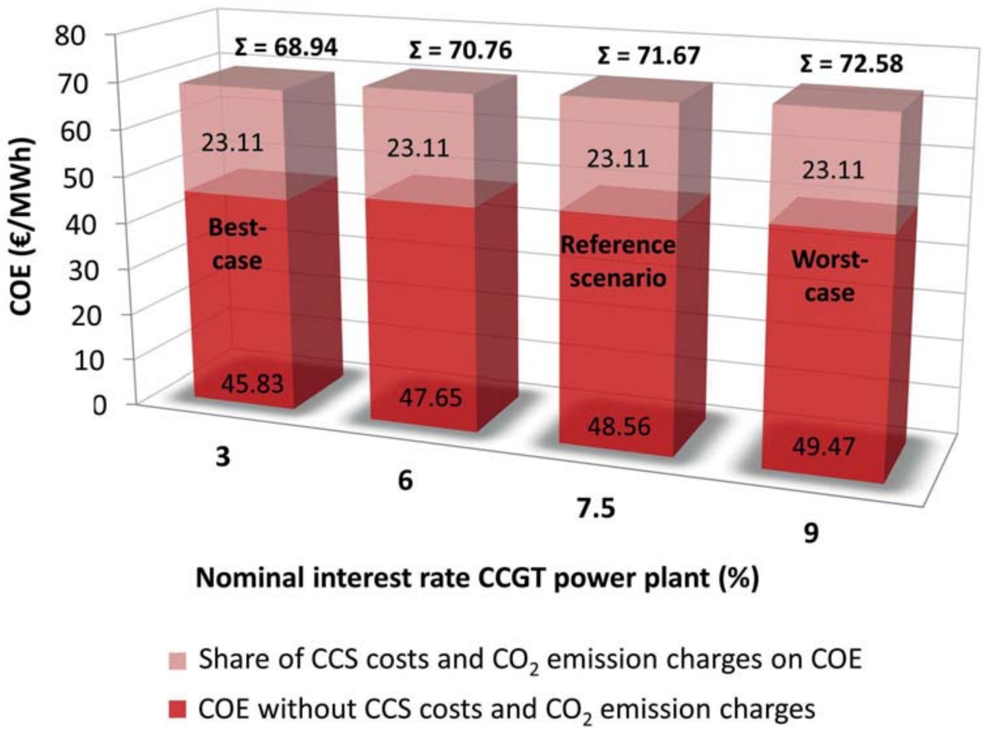

Figure 3.23: CCGT power plant nominal interest rate variation from 3 % to 9 % causes an overall COE bandwidth of 3.6 €/MWh (including CO_2 emission handling costs), modified from Nakaten et al. (2014a).

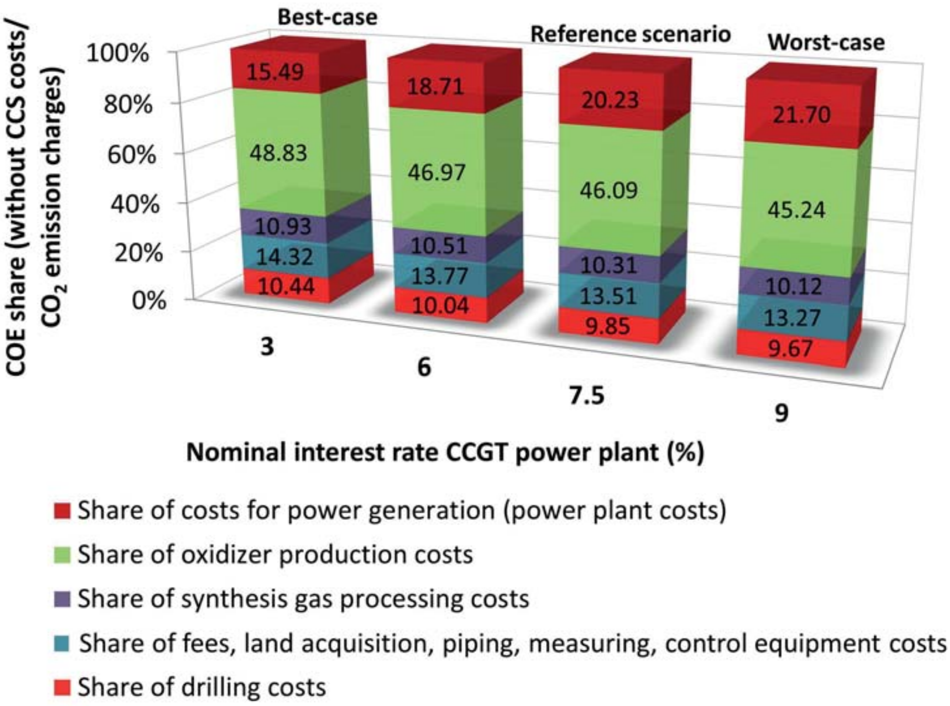

Figure 3.24: CCGT power plant nominal interest rate variation from 3 % to 9 % and the resulting percentage impact of fuel and power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

Oxidizer Production Costs

Oxidizer production costs consist of CAPEX and OPEX for the air separation process as well as for oxidizer compression and injection (cf. Chapter 2.3.1, *Air Separation Unit*). Varying oxidizer production costs from best- to worst-case conditions increase COE by 11.2 €/MWh (cf. Figure 3.25). However, varying oxidizer production costs do not impact CCS costs or CO_2 emission charges, as oxidizer production has no influence on the amount of CO_2 emitted by UCG and electricity generation. In the present study, overall UCG fuel costs contain the cost positions oxidizer production, synthesis gas processing, land acquisition, piping, measuring, control equipment and drilling as well as various fees (e.g. concession fee for coal seam extraction). Figure 3.26 depicts the percentage impact of fuel costs and power plant costs on COE (without CCS costs or CO_2 emission charges) in the reference, worst- and best-case scenarios. Due to their high share (up to about 52 % in the worst-case scenario) on overall costs, oxidizer production costs significantly affect COE.

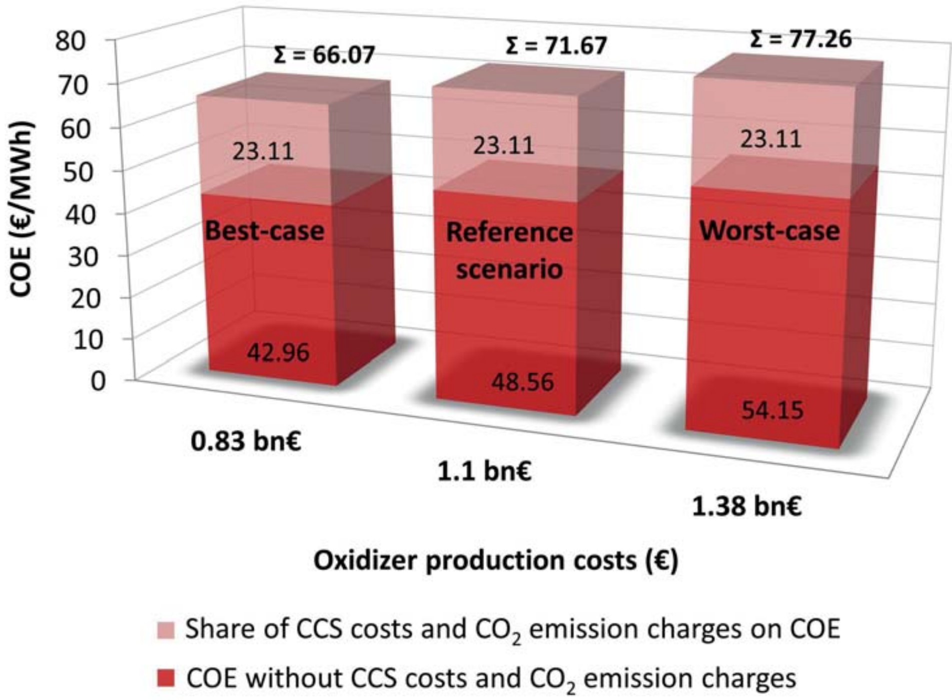

Figure 3.25: Oxidizer production costs variation from 0.83 bn€ to 1.1 bn€ causes an overall COE bandwidth of 11.2 €/MWh, including CO_2 emission handling costs (Nakaten et al., 2014a).

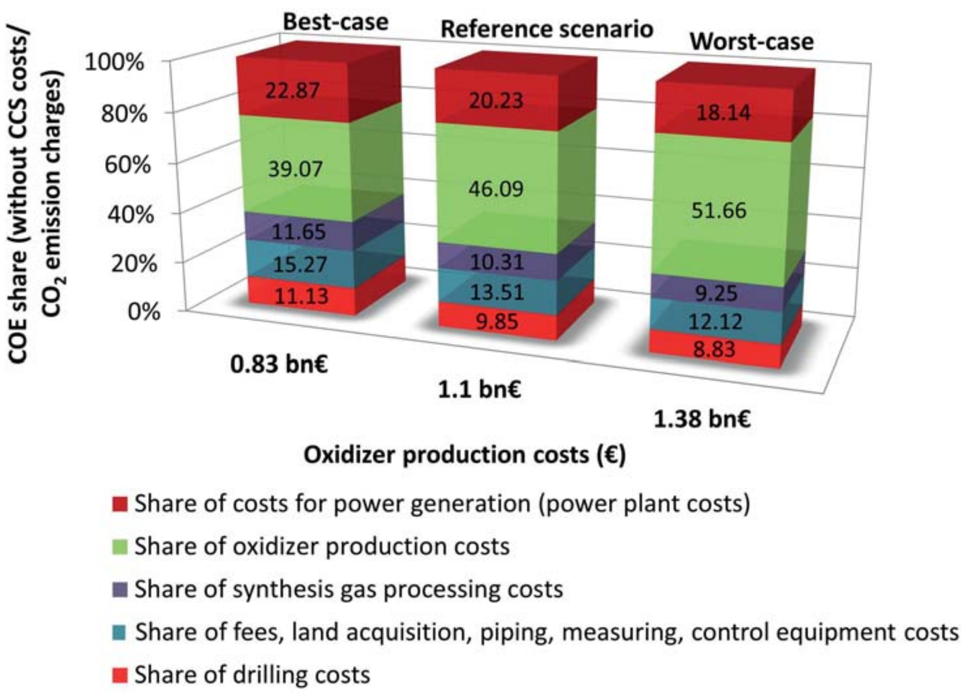

Figure 3.26: Oxidizer production costs variation of ±25 % compared to the reference scenario (1.1 bn€) and the resulting impact of fuel costs and power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

CO_2 Emission Charges

Examining the economic competitiveness of the CO_2 emission handling strategy applied in the present study (cf. Chapter 2.2.2, *CO_2 Emission Handling Strategy*) in comparison to COE without CCS costs but CO_2 emission charges, two modeling cases were assigned. One modeling case considers emission charges for 100 % of the released CO_2 (cf. Figure 3.27, blue curve). The red curve (cf. Figure 3.27) represents the cost development assuming 20.5 % CCS costs for the CO_2 amount captured according to the maximum storage capacity in the UCG voids and 79.5 % CO_2 emission charges paid for the released CO_2 amount.

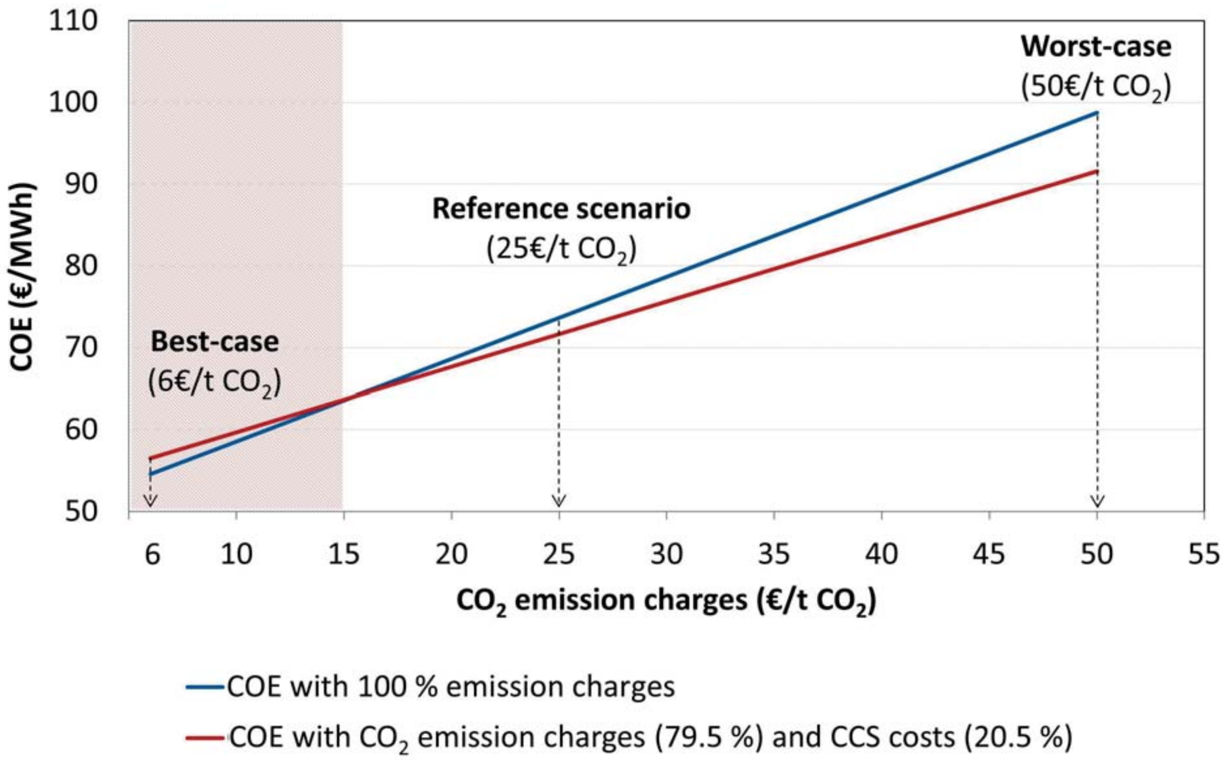

Figure 3.27: CCS costs and COE considering CO_2 emission charges from 6 €/t CO_2 to 50 €/t CO_2 causes a COE bandwidth of 35.1 €/MWh, modified from Nakaten et al. (2014a).

With regard to the best-case conditions CO_2 emission charges of 6 €/t CO_2 were taken into account, whereby 50 €/t CO_2 were assumed as worst-case. In the reference scenario, CO_2 emission charges amount to 25 €/t CO_2 (cf. Chapter 2.2.2, *CO_2 Emission Handling Strategy*). Simulation results show, that in comparison to the reference scenario emission charges of 6 €/t CO_2 decrease COE (including CCS costs) by 10.9 %. CO_2 emission charges of 50 €/t CO_2 increase COE by 14.3 %. Figure 3.27 shows, that the chosen CO_2 emission handling strategy in the present study becomes competitive compared to COE without CCS costs but CO_2 emission charges, as CO_2 emission charges exceed 15 €/t CO_2.

Overview of OAT Sensitivity Analysis Results

The percentage influence of all 14 investigated model input parameters on COE taking into account the values deduced as worst- and best-case conditions in the current study (cf. Table 3.1), are depicted in Figure 3.28.

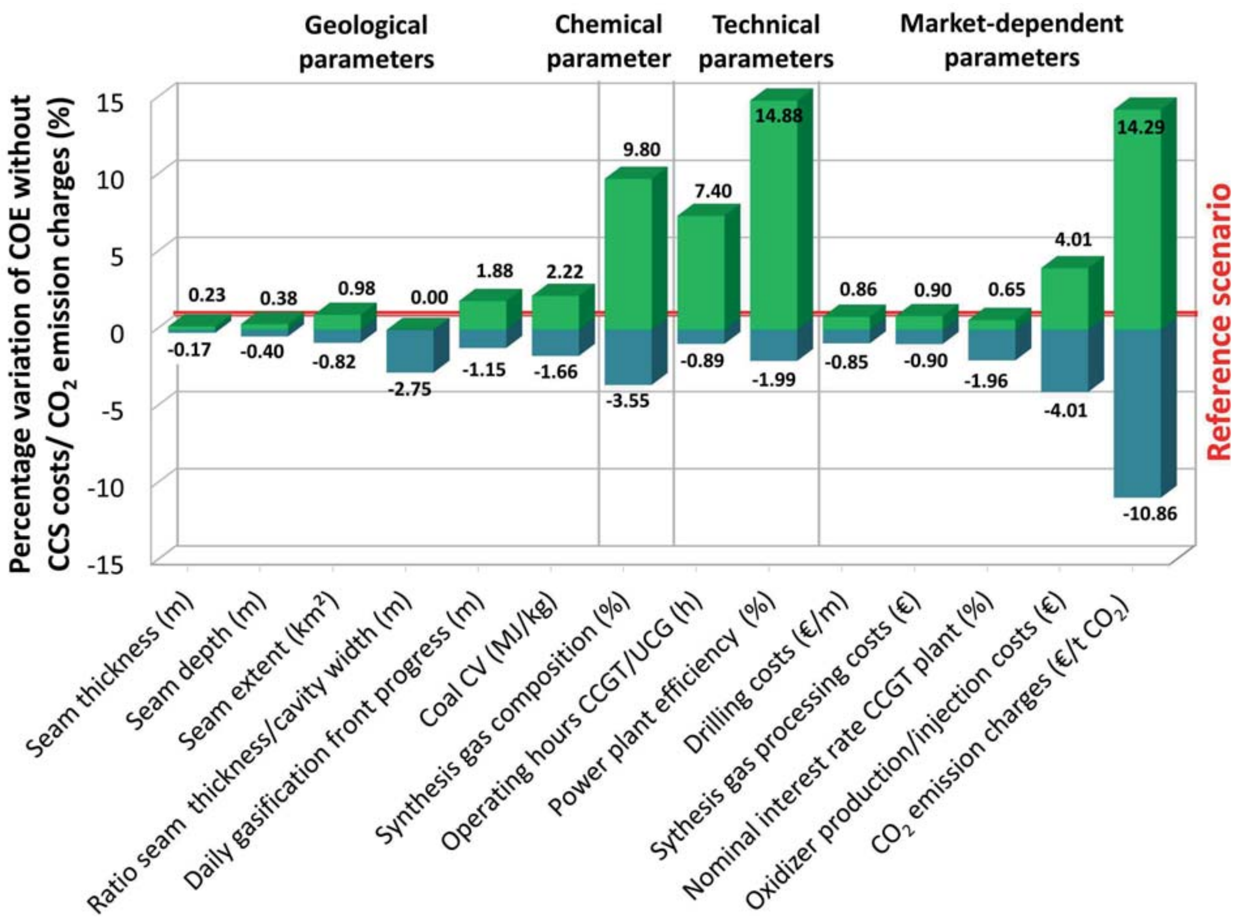

Figure 3.28: Percentage influence of all examined model input parameters on COE (without CCS costs and CO_2 emission charges), modified from Nakaten et al. (2014a).

Differing geological model boundary conditions in the deduced range causes a COE variation bandwidth of minimum 0.4 % (0.6 €/MWh) regarding the seam thickness and maximum 3.9 % (5.4 €/MWh) with regard to the coal calorific value. Taking into account different synthesis gas compositions (high CH_4 and CO_2 compositions, the reference scenario and a poor quality composition) results in a COE variation bandwidth of 13.3 % causing a COE margin of maximum 18.6 €/MWh. Varying technical boundary conditions from the here deduced worst- to best-case conditions causes an overall COE margin of minimum 8.3 % (11.6 €/MWh) with regard to the operating hours and maximum 16.9 % (23.5 €/MWh) with regard to the CCGT power plant efficiency. Differing market-dependent model boundary conditions in the deduced investigation bandwidth causes an overall COE difference of minimum 1.7 % (2.4 €/MWh) regarding drilling costs and maximum 25.2 % (35.1 €/MWh) with regard to the CO_2 emission charges.

3.2 Multivariate Sensitivity Analysis

While OAT sensitivity analysis is undertaken to assess the range in outcomes caused by the variation of one model input parameter across a plausible range of uncertainty (the focus lies on single model input parameters and quantifying their influence on COE to e.g. assess which process step requires optimization), multivariate sensitivity analysis addresses the impact of varying all model input parameters simultaneously to quantify the impact overall boundary conditions related uncertainties have on COE (important for e.g. project planning activities, target area selection). Thereby, the respective assumed best-or worst-case conditions for all investigated parameters are combined to one worst- and one best-case scenario. The multivariate sensitivity analysis undertaken in the present thesis is attended to supplement the OAT sensitivity analysis and relates to the same variables and their variation bandwidths assumed for the afore undertaken OAT sensitivity analysis (cf. Table 3.1). Basic reference scenario setup boundary conditions (cf. *UCG-CCGT-CCS Commercial Scale Setup for the Target Area*, Chapter 2.2) such as seam thickness, extent and depth as well as the CCGT power plant installed capacity and efficiency were maintained constant for the combined parameter variation. Detailed knowledge on site specific geological boundary conditions is an essential precondition for a UCG-CCGT-CCS system implementation, whereby the process dimensions (e.g. CCGT plant installed capacity and the overall surface infrastructure) are strongly related to the geological constraints and are not associated with high uncertainty. However, for an application orientated study it is important to quantify the possible COE variation bandwidth caused by lack of data or varying (e.g. market-dependent) boundary conditions. Thus, multivariate sensitivity analysis in the present study refers rather to model input parameters associated with high uncertainty. Results revealed, that the coal demand in the best-case scenario decreases by 960 t per day resulting from the high quality synthesis gas composition (CH_4-rich composition) and the high coal CV_{Coal}. In the worst-case scenario there is no coal supply shortfall, despite a lower coal CV_{Coal} and a lower quality synthesis gas composition were implied in the scenario setup. However, annual operating hours amount to 6,000 hours only (worst-case conditions operating hours, cf. Chapter 3.1.3, *CCGT Power Plant Operating Hours*), which in turn leads to a reduced exploitation area decreasing drilling costs, also decreasing CO_2 storage capacity to 14.5 %. Costs for CO_2 handling in the worst-case scenario significantly differ to the values achieved in the best-case scenario (62 €/MWh), as the power plant emission rate in the worst-case scenario amounts to 1.56 t/MWh, whereby the CO_2 storage capacity in the UCG voids declines (cf. Figure 3.29). Thus, less CO_2 is stored and more released to the atmosphere, increasing the share of CO_2 emission charges on CO_2 handling costs. Besides, in the worst-case scenario CO_2 emission charges were assumed with 50 €/t CO_2 compared to 6 €/t CO_2 in the best-case scenario.

Figure 3.30 indicates that in the best-case scenario the share of synthesis gas processing, oxidizer production and drilling costs on COE are lower compared to the worst-case scenario as coal demand decreases assuming best-case conditions. However, under best-case conditions fees, land acquisition, piping, measuring and control equipment costs increase significantly while overall UCG fuel costs decrease. This is because the extent of target area exploitation and the related infrastructure is reduced considering the worst-case conditions with 6,000 operating hours only, whereby in the best-case scenario both target areas have to be exploited to ensure fuel supply of the power plant for 8,322 operating hours. Despite decreasing fuel costs, higher synthesis gas quality as well as improved geological and market-dependent boundary conditions, compared to the worst-case the share of power plant costs increases by 4.32 % in the best-case scenario .

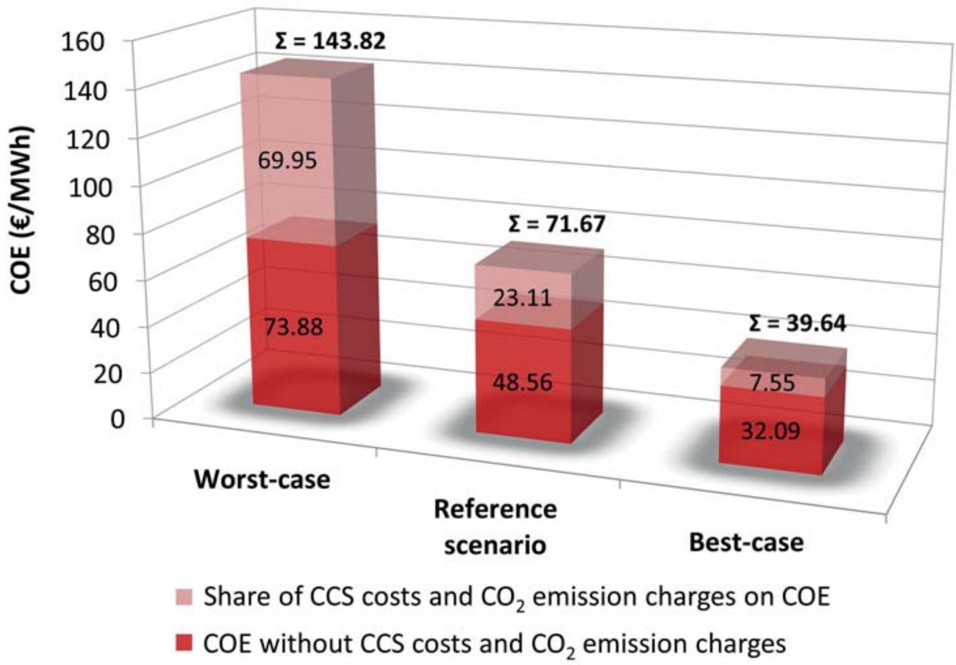

Figure 3.29: Simultaneous variation of selected multivariate sensitivity analysis parameters causes an overall COE difference of 104 €/MWh (including CO_2 emission handling costs) modified from Nakaten et al. (2014a).

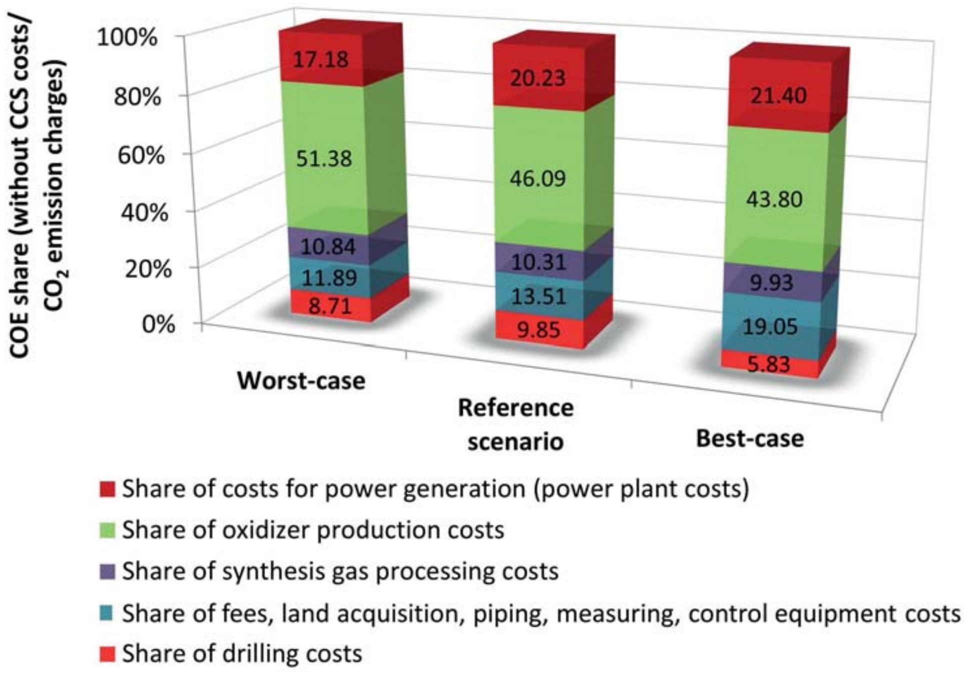

Figure 3.30: Simultaneous parameter variation and the resulting percentage impact of fuel costs and power plant costs on COE (without CCS costs or CO_2 emission charges), modified from Nakaten et al. (2014a).

3.3 Discussion

One-at-a time sensitivity analysis was applied to quantify the range in COE outcomes caused by the variation of one model input parameter across a determined range of uncertainty. Results reveal that varying geological model boundary conditions (seam thickness, depth, extent, thickness to cavity width ratio, daily progress gasification front, coal calorific value), from the accordant determined worst- to best-case conditions causes a COE variation bandwidth of minimum 0.4 % (0.6 €/MWh) with regard to the seam thickness and maximum 3.9 % (5.4 €/MWh) regarding the coal calorific value. Considering different synthesis gas compositions such as high CH_4 and CO_2 compositions, the reference scenario and a poor quality composition, causes a COE variation bandwidth of 13.3 % (18.6 €/MWh). Varying technical boundary conditions (annual operating hours CCGT power plant efficiency) from the determined worst- to best-case conditions causes a COE margin of minimum 8.3 % (11.6 €/MWh) regarding the operating hours and maximum 16.9 % (23.5 €/MWh) regarding the CCGT power plant efficiency. Differing market-dependent model boundary conditions (costs for drilling, synthesis gas processing, nominal interest rate CCGT plant, oxidizer production costs and CO_2 emission charges) in the deduced investigation bandwidth causes a costs of electricity bandwidth of minimum 1.7 %

(2.4 €/MWh) with regard to drilling costs and maximum 25.2 % (35.1 €/MWh) with regard to the CO_2 emission charges.
For parameters aligned with high uncertainty such as e.g. synthesis gas processing and oxidizer production costs, a variability of ±25 % was chosen to ensure that uncertainties are covered. In the present study, high uncertainties refer particularly to the cost intensive surface installation infrastructure, whereby due to lack of data the according variables were scaled linearly to the overall process setup. Indeed, the corresponding parameters underlying linear correlation to changing boundary conditions may suppress economic effects as e.g. economies of scale, which in turn may have an influence on costs of electricity. Since model input data quality correlates with the achievable accuracy of UCG-CCGT-CCS COE quantification, more precise data on the surface facilities and the dynamic scaling of their individual costs to the expected process dimensions will reduce the overall uncertainty range (thus, COE variation bandwidth).
Since the study area is well explored, geological model input parameters are aligned with a relatively low uncertainty, hence compared to the reference scenario the chosen variability amounts to ±10 %. Furthermore, geological parameters are related primarily to drilling costs that are far below other UCG fuel cost positions in the present study. Hence, their impact on COE is low and will even decrease assuming a variability below 10 % causing barely visible changes on COE, only. On the other hand, a higher variability related to the seam extent, coal calorific value and seam thickness will lead to a coal under-supply considering their worst-case conditions.
A further relevant issue are the costs for CO_2 emission handling. In the current study, costs for CO_2 emission handling are mainly determined by CO_2 emission charges. Due to the (generally) low CO_2 storage capacity in the UCG voids only 20.5 % CO_2 can be captured and stored, whereby 79.5 % CO_2 is released to the atmosphere, paying CO_2 emission charges. The CO_2 emission handling strategy becomes competitive compared to COE without CCS costs but CO_2 emission charges, as CO_2 emission charges exceed 15 €/t CO_2. Thereby, CO_2 emission charges in the present study (reference scenario) amount to 25 €/t CO_2 and are varied between 6 €/t CO_2 and 50 €/t CO_2 in the worst- and best-case scenarios. Taking into account higher CO_2 emission charges, e.g. 80 €/t CO_2 presented as worst-case in ZEP (2011), will further increase cost differences between CO_2 emission handling costs and CO_2 emission charges. However, costs for CO_2 emission handling will increase respectively, as CO_2 emission charges have a high share on CO_2 emission handling costs. One possibility to reduce CO_2 emission handling costs is extending CO_2 storage options by e.g. taking into account additional storage capacities in adjacent saline aquifers. Thus, the share of CCS costs on CO_2 emission handling costs would increase and costs for higher CO_2 emission charges will decrease proportionally.

Since knowledge on the required cost budget has a significant impact on the successful implementation of a project, it is important to quantify the influence overall boundary conditions related uncertainties have on COE. Thus, additionally to the OAT sensitivity analysis a multivariate sensitivity analysis was undertaken to assess the impact of varying all model input parameters simultaneously by combining worst-case conditions appointed for the OAT sensitivity analysis to one worst-case scenario and accordingly best-case conditions to one best-case scenario. The results of the multivariate sensitivity analysis demonstrate that varying UCG-CCGT-CCS process and boundary conditions from worst- to best-case conditions, cause significant costs of electricity bandwidths of up to 104 €/MWh in the present study.

As model input parameter variability is determined related to site specific model boundary conditions and their level of uncertainty (due to e.g. data and information availability), sensitivity analyses have to be undertaken for each selected target area individually and can not be transposed from one target area to another. Nevertheless, some general tendencies can be noted. To ensure a secure UCG operation, geological and hydrogeological boundary conditions have to be examined precisely before a target area is chosen. Hence, these factors are associated generally with low uncertainty. On the contrary, model input parameters affected by external unpredictable influences (e.g. market-dependent factors, technological progress) are generally associated with a higher uncertainty resulting in higher COE variation bandwidths.

4 UCG-CCGT-CCS and CCS-PP Implementation

To quantify economical potentials or limitations UCG-CCGT-CCS provides for the Bulgarian energy system, the techno-economic model developed to investigate

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economics at a local scale for a specific target area in Bulgaria (cf. Chapter 2, *Developed Techno-Economic Model for UCG-CCGT-CCS COE Determination*) was interfaced to a macro scale energy system-modeling framework. This is an elementary step of assessment, since besides geological boundary conditions UCG-CCGT-CCS feasibility and cost-effectiveness strictly depend on geographical and infrastructural boundary conditions, as e.g. the presence and location of exploitable resources, the availability of power generation infrastructure as well as the energy transport networks to supply potential end users with the UCG products. A large part of the results presented in Chapter 4 recline on Nakaten et al. (2013).
To achieve a sustainable and resource saving energy management, the EU developed objectives recorded in the Directive 2009/28/EC of the European Parliament and of the Council (EU, 2009). However, the current Bulgarian energy system is designated by a high share of fossil power in the overall energy mix (59 % in 2010) and a technically outdated power generation system, whereby almost 50 % of all power plants are older than the average power plant lifetime of 40 years proposed by Konstantin (2009). The latter hamper the achievement of the EU environmental targets which presuppose 21 % CO_2 emission mitigation until 2020 compared to 2005 and of 80 % until 2050 compared to 1990 (MEW, 2012). So far, Bulgaria pursuits the ambitious EU goals on emission reduction by a high share of nuclear power in the energy mix (46 % until 2020). Since the capacities for water power (8 % of the energy mix in 2010) are almost fully exploited, the extension of renewable energy regarding waste, biomass, solar and wind power has to be high to meet the EU environmental targets (MEET, 2011a). The current Bulgarian fossil fuel reserves amount to 3 billion tons with a share of 88.7 % lignite (high volatile), 10.9 %

brown coal (excluding high volatile lignite) and 0.4 % hard coal (EURACOAL, 2013). Despite increasing CO_2 emissions, the Bulgarian energy strategy paper for reliable, efficient and cleaner energy refers to lignite as primary energy resource for power generation to lower the 70 % import dependency on the Russian Federation and the Ukraine regarding brown coal, natural gas, crude oil and uranium (MEET, 2011b; EURACOAL, 2013). For natural gas, Bulgaria's import dependency on the Russian Federation amounts to 85.4 % (Bulgartransgaz, 2013). Against the background of the Bulgarian energy system's weaknesses related to its CO_2 emission intensity and import reliability, the aim of the present study is to investigate if and to what extent the application of CCS equipped power plants (CCS-PP) and UCG-CCGT-CCS may oblige the situation. Thereby, Bulgaria's prospective of achieving EU environmental targets with and without the two technologies was investigated by modeling current and future energy production output, CO_2 emission and COE for three different scenarios. These are UCG-CCGT-CCS, CCS equipped power plants and a baseline scenario without UCG-CCGT-CCS and CCS-PP (but renewable energy and nuclear power). Another issue assessed in the context of the present economic analysis is the substitution of natural gas imports by the production of natural gas quality UCG synthesis gas and its in-feed into the national gas transport network.

4.1 UCG-CCGT-CCS and CCS-PP Implementation Concept

In order to develop a suitable concept for implementing UCG-CCGT-CCS and CCS equipped power plants into the Bulgarian energy system, a detailed literature research on the Bulgarian energy infrastructure was undertaken. This concerns primarily resources availability, location, age, capacity and technical features of the existing power plants as well as data on the power transmission line system and the gas transport network (Ganev, 2007; Bulgartransgaz, 2013). Since the scope of the present study is to analyze UCG economics for deep lying coal seams, the focus lies on hard coal resources that mainly appear in the Northeast Bulgarian Dobrudzha Coal Deposit (DCD, cf. Figure 4.1). The two largest power plants in the vicinity are Ruse and Varna (cf. Figure 4.1). Both power plants are fueled with imported lignite, because due to complex geological boundary conditions the Dobrudzha Coal Deposit (DCD) is not exploitable via conventional mining (Cleal et al., 2009). In the present study, the commercial-scale scenario setup developed for the selected target area dimensions (cf. Chapter 2.2.4, *UCG Commercial-Scale Setup for the Target Area*) is considered as exploitation scheme for as many coal fields of equal dimensions as required to supply the UCG synthesis gas fueled CCGT power plants. To avoid manipulating the existing power plant capacities and to feed in the produced electricity based on UCG synthesis gas into the transmission line system via existent infeed interfaces, only old or planned power plant stocks were considered for a substitution by UCG-CCGT-CCS.

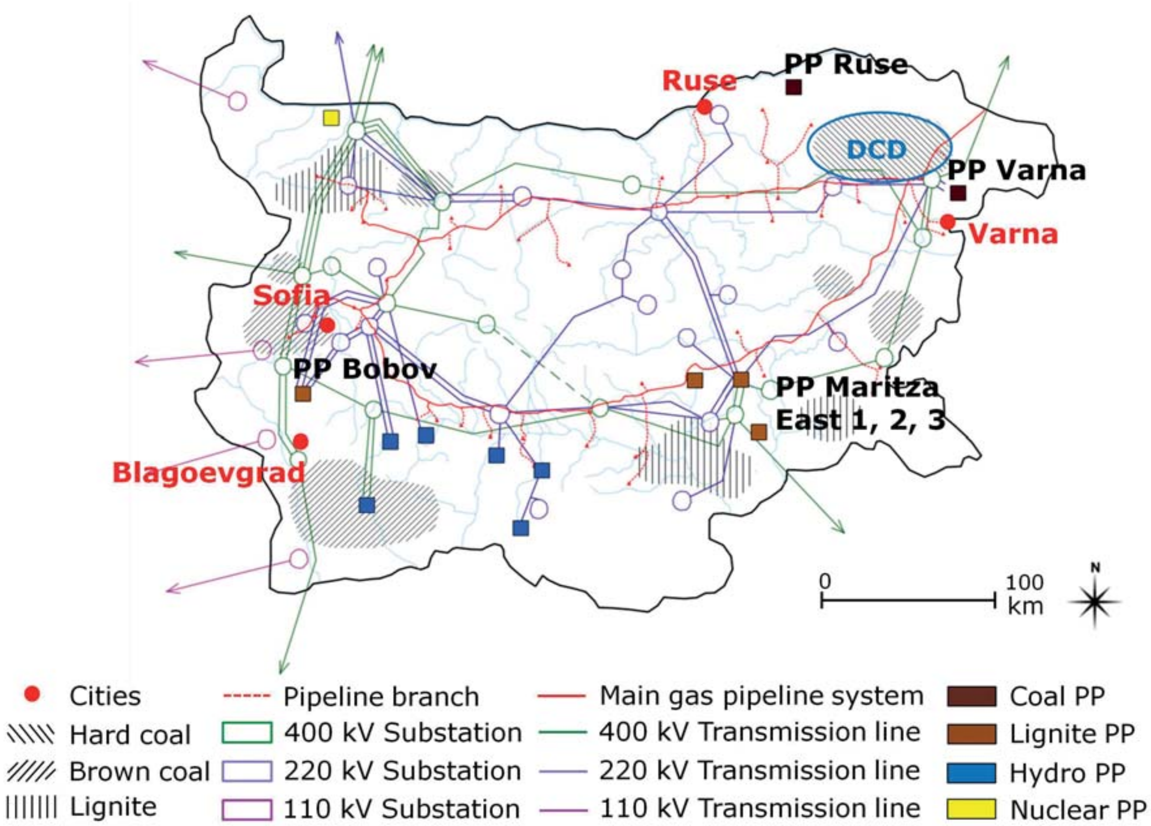

Figure 4.1: Bulgarian coal resources, energy infrastructure and largest power plants (PP), modified from Nakaten et al. (2013).

Power plant Ruse (400 MW_{el}) was built block by block between 1964 and 1984 (Platts, 2009). The World Electric Power Plants (WEPP) database does not list any retirement plans, but assuming an average power plant operational time of according to Konstantin (2009) 40 years, the last block should be retired in 2024. Furthermore, the WEPP database shows that the construction of two natural gas plants (total 580 MW_{el}) and one waste combustion plant (300 MW_{el}) is planned near Varna in 2015. Another aspect to be considered for the UCG-CCGT-CCS implementation strategy is the national gas transport system as none of the nearby power plants is located close enough to the DCD to facilitate an in-situ UCG synthesis gas combustion. Thus, the UCG synthesis gas has to be transported to the respective power plants via the existing gas transmission network grid. A compressor station is located in the Northeast of the Dobrudzha Coal Deposit, where the processed UCG synthesis gas is compressed before its transportation to the accordant power plants. The concept for implementing CCS equipped power plants (CCS-

PP) into the Bulgarian energy system is focused on the power plant age. According to ZEP (2011) CCS technology will be marketable post 2020 hence, only power plants expected to be retired in 2020 were considered to be substituted by modern CCS power plants. Figure 4.1 combines all infrastructural criteria considered for the selection process such as resources availability, the largest power plants and their connection to the transmission line system and the national gas pipeline system.

4.2 Modeling Concept and Applied LEAP Software

The development of electricity production output, resource extraction and CO_2 emissions in the Bulgarian energy sector between 2010 and 2050 was modeled with the software tool for energy policy analysis and climate change mitigation assessment Long Range Energy Alternatives Planning System LEAP (Heaps, 2012). In terms of the modeling methodologies the software supports bottom-up, end-use accounting techniques and top-down macroeconomic modeling with regard to the demand side. Taking into account the supply side, LEAP provides a range of accounting and simulation methodologies for modeling electric power generation and capacity expansion planning. LEAP is not a model of a particular energy system, but a tool that can be used to create models of different energy systems with individual data structures (Heaps, 2012). As depicted in Figure 4.2, the tree data structure exhibits the main module key assumptions (with the branches population and gross domestic product), demand sector (with the branches households, agriculture, industry, public sector and transport), transformation sector (with the branches energy distribution losses and electricity demand) and resources (with the branches export and import). As a starting point for the model setup, the Stockholm Environmental Institute (SEI) provides national level data sets for LEAP. These data sets combine historical energy balance data provided by the IEA, IPCC, United Nations, World Bank, World Resources Institute and the World Energy Council. As a basis for the simulations undertaken in the context of the present study, the respective database for Bulgaria was applied. The reason for selecting the LEAP modeling software is that it allows for the construction of flexible and multivariate models and a straight-forward implementation of external time-varying data (e.g. energy load curves) enabling econometric simulations. According to Pesaran (1987) econometrics is the application of mathematics, statistical methods and computer science to economic data and is described as the branch of economics that aims to give empirical content to economic relations. Additionally, the tool can act as a standard COM Automation Server being controlled by other Windows programs directly, which is important to realize the coupling of the techno-economic model to the power generation modeling process using an application programming interface via an intersection code (cf. Figure 4.2).

In order to model UCG-CCGT-CCS and CCS-PP economics, electricity production output and CO_2 emission produced during electricity production, some model input variables were added to the provided LEAP data set. This pertains primarily the implementation of UCG-CCGT-CCS as a potential electricity generation process into the LEAP tree data structure and its dynamic coupling to the techno-economic model. The CCS equipped power plants were implemented into the LEAP tree data structure in the same way. As the LEAP electricity generation branch is merely class-divided into primary energy carriers, for a more flexible treatment and regulation of planned extensions and retirements in the power plant stock, the electricity generation branch was itemized down to power plant level (cf. Figure 4.2). Thereto, Bulgaria's largest power plants with an installed capacity beyond 100 MW_{el} were embedded as individual process variables into the system (according to the existing power plant stock), whereby power plants with an installed capacity below 100 MW_{el} were merged to one single category. Information on the existing power plants capacity, availability as well as planned retirements and extensions were adapted from available data (Kostova et al., 2005; IEA, 2009; Konstantin, 2009; Lithgow, 2009; Pandelieva, 2009; Swanson, 2009; SEEIM, 2010; Kiriakov et al., 2010; Nitzov et al., 2010; Pashanovska, 2010; IEA, 2011; Zane et al., 2012; Kulovesi et al., 2011; EURELECTRIC, 2012; MEET, 2011a,b; Todorova, 2011; IEA, 2012b; Lefkowitz, 2012; Lozanova, 2012; Ralchev, 2012; SEWRC, 2012; Carma, 2013; Eurostat, 2013; WNA, 2013). Furthermore, the determination of power plant availability and their merit order (order in which the power plants supply the electric power grid) is maintained by an implemented energy load curve (cf. Figure 4.2). The latter one contains load data of the Bulgarian demand-side management, referring to the distribution of energy requirements over time provided in a hourly interval for the reference year 2009 (ENTSOE, 2013). In LEAP, each process embedded in the electricity generation branch is defined by up to 20 variables and basic property rules (electricity export and import, power losses for distribution and own use). Variables that affect electricity production the most are process efficiencies, exogenous and endogenous power plant capacities, maximum availability, merit order and heat rates (the rate of fuel required per unit of energy produced). However, some variables not available but required to calculate e.g. the COE development, had to be implemented supplementary as new classes of variables (cf. Figure 4.2). This concerns e.g. the variables costs of electricity, CCS costs and the power plant emission rate. Thereby, the individual emission rate for every single power plant was considered to calculate CCS costs and CO_2 emission charges and add latter to the related COE values. Cost of electricity and CCS costs for the UCG-CCGT-CCS processes are modeled with the techno-economic model and dynamically coupled (using a programming command) to the LEAP modeling software via an application programming interface (API). The LEAP application programming interface (cf. Figure 4.2) consists of several classes, each with its own properties and methods, whereby properties are values that can be inspected or changed, whereas methods are functions (Heaps, 2012).

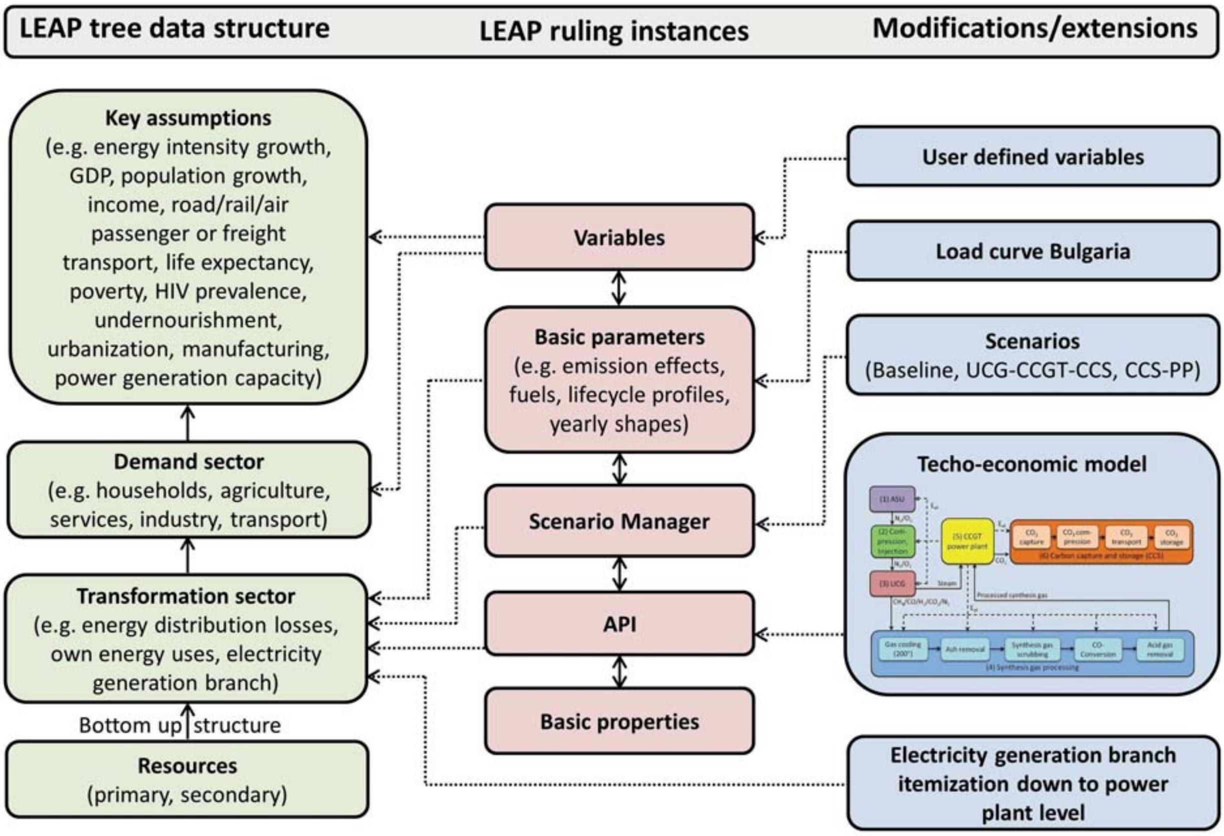

Figure 4.2: Basic LEAP tree data structure with its modifications and extensions.

Besides the implementation of external components into LEAP, the existing data set was revised by more detailed and updated values as enlisted below.

- Energy intensity (MEET, 2011a,b)
- Final energy intensity in the demand sector (MEET, 2011a,b)
- Distribution losses during power generation (IEA, 2009, 2010, 2011, 2012a)
- Energy demand for own use (IEA, 2009, 2011, 2012a)
- Primary and secondary resource imports and costs (MEET, 2011b; EURACOAL, 2013)

4.3 Investigated Scenarios

In order to compare the development of COE and CO_2 emissions taking into account an implementation of UCG-CCGT-CCS or CCS-PP with the simulations considering neither of both transitions technologies, it was necessary to build three modeling scenarios. These are a baseline scenario which does not consider UCG-CCGT-CCS nor CCS-PP but renewable energy and nuclear power supply to meet the national and EU environmental targets, a scenario supposing the implementation of UCG-CCGT-CCS as a low carbon alternative to fossil power generation and a CCS-PP scenario assuming the upgrade of four selected power plants with post-combustion capture and subsequent CO_2 storage. All scenarios investigated are based on statistical data for the historical period (1990 until the first simulation year 2010) provided with the data set.

4.3.1 Baseline Scenario (without UCG-CCGT-CCS and CCS-PP)

The baseline scenario considers neither the production of UCG synthesis gas nor CCS equipped power plants, but nuclear power and the development of the energy sector as it is discussed in the Bulgarian energy strategy paper for reliable, efficient and cleaner energy (MEET, 2011b). As the strategy paper sets precise environmentally related goals until 2020 only, the simulation period 2020 to 2050 relies on the EU environmental targets regarding a share of 50 % regenerative energy in the overall energy mix prevailing for all EU member states (Severin and Westphal, 2012).
In LEAP, basic expectations on the future energy budget development in each sector are further incorporated into the simulations via parameters as basic process assumptions, basic variables and basic property rules. For all power plants, an average operational lifetime of 40 years was assumed. Exceeding this time interval, the corresponding power plants are retired and substituted by power plants of equal installed capacity, availability and geographical location taking into account increased power plant efficiencies due to technological progress. Besides this method of continuation regarding the existing power plant stock in the simulation period, future planned retirements as well as additional capacities mentioned in different sources were embedded into the model setup (Platts, 2009; MEET, 2011b; SEWRC, 2012; WNA, 2013). This refers to the three gas-fueled power plants Ovcha Kupel (300 MW_{el}), Varna (580 MW_{el}) and Haskovo (130 MW_{el}) which will be connected to the grid in 2015 with a respective annual availability of 50 % (Platts, 2009; SEWRC, 2012). Furthermore, MEET (2011b) assumes the extension of nuclear power supply from 2,000 MW to 4,000 MW in 2020. Until 2020, the available

energy potential for hydro-power will be fully exploited. Hence, the simulation setup for 2020 to 2050 considers a yearly growth rate of 0.07 % only (MEET, 2011b). Therefore, the extension of biomass (yearly growth rate of 0.24 % from 2020 until 2050), solar power (yearly growth rate of 0.12 % from 2020 until 2050) and particularly of wind power, which is currently the renewable energy technology with the lowest COE (yearly growth rate of 0.71 % from 2020 until 2050), has to be significantly higher to reach a 50 % share of renewable energy in the overall energy mix in 2050 (ENVIRON, 2010; CWB, 2013). Energy losses for electricity production amount to 16.4 %, to 24 % for heat production, to about 5.4 % in the petroleum industry, to 3.9 % for natural gas and to 15.5 % for coal and coal products (Heaps, 2012). In the simulation period (2010 to 2050), an energy intensity decrease due to technological progress is determined by the basic property rule taking into account an annual energy intensity growth of about 0.9 % (MEET, 2011b). In this study, the energy intensity variable represents the annual energy consumption per unit of activity level (social or economic activity for which energy is consumed) and was determined by taking into account the EU environmental targets regarding an increase of production efficiency by 20 % until 2020 compared to the reference year 1990. Thereby, data until 2010 were available as historical data-set model input (Heaps, 2012). Energy transmission and distribution losses until 2020 amount to 11.6 %, but decrease to 9.2 % until the last simulation year due to planned net extensions (EURELECTRIC, 2012). Because of its strategic geographical location, the balkan peninsula Bulgaria is the largest electricity producer among the South East European countries (besides Romania), supplying the neighbors Montenegro, Greece, Turkey, Macedonia, Romania and Serbia with up to 12 GWh electricity annually (ENTSOE, 2008, 2009, 2010, 2011; Eurostat, 2012). With the expansion of the numerous existing transmission lines, the Bulgarian government aims to increase the electricity export up to 13 TWh (MEET, 2011b). Hence, according to MEET (2011b), in the baseline scenario electricity exports are considered with up to 6.2 TWh in 2015, with 10.4 TWh in 2020 and with 13 TWh for the period 2030 to 2050. Due to insignificant electricity import values, electricity imports are neglected in the current study. In order to analyze the development of COE in the simulation period, average Bulgarian COE for every power plant type were considered (SEWRC, 2012). In the baseline scenario, CO_2 emissions resulting from fossil power generation are released into the atmosphere assuming CO_2 emission charges of 15 €/t CO_2 in the first simulation year up to 44 €/t CO_2 in 2050 (Hohmeyer, 2010). The cost development trend for renewable energy were adapted from Hohmeyer (2010) and predict a COE increase by 1.5 % until 2020, caused by increased investment costs for e.g. capacity and grid network expansions. Once the infrastructure is available, renewable energy COE are expected to decrease by 1.4 % per year. The COE development of the non-renewable electricity production technologies is determined by increasing CO_2 emission charges (excluding nuclear energy) and an average inflation rate of 1.5 % (IEU, 2013).

4.3.2 UCG-CCGT-CCS Scenario

The basic simulation setup for the UCG-CCGT-CCS scenario is identical with the baseline scenario with the exception of two installed UCG-CCGT-CCS power plants. Thus, for the UCG-CCGT-CCS scenario, it is assumed that after its retirement in 2024, power plant Ruse will be replaced by a UCG synthesis gas fueled 400 MW_{el} CCGT power plant with 90 % CCS (UCG-CCGT-CCS Ruse). Instead of connecting two planned gas power plants and one waste plant near Varna to the grid in 2015 in the baseline scenario, the mentioned power plants were replaced by one 880 MW_{el} UCG synthesis gas fueled CCGT plant with 90 % CCS (UCG-CCGT-CCS Varna) in the UCG-CCGT-CCS scenario. The UCG synthesis gas fueled power plant capacities are equal to the respective planned power plants in the baseline scenario, also starting their operational time in the same year and supplying the existing transmission line system. Since the synthesis gas providing UCG plant is taken into account with an availability of 95 % and a steadily use of the produced synthesis gas is considered, the availability of both UCGT-CCGT-CCS power plants is adjusted to 95 %, accordingly.

UCG-CCGT-CCS Varna (57 €/MWh) and UCG-CCGT-CCS Ruse (47 €/MWh) COE in the reference scenario were modeled via the techno-economic model coupled to the LEAP modeling software via an API. Due to expected differences regarding the technological development states in the years of commissioning, different power plant efficiencies were considered (UCG-CCGT-CCS Varna with 46 % and UCG-CCGT-CCS Ruse with 48 %) resulting in different COE. Another reason for COE difference of both UCG-CCGT-CCS power plants is the application of a linear scaling approach fitted to the related plant capacity in order to vary personal, insurance, operational, maintenance and decommissioning costs. Thus, economies of scale effects possibly inducing a COE decrease for UCG-CCGT-CCS Varna do not have any effect at this point. To establish a basis for subsequent economical reference analysis, CCS costs for the UCG-CCGT-CCS power plants and CCS-PP were adapted from ZEP (2011) and charged against the emission rates of the respective power plants. CCS costs range in accordance to the different power plant types from 39 €/t CO_2 to 109 €/t CO_2. With regard to a feasible CO_2 capture rate of 90 %, UCG-CCGT-CCS COE were added by CCS costs charged for 90 % of the produced CO_2 and emission fees charged for 10 % of the emitted CO_2. In this scenario, it was assumed that the separated carbon dioxide is stored in the former UCG voids related to the available storage capacity (20.5 %), whereby the residual amount of separated CO_2 (69.5 % since a capture rate of 90 % was taken into account) is stored in saline aquifers.

4.3.3 CCS-PP Scenario

The CCS-PP scenario simulation setup is identical to the simulation setup developed for the baseline scenario with the exception of four implemented CCS power plants. Until 2020, the fossil power plants Maritza East 1 (670 MW_{el}), Bobov (420 MW_{el}), Varna (580 MW_{el}) and Ruse (400 MW_{el}) will exceed their average power plant operational time which according to Konstantin (2009) amounts to 40 years. For the CCS-PP scenario it was considered that latter are retired and replaced by modern CCS monoethanolamine (MEA) post combustion technology equipped power plants of equal installed capacity from 2020 assuming a CO_2 capture rate of 90 %. CCS costs were adapted from ZEP (2011) and range from 39 €/t CO_2 to 109 €/t CO_2.

4.4 Modeling Results

Aim of the energy modeling undertaken is to ascertain the electricity production output under consideration of all determined boundary conditions for energy sector related branches with particular regard to costs and CO_2 emissions assuming UCG-CCGT-CCS, CCS-PP and a baseline scenario. Based on the historical production which represents representative historical data for the period between 1990 to 2009, the simulation period starts with the first simulation year 2010 and exceeds to 2050.

4.4.1 Electricity Production Output

Considering the intended expansion of electricity export of up to 13 TWh until 2030, as well as growing energy demands (especially in the service sector and households), modeling results indicate an increase of Bulgaria's electricity production output from 41 TWh in 2010 up to 64 TWh in 2050. According to (MEET, 2011b), planned nuclear power supply extensions (by 2 GW in 2020) result in an increased share in the overall energy mix from 36 % in 2009 up to 40 % until 2050 (cf. Figure 4.3). Since the Bulgarian government intends to continue using the high domestic lignite resources for electricity production, lignite fired power plants have a share of 28 % in the energy mix until 2020, whereby their share decreases from 2030 as the contribution of renewable energy increases (MEET, 2011b). For the same reason, from 2030 the share of coal products and natural gas (1.9 % in 2030 and 0 % in 2050) in the energy mix is reduced.

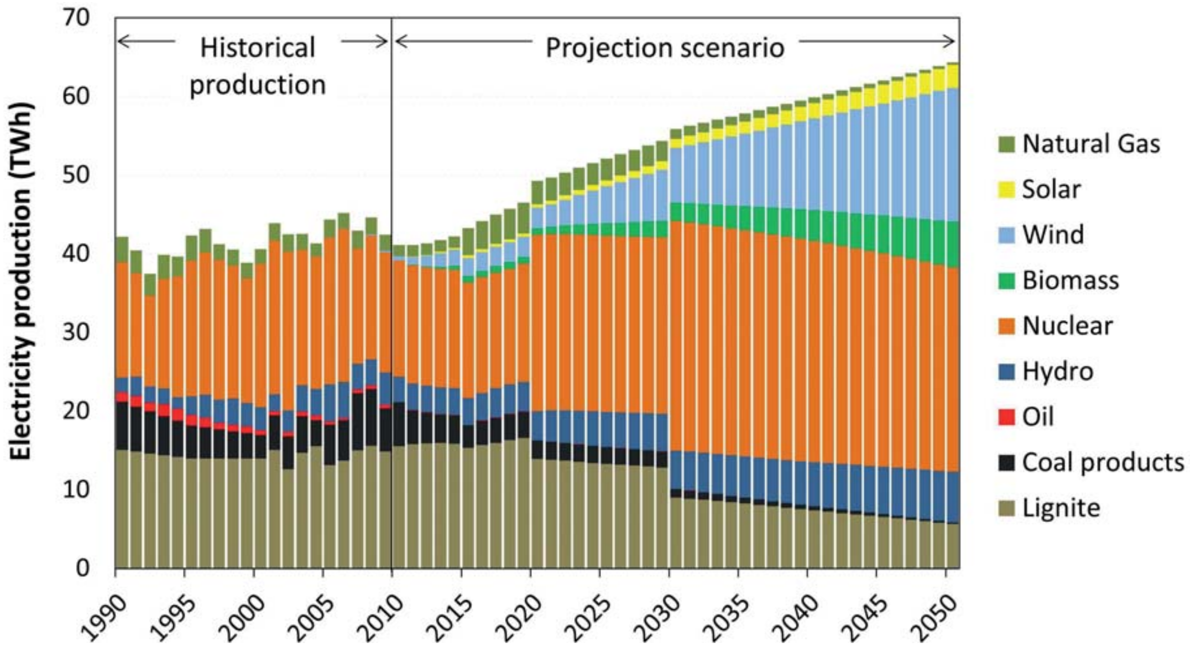

Figure 4.3: Electricity production output in the historical production and in the baseline scenario until 2050, modified from Nakaten et al. (2013).

Electricity production from oil products had a negligible part in the energy mix since the beginning of 2000 (2.4 % in 2004, 0 % in 2010 and beyond). From 2020 hydro power will increase insignificantly as the available capacity is already fully exploited. However, taking into account the EU environmental targets respecting a 50 % share of renewable energy in 2050, simulation results show that growth for solar power (1.6 % in 2030 and 4.7 % in 2050), biomass (3.7 % in 2030 and 9.4 % in 2050) and especially for wind power (6.1 % in 2030, 26.6 % in 2050) has to be significant to reach this goal. Figure 4.3 shows the electricity supply for the baseline scenario. Nevertheless, electricity production output in the UCG-CCGT-CCS and CCS-PP scenario results show insignificant differences only, since identical power plant capacities and availabilities were taken into account. Although UCG and CCS implementation causes efficiency decreases of up to 12 %, it does not impact LEAP modeling results regarding the electricity production output but the required fuel (resources) and resulting emissions, only. However, due to the high availability of the UCGT-CCGT-CCS power plants electricity supply is slightly higher (355 GWh) than in the other scenarios.

4.4.2 CO_2 Emissions

CO_2 emissions in the historical production and for the simulation period in the baseline, UCG-CCGT-CCS and CCS-PP scenarios is visualized in Figure 4.4. The three scenarios have in common, that CO_2 emissions decrease continuously, since nuclear power and renewable energy have an increasing share in the overall energy mix.

The increase of CO_2 emissions in the baseline scenario between 2015 and 2020 is caused by the increased electricity production output based on fossil fuels, as three additionally natural gas power plants (Ovcha Kupel, Varna, Haskovo) will be implemented in 2015 (Platts, 2009). However, additional 2 GW nuclear power capacities connected to the grid in 2020 as well as a decrease of fossil fueled power generation in 2020 reduce CO_2 production (MEET, 2011b). Figure 4.4 depicts equal CO_2 emission trends in the CCS-PP and baseline scenario until 2020. However, after CCS implementation CO_2 mitigation in the CCS-PP scenario is up to 10.2 Mt higher than in the baseline scenario. CO_2 emissions in the UCG-CCGT-CCS scenario develop equally to the CCS-PP and baseline scenarios until UCG-CCGT-CCS Varna starts its operation in 2015, obtaining a CO_2 emission reduction of 5.2 Mt compared to the baseline scenario.

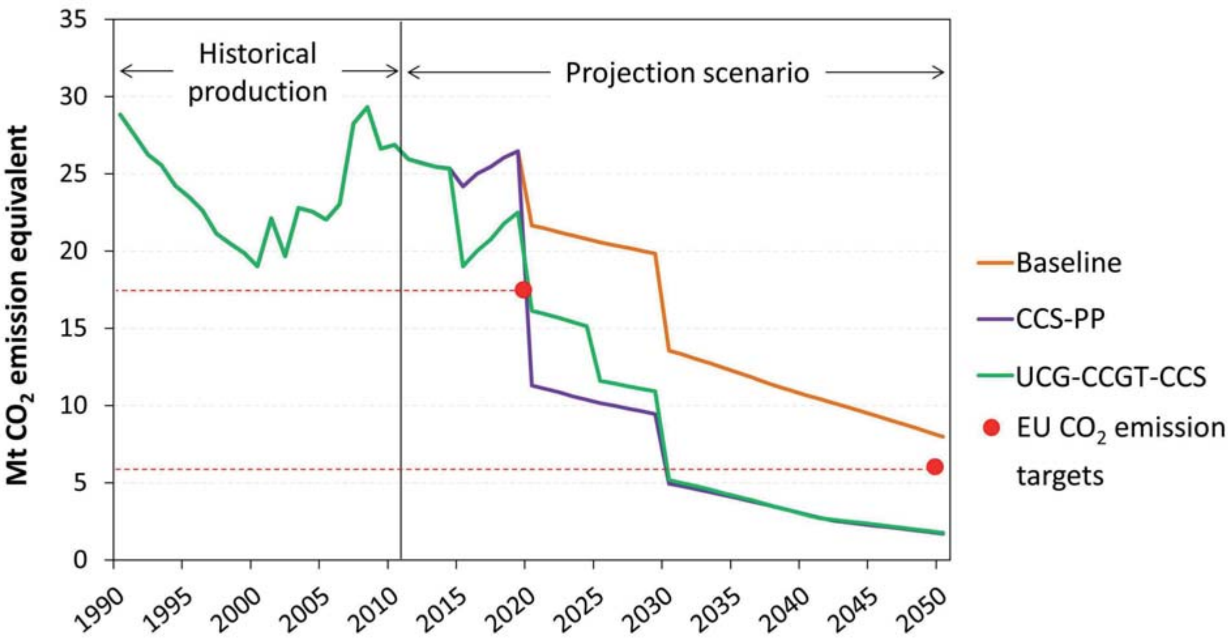

Figure 4.4: CO_2 emissions in the UCG-CCGT-CCS, CCS-PP and baseline scenarios, modified from Nakaten et al. (2013).

The CO_2 emission increase between 2015 and 2020 is attributable to a higher electricity production output based on three additional natural gas power plants, whereof two (Ovcha Kupel, Haskovo) are not equipped with CCS. The third gas power plant is UCG-CCGT-CCS Varna assuming 95 % availability and 90 % CCS. Due to additional nuclear power capacities and a decreasing share of fossil fuel power, CO_2 emissions decrease by 0.6 Mt from 2020 until 2024. The significant CO_2 emission decrease in 2025 is due to the implementation of UCG-CCGT-CCS Ruse with 95 % availability and 90 % CCS (cf. Figure 4.4). Subsequently, CO_2 emissions drop continuously as a result of a high share of nuclear power, renewable energy and UCG-CCGT-CCS. The third phase of the three-phase CO_2 certificate trading program (Phase 1: 2005 to 2007, Phase 2: 2008 to 2012, Phase 3: 2013 to 2020) passed the European Parliament in 2003 and was put into force in 2005. According to the third program phase each EU member state has to reduce CO_2 emissions by 21 % compared to a national specific selected reference year, instead of the previous national specific emission limits related to 2020. For Bulgaria, the reference year was chosen to be 2005. However, for 2020 Bulgaria has an individual commitment allowing for an emission reduction by 20 % compared to their 2005 level (BMU, 2009; EC, 2010; Kodzhabashev, 2012). Gaining these environmental targets of carbon dioxide emission decrease of 20 % compared to 2005 until 2020 and to 1990 by 80 % until 2050, CO_2 emissions in the Bulgarian energy sector should not exceed 17.6 Mt in 2020 and 5.8 Mt in 2050. Comparing these requirements with simulation results obtained for CO_2 emission development in the baseline scenario, the aims will be neither achieved in 2020 nor in 2050. CO_2 emissions even increase by 1.8 % until 2020 due to additional gas power plants implemented in 2015. Despite the share of 50 % renewable technologies in the overall energy mix in 2050, CO_2 emissions exceed the permitted value by 7.8 %. With regard to the UCG-CCGT-CCS and CCS-PP scenarios, the EU environmental targets are achieved for 2020 and 2050.

According to Esken et al. (2010), the CO_2 storage potential in Bulgarian saline aquifers amounts to 2.12 Gt. Assuming a CO_2 capture rate of 90 % and an operational lifetime (until the last simulation year) of 35 years for UCG-CCGT-CCS Varna and 30 years for UCG-CCGT-CCS Ruse, 265 Mt CO_2 in total (resulting from UCG and power generation) will be mitigated in the UCG-CCGT-CCS scenario (compared to the baseline scenario). Related to the storage capacity of 20.5 %, 54 Mt CO_2 (captured during the simulation period) will be stored in the former UCG voids. Hence, the remaining 210 Mt CO_2 will be stored in the Bulgarian saline aquifers. CO_2 mitigation in the CCS-PP scenario amounts to 290 Mt CO_2, taking into account a capture rate of 90 % and a CCS power plant operational lifetime until the last simulation year (30 years). Thus, the available storage potential in the domestic saline aquifers is completely sufficient to store the amount of captured CO_2 during the simulation period.

4.4.3 Costs of Electricity

COE and CCS costs development significantly determined by market-dependent parameters such as CO_2 emission charges and cost savings due to technological progress (e.g. efficiency increase resulting in decreasing energy input). To demonstrate the impact of these cost positions on the overall result, COE modeling was undertaken considering low emission charges and no CCS technological progress on the one hand, as well as high CO_2 emission charges and CCS technological progress on the other hand. Since according to ZEP (2011) CO_2 capture costs correlate with CO_2 concentrations in the power plant flue gas (lower CO_2 concentrations elaborate and complicate the capture process resulting in increased CCS costs), CCS costs for the different power plant types vary significantly (e.g. natural gas flue gas has about half the CO_2 content compared to coal flue gas). Accordingly, CCS costs adapted from ZEP (2011) were assigned to the corresponding power plant types to calculate the individual power plant CO_2 emission rates (cf. Table 4.1). For CCS power plant Varna (assuming medium fuel costs) CCS costs account to 65.9 €/t CO_2, to 38.9 €/t CO_2 for the CCS lignite and coal power plants Maritza East 1, Bobov, Ruse and to 29.9 €/t CO_2 for the UCG-CCGT-CCS plants Ruse and Varna. Values for UCG-CCGT-CCS plants Ruse and Varna were adapted from CCS costs provided for integrated gasification combined cycle (IGCC) power plants, since compared to UCG-CCGT-CCS, IGCC systems produce higher CO_2 amounts resulting from electricity generation and the integrated gasification process (the other fossil fueled power plant emission rates consider CO_2 production during the electricity generation, only).

Table 4.1: Emission rates of Bulgarian fossil fueled power plants according to Lithgow (2009), IEA (2012b) and Carma (2013).

Power plant	Emission rate (g/kWh)
Maritsa Istok 1	1.370
Maritsa Istok 2	1.200
Maritsa Istok 3	1.400
Maritsa 3	1.340
Bobov Dol	1.320
Varna	1.010
Ruse	1.200
Oil power plants (averaged)	699
Natural gas power plants (averaged)	299

IGCC processes consider the pre-combustion capture technology, whereby the post-combustion capture technology was taken into account for the UCG-CCGT-CCS power plants. Nevertheless, CCS cost differences as a result of different emission rates (up to 36 €/t CO_2) are higher than cost differences between the pre-combustion and post-combustion capture technologies (up to 8 €/t CO_2). Thus, taking into account IGCC CCS costs for the UCG-CCGT-CCS process results in lower cost differences (up to 8 €/t CO_2 because of different technologies) than it would be the case considering CCS costs related to a power plant with a different emission rate (up to 36 €/t CO_2).

Low CO_2 Emission Charges Without CCS Technological Progress

For the conservative COE modeling setup, low and slightly increasing CO_2 emission charges (15 €/t CO_2 in 2015 to 44 €/t CO_2 in 2050) without CCS technological progress were taken into account. Figure 4.5 shows, that throughout the simulation period nuclear power achieves significantly lower COE (22 €/MWh in 2010 to 40 €/MWh in 2050) than averaged fossil power plants (64 €/MWh in 2010 to 132 €/MWh in 2050) or averaged renewable energy production technologies (89 €/MWh in 2010, 103 €/MWh in 2020, 73 €/MWh in 2050).

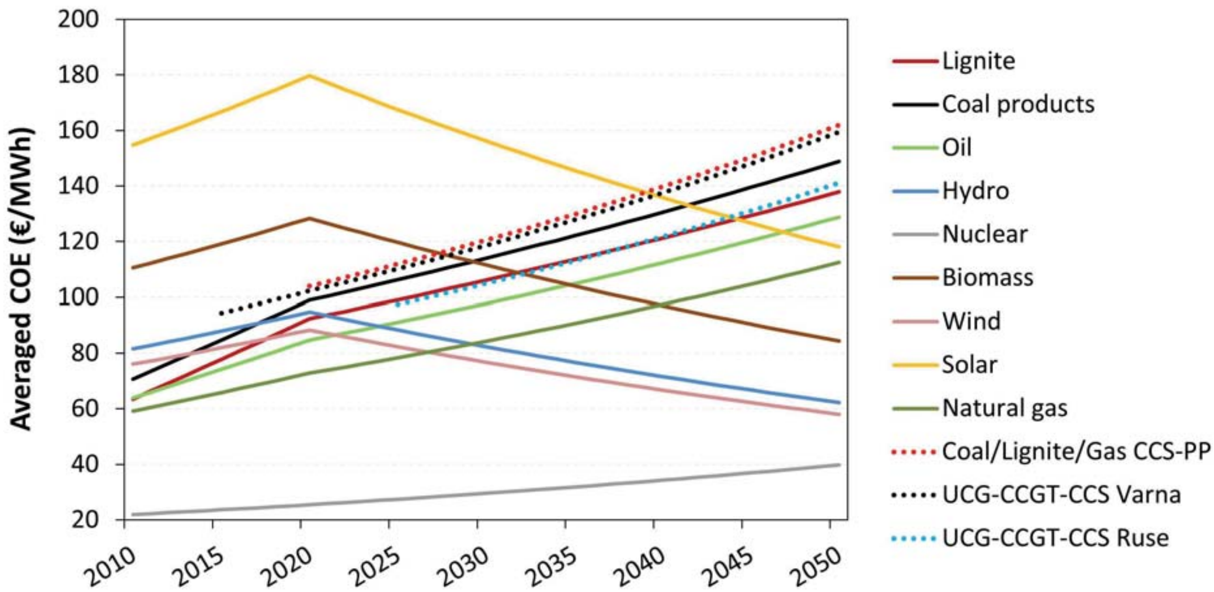

Figure 4.5: Bulgarian COE with slightly increasing CO_2 emission charges and CCS costs (without cost reduction due to CCS technological progress), modified from Nakaten et al. (2013).

Until 2020, electricity production from solar power achieves the highest COE (180 €/MWh) amongst all Bulgarian electricity production technologies. However, until 2050 solar power COE will be lower than averaged fossil power COE by 14 €/MWh. Wind power COE are about 79 €/MWh lower than solar power COE, whereby according to the simulation results between 2020 and 2050 wind power becomes the cheapest energy production technology besides nuclear power (79 €/MWh lower than averaged fossil power COE). Averaged UCG-CCGT-CCS COE exceed averaged fossil power COE by 22 €/MWh, whereby CCS-PP COE surpass averaged UCG-CCGT-CCS COE by 2 €/MWh. Comparing UCG-CCGT-CCS COE with other Bulgarian energy production technology COE in the conservative modeling setup, UCG-CCGT-CCS Ruse is competitive with lignite and other coal products fueled power plants. Nevertheless, taking into account the assumed market-dependent boundary conditions of the underlying case, UCG-CCGT-CCS Varna and CCS-PP COE exceed other fossil fuel energy production COE. The increase (1.5 %) of renewable energy COE until 2020 is caused by increased investment costs for e.g. capacity and grid network expansions. Thereafter (once the infrastructure is available), renewable energy COE are expected to decrease by 1.4 % (cf. Chapter 4.3.1, *Baseline Scenario*).

High CO_2 Emission Charges With CCS Technological Progress

Taking into account higher CO_2 emission charges (20 €/t CO_2 in 2010, 40 €/t CO_2 in 2023, 60 €/t CO_2 in 2038 and 80 €/t CO_2 in 2050) and an according to ZEP (2011) prospective technological efficiency increase of three percent points causing a post-combustion capture cost decrease by 3.2 €/t CO_2, UCG-CCGT-CCS and CCS-PP COE can compete with averaged fossil power plants COE (without CCS but CO_2 emission charges). As pictured in Figure 4.6, after 2020 CCS-PP COE become more economic than averaged coal fired power plants COE without CCS but CO_2 emission charges. After 2025, CCS-PP COE and UCG-CCGT-CCS Varna become more economic (25 €/MWh in average) than electricity production by Bulgarian coal and lignite fueled power plants. Until 2050, UCG-CCGT-CCS Ruse COE are up to 11.3 €/MWh lower than oil fueled power plants COE. Comparing both modeling cases (low CO_2 emission charges without CCS technological progress, high CO_2 emission charges and CCS technological progress) demonstrates that the future competitiveness of avoiding CO_2 emissions by applying CCS depends on the marked price development for CO_2 emission charges and the technological state of the utilized CO_2 capture plants.

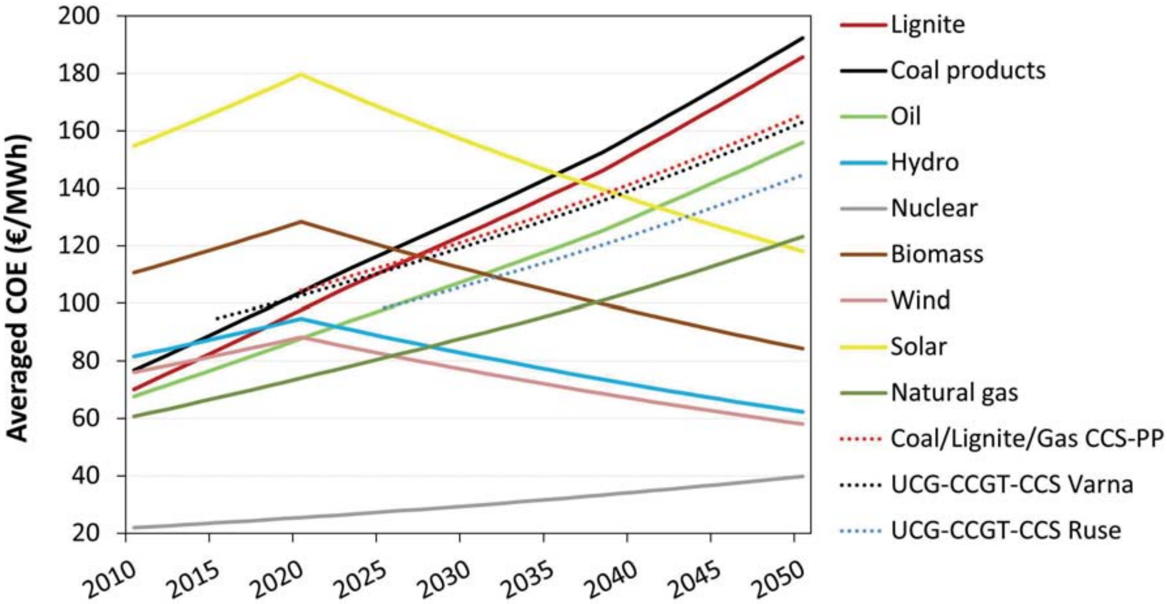

Figure 4.6: Bulgarian COE with rapid increasing CO_2 emission charges and CCS costs (with cost reduction due to CCS technological progress).

4.4.4 UCG Synthesis Gas as Natural Gas Substitute

Feeding upgraded UCG synthesis gas directly into the Bulgarian gas pipeline network avoiding its conversion into electricity is an alternative approach for UCG synthesis gas utilization with relevant economic potentials. Assuming a UCG plant availability of 95 % and a coal consumption as it was assumed for electricity production (UCG-CCGT-CCS Varna 8,605 t coal/day and UCG-CCGT-CCS Ruse 3,764 t coal/day), a yearly amount of 12.35 billion sm^3 UCG synthesis gas can be provided. This would lower Bulgaria's gas import reliability by 100 %, since according Bulgartransgaz (2013) the increasing yearly import amounts up to 3.1 billion sm^3. Another advantage of substituting natural gas imports by UCG synthesis gas production is that producing 1 GJ UCG synthesis gas is more economic (6 €/GJ) than the import of 1 GJ natural gas (6.4 €/GJ in 2015 and 11.2 €/GJ in 2030; (MEET, 2011b)). The obtained results indicate that the Bulgarian energy system can significantly benefit from the implementation of UCG considering CO_2 mitigation technologies potentially initiating a continuous substitution of imported fuels by domestic coal resources.

4.4.5 Impact of Energy Intensity on power production and CO_2 emissions

Besides the EU environmental targets relating to the share of renewable energy in the final energy consumption as well as the reduction of greenhouse gas emissions and import dependency, the increase of production efficiency decreasing energy intensity (energy consumption per unit of activity level) is an important contribution to achieve the EU objectives. In the present study, the variability of energy intensity impact on the energy production output and carbon dioxide emissions was examined in the context of a scenario analysis taking into account a confidence level of different energy intensities in the demand sector. In order to quantify the impact of varying energy intensities in the demand sector, a medium energy intensity growth (MEIG), a low energy intensity growth (LEIG) and a high energy intensity growth (HEIG) for the baseline, UCG-CCGT-CCS and CCS-PP scenarios was considered. Considering the EU targets aiming at a production efficiency increase by 20 % until 2020 compared to 1990, the annual energy intensity in the MEIG case amounts to 0.9 % (EU, 2009). Since there are no detailed goals concerning the energy intensity after 2020, the annual growth rate of 0.9 % was taken into account until the last simulation year. Taking into account an energy intensity investigation bandwidth of 1 %, the energy intensity in the LEIG case was assumed with 0.4 % and with 1.4 % in the HEIG case. In order to illustrate the importance of technological progress, energy intensity in the HEIG case was intentionally overestimated to demonstrate the effect of low production efficiency due to an outdated technology standard. The impact of varying energy intensities on the electricity production output and the CO_2 emissions is visualized in Figures 4.7 and 4.8.

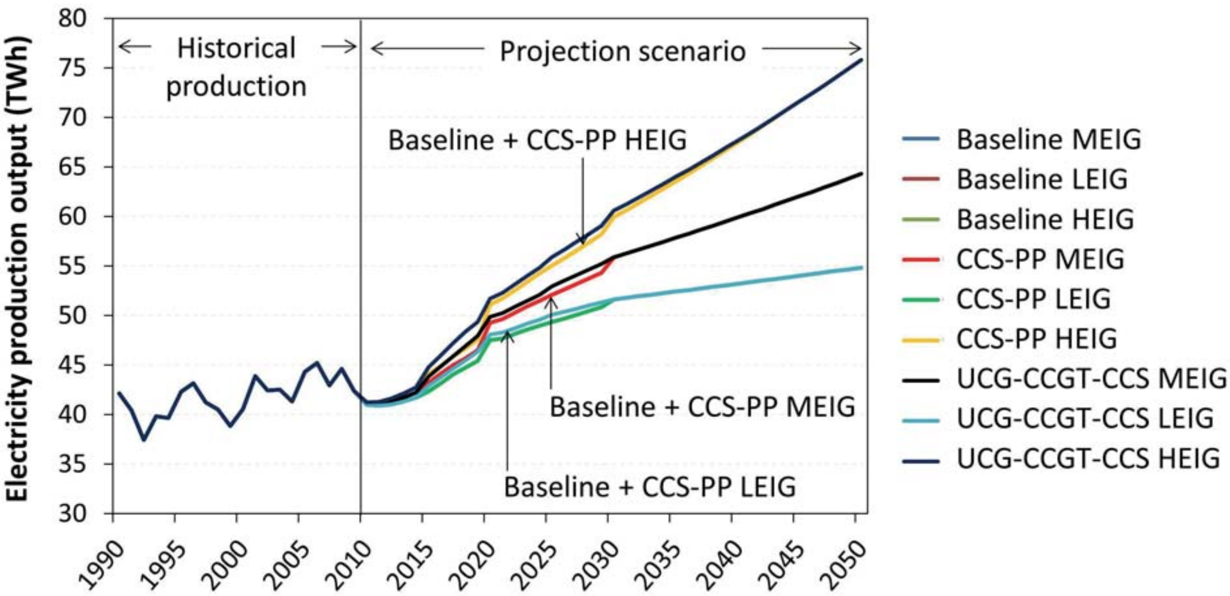

Figure 4.7: Electricity production output in case of LEIG, MEIG and HEIG for the baseline, UCG-CCGT-CCS and CCS-PP scenarios, modified from Nakaten et al. (2013).

In 2050, a 1 % variation in energy intensity from the LEIG to HEIG case causes an electricity production output increase by 21 TWh (cf. Figure 4.7). This high margin results from different input yields, and thus different requirements for primary energy carriers. A high energy intensity per unit of activity level increases the required fuel input, since the input yield is lower than in case of a low energy intensity. The higher the energy intensity, the more resources are required to satisfy the domestic energy demand. Figure 4.8 shows the effect of different energy intensities on CO_2 emissions.

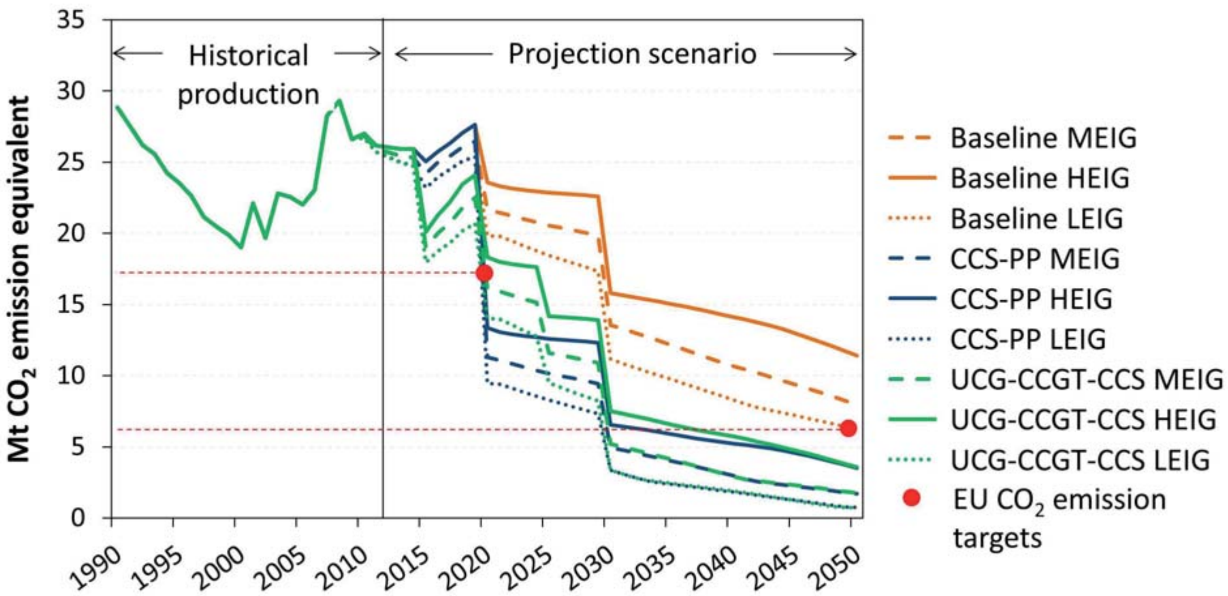

Figure 4.8: CO_2 emissions taking into account LEIG, MEIG and HEIG in the baseline, UCG-CCGT-CCS, CCS-PP scenarios, modified from Nakaten et al. (2013).

Varying energy intensity growth in the baseline scenario by 1 % causes a CO_2 emission variation of about 3.8 Mt CO_2 (16 %) in 2020 and 5.2 Mt CO_2 (46 %) in 2050. Nevertheless, the EU guideline on CO_2 mitigation is neither achieved in 2020 (in comparison to 2005 emissions increase by 7.3 %) nor in 2050 (emission reduction goals are missed by 19.6 %), if the energy intensity is high. However, in the CCS-PP scenario the EU target is achieved in 2020 as well as in 2050. In 2020, the UCG-CCGT-CCS scenario fails the EU target (max. 17.6 Mt CO_2) by 3.2 % (cf. Figure 4.8). Nevertheless, in 2050 this goal is achieved. In line with a low energy intensity, the EU environmental target for 2050 (max. 5.8 Mt emitted CO_2) is achieved in the UCG-CCGT-CCS scenario as well as in the CCS-PP scenario, whereby in the baseline scenario the EU target is missed by 10 % in 2020 and by 1.5 % in 2050.

4.5 Discussion

The undertaken investigation on a potential implementation of UCG-CCGT-CCS and CCS-PP into the Bulgarian energy system revealed that these technologies could play an important role in terms of achieving the EU environmental targets on CO_2 mitigation and decreasing primary energy import dependency. The proposed UCG-CCGT-CCS and CCS-PP implementation concept shows that with regard to infrastructural, technical and geological boundary conditions examined in this study, an embedding of both technologies into the Bulgarian energy system is economically and practically feasible. LEAP simulations on electricity production output and associated CO_2 emissions are based on the Bulgarian energy strategy paper for reliable, efficient and cleaner energy until 2020 and were linearly interpolated to 2050, taking into account that the EU guideline regarding the required share of renewable energy in the overall energy mix is realized. However, despite a 50 % share of renewable energy and a high share of nuclear power in the overall energy mix, simulation results show that the EU environmental target on CO_2 mitigation is not achieved in the baseline scenario, but is achieved in the UCG-CCGT-CCS and CCS-PP scenarios. Furthermore, simulation results show that both scenarios can economically compete with other Bulgarian fossil power generation technologies (without CCS but CO_2 emission charges) taking into account high CO_2 emission charges (20 €/t CO_2 in 2010, 40 €/t CO_2 in 2023, 60 €/t CO_2 in 2038 and 80 €/t CO_2 in 2050) according to ZEP (2011) and a total CCS costs decrease by 3.2 €/t CO_2 due to technological progress.

However, besides the application of CO_2 capture, EU environmental targets focus various strategies to achieve the required greenhouse gas emissions mitigation, e.g. an increase of production efficiency (a low energy intensity per unit of activity level). Comparing energy production output and CO_2 emissions under consideration of low, medium and high energy intensity growth scenarios, simulation results demonstrate the significant impact of decreasing energy intensity in the demand sector (e.g. households, transport sector). Considering a low energy intensity in the baseline scenario (no UCG-CCGT-CCS or CCS-PP), the EU targets are only barely missed (0.43 Mt CO_2), while being amply missed (5.63 Mt CO_2) in the high energy intensity scenario. In summary, LEAP simulation results for the baseline scenario show that without UCG-CCGT-CCS or CCS-PP Bulgaria will not achieve the EU environmental targets on CO_2 mitigation, despite taking into account a low energy intensity and a share of 50 % renewable energy in 2050. Further results reveal, that UCG-CCGT-CCS and CCS-PP are not only essential but also economic alternatives to Bulgarian fossil fuel power generation and that UCG synthesis gas is an economic option to decrease Bulgaria's natural gas import reliability by 100 %.

5 Summary, Conclusions and Outlook

The results elaborated in the present thesis show that underground coal gasification (UCG) coupled to a combined cycle gas turbine (CCGT) with carbon capture and storage (CCS) as well as CCS equipped power plants (CCS-PP) provide economic alternatives to the conventional Bulgarian fossil fueled power generation. Furthermore, natural gas imports could be substituted by 100 % by feeding UCG synthesis gas into the national gas pipeline network. Thus, UCG combined with CCS could be an emission neutral and economic competitive option of making available fossil resources not exploitable by conventional mining. Consequently, UCG-CCS provides a solution to decarbonize the Bulgarian energy system until a renewable energy supply is fully implemented.

5.1 Overview of Elaborated Results

A techno-economic model is developed to analyze the economics of a coupled UCG-CCGT-CCS process consisting of the sub-models air separation for oxidizer production, oxidizer compression and injection, the UCG process, synthesis gas processing, power generation and CCS. CO_2 produced during UCG and subsequent processes is captured and stored in the voids resulting from UCG coal consumption (cf. Chapter 2, *Techno-Economic Model for UCG-CCGT-CCS COE Determination*). According to the available CO_2 storage capacity in the UCG voids, around 21 % of the produced CO_2 can be stored. The excessive carbon dioxide is released into the atmosphere and CO_2 emission charges are payed. The techno-economic model is applicable for any study area world-wide taking into account site-specific geological (e.g. coal seam depth, thickness, coal CV_{Coal}), chemical (synthesis gas composition), technical (e.g. power plant efficiency) and market-dependent (e.g. drilling costs, oxidizer production costs, synthesis gas processing costs) model constraints.

In the context of the present thesis, the developed techno-economic model is applied to assess UCG-CCGT-CCS economics for a selected target area in Bulgaria. Geological model constraints and drilling costs are taken from the UCG&CO_2STORAGE project, whereby internal project data are anonymized (OVERGAS, 2013). In order to provide the required coal to fuel an integrated CCGT power plant for a 20 years lifetime, four target coal seams in a depth range of 1,411 m to 1,800 m are selected for exploitation using UCG. Aiming at an optimized operational process design for target coal seam exploitation, a commercial-scale scenario is developed taking into account surface infrastructure (e.g. compressors, pumps), UCG related processes (piping, measuring, control equipment, etc.) and particularly the well layout. Thereby, the implementation of an algorithm for iterative well head and bottom-hole pressure calculations (considering pressure losses due to frictional forces during injection and production) is an elementary component for the elaboration of an optimized well layout. This algorithm considers required compressibilities and densities according to Kunz and Wagner (2012) as well as pressure- and temperature-dependent viscosity for single gases and their mixtures after Chung et al. (1988). Calculation results show, that based on inner liner diameters of about 8.9 cm (3.5"), the required well head pressure for oxidizer injection varies from 14.9 MPa to 16.5 MPa (in accordance to the respective coal seam of 1,411 m to 1,800 m) and from 6.3 MPa to 7.9 MPa in case of CO_2 injection. Calculated pressure losses with up 0.1 MPa during CO_2 injection and 0.4 MPa during oxidizer injection are considered to be in an acceptable range for the chosen liner diameters and well dimensions. During the entire operational time of 20 years eight injection wells, 95 gasification channels and four production wells have to be drilled. Applying the proposed well layout, a total coal yield of about 45 % can be achieved. In the current study, all cost positions related to the UCG synthesis gas production such as land acquisition, fees, piping, measuring, control equipment (323.1 M€), drilling (235.5 M€), synthesis gas processing (246.5 M€ for 20 years) as well as oxidizer compression and injection (1.1 bn€ for 20 years) are combined as fuel costs. Taking into account the yearly CCGT power plant fuel consumption of 19.3 PJ, levelized fuel costs amount to 5 €/GJ. Averaged costs for electricity production based on UCG synthesis gas account to 48.6 €/MWh and 71.7 €/MWh including costs for CO_2 emission handling.

In order to further assess statistical uncertainties and quantify COE sensitivity related to 14 selected model input parameters, one-at-a-time (OAT) and multivariate sensitivity analyses are undertaken. Aim of the OAT sensitivity analysis is to quantify the range in COE outcomes caused by the variation of one model input parameter across a deduced range of uncertainty to e.g. assess which process step of the coupled UCG-CCGT-CCS system requires particular optimization. As a supplementary measure, a multivariate sensitivity analysis is performed to quantify the overall model constraints related COE uncertainty bandwidth (important for e.g. project planning activities, target area selection) by varying all model boundary conditions simultaneously. Thereto, the respective assumed best-or worst-case conditions for parameters previously assessed within the OAT sensitivity analysis, are combined to one worst- and one best-case scenario. The model boundary conditions selected for investigation consist of geological (seam depth, seam thickness, seam extent, seam thickness to cavity width ratio, daily progress of the gasification front, coal CV_{Coal}), chemical (synthesis gas composition), technical (UCG and CCGT annual operating hours, CCGT power plant efficiency) and market-dependent model input parameters (drilling costs, synthesis gas processing costs, nominal interest rate CCGT power plant, oxidizer production and injection costs, CO_2 emission charges). Parameters associated with high uncertainty due to lack of data (e.g. synthesis gas processing costs, oxidizer production costs) and parameters known to have a relevant impact on UCG-CCGT-CCS COE (e.g. power plant efficiency) are investigated taking into account a variability of ±25 % (compared to the reference scenario). Parameters related to the geologically well explored target area (e.g. coal CV_{Coal}, coal seam thickness and extent) or available literature data are associated with lower uncertainty. In this case, a variability of ±10 % is chosen. OAT sensitivity analysis results show that with regard to the assessed parameter variation bandwidths, geological model boundary conditions cause a COE variation bandwidth of minimum 0.4 % (0.6 €/MWh) regarding the seam thickness and maximum 3.9 % (5.4 €/MWh) regarding the coal calorific value. Taking into account different quality level synthesis gas compositions causes a COE variation bandwidth of 13.3 % (18.6 €/MWh). Varying technical boundary conditions in the deduced bandwidth results in a COE margin of minimum 8.3 % (11.6 €/MWh) with regard to the operating hours and maximum 16.9 % (23.5 €/MWh) regarding the CCGT power plant efficiency. Market-dependent model constraints variation results in a COE margin of minimum 1.7 % (2.4 €/MWh) regarding drilling costs and maximum 25.2 % (35.1 €/MWh) with regard to the CO_2 emission charges. The assessment on the impact of combined parameter changes on COE in the context of a multivariate sensitivity analysis shows that the COE differences between the assessed worst- and best-case conditions amount to 104 €/MWh. Hereby, the multivariate sensitivity analysis refers to the variables taken into account for the OAT sensitivity analysis.

To assess whether UCG-CCGT-CCS is a reasonable improvement to Bulgarian fossil fueled power generation, local scale site-specific economic analysis results presented in Chapter 2 (*Techno-Economic Model for UCG-CCGT-CCS COE Determination*) must be complemented by taking into account UCG-CCGT-CCS geographical and economic potentials or limitations at a national scale. Hence, in the context of the overall Bulgarian energy system. For an analysis of UCG-CCGT-CCS competitiveness, it is important to consider national characteristics such as resource availability, the overall power generation system, the national transmission network

infrastructure as well as other Bulgarian electricity production technology COE. This also includes CO_2 emissions resulting from electricity production.
In the present study, the macro scale UCG-CCGT-CCS competitiveness analysis is realized by implementing an interface of the techno-economic model developed to investigate UCG-CCGT-CCS economics at a local scale and the macro scale energy system-modeling framework LEAP (Heaps, 2012). To elaborate a suitable implementation concept for UCG-CCGT-CCS and CCS equipped power plants (CCS-PP) into the national energy system, a literature research on the Bulgarian resources availability and energy infrastructure (location, age, capacity and technical features of the existing power plants, power transmission line system and gas transport network) is carried out. Literature data reveal, that throughout Bulgaria the Dobrudzha Coal Deposit provides the best infrastructural site-related factors for implementing UCG-CCGT-CCS in otherwise not mineable coal seams. To compare COE and CO_2 emissions produced during power generation taking into account UCG-CCGT-CCS, CCS-PP or a baseline scenario without UCG-CCGT-CCS and CCS-PP but renewable energy and nuclear power supply, three LEAP scenarios are build. The baseline scenario considers neither CCS equipped power plants nor the production of UCG products, but the national and EU environmental targets aiming at a 50 % share of renewable energy in the national energy mix until 2050. The basic setup for the UCG-CCGT-CCS scenario is identical with the baseline scenario, with exception of replacing the power plants Varna and Ruse by two UCG-CCGT-CCS power plants in 2015 and 2025, respectively. The basic setups of the CCS-PP and the baseline scenarios are identical with the difference, that in the CCS-PP scenario the four Bulgarian fossil power plants Maritza East 1, Bobov, Varna and Ruse are replaced by modern CCS equipped power plants of equal capacity in 2020. Taking into account the intended expansion of electricity export up to 13 TWh until 2030 and growing energy demands in the service sector and households, modeling results show an increase of Bulgaria's electricity production output from 41 TWh in 2010 up to 64 TWh in 2050. Simulation results on CO_2 production during electricity production in the baseline scenario show, that the EU emission targets (max. 17.6 Mt CO_2 in 2020 and 5.8 Mt CO_2 in 2050) will not be achieved neither in 2020 nor in 2050 (CO_2 emissions exceed the allowed values by 18.2 % in 2020 and by 7.8 % in 2050). However, compared to the baseline scenario the aims are achieved in the CCS-PP and UCG-CCGT-CCS scenarios. Since the development of CO_2 emission charges and CCS technological progress impact UCG-CCGT-CCS and CCS-PP economics, two cases are assessed. In one case low CO_2 emission charges of up to 44 €/t CO_2 in 2050 without CCS technological progress are assumed. For the second case, high CO_2 emission charges of up to 80 €/t CO_2 in 2050 with CCS technological progress are taken into account. In

the first case, UCG-CCGT-CCS and CCS-PP COE are in average 51 €/MWh below solar and biomass power plants COE in 2020, but slightly exceed other Bulgarian power generation technologies COE in 2050 (with exception of UCG-CCGT-CCS Ruse COE being 8 €/MWh below coal fired power plants COE). Considering high CO_2 emission charges and CCS technological progress, UCG-CCGT-CCS and CCS-PP COE are competitive compared to other fossil fueled power plants COE being 30-33 €/MWh below lignite and coal fired power plants COE.
An economic investigation on substituting natural gas imports by feeding natural gas quality UCG synthesis gas into the national gas transmission grid reveals, that the latter is a competitive option to decrease Bulgaria's gas import reliability by 100 %. EU environmental strategies to achieve a reliable, efficient and clean energy production do not only focus on decreasing import dependency, greenhouse gas emissions by increasing the share of renewable energy in final energy consumption, or the application of CO_2 avoidance technologies. Another strategy taken into account is the decrease of energy intensity. To quantify the impact of varying energy intensity (intensity per unit of activity level) in the Bulgarian demand sector on the electricity production output and resulting CO_2 emissions, a scenario analysis is applied. Thereto, three cases considering low energy intensity (LEIG), medium energy intensity (MEIG) and high energy intensity (HEIG) for the baseline, the CCS-PP and the UCG-CCGT-CCS scenarios are examined. Simulation results for the baseline scenario demonstrate, that varying energy intensity from LEIG to HEIG by 1 % (0.4 % to 1.4 %) causes a CO_2 emission difference of about 3.8 Mt CO_2 (16 %) in 2020 and 5.2 Mt CO_2 (46 %) in 2050. The CO_2 emission difference between LEIG and HEIG is related to a higher primary energy consumption in case energy intensity increases. A high energy intensity per unit of activity level (due to e.g. the application of outdated technologies in households or the transport sector) results in decreasing energy input yields. In the baseline scenario, EU guidelines on CO_2 mitigation are neither achieved in the LEIG nor in the HEIG scenario. In the HEIG CCS-PP and UCG-CCGT-CCS scenarios the environmental targets are obtained, with the exception of not achieved EU environmental targets on CO_2 mitigation in the UCG-CCGT-CCS scenario for 2020 (the permitted value is exceeded by 3.2 %). Taking into account the LEIG case, environmental targets in the UCG-CCGT-CCS and CCS-PP scenarios are achieved.

5.2 UCG-CCGT-CCS as Competitive and Carbon Neutral Option for Energy Supply in Bulgaria

According to the objectives of this thesis to develop an instrument for site specific UCG-CCGT-CCS COE determination, quantify UCG-CCGT-CCS COE variation bandwidths due to model input data uncertainties and assess the economical and CO_2 mitigation potentials UCG-CCGT-CCS offer to the national Bulgarian energy system, the following conclusions can be drawn.

- To determine COE, the methodological approach of combining geological, engineering and economic analyses are chosen, because efficiency and success of a coupled UCG-CCGT-CCS system are governed by complex interactions of site-specific geological, chemical, technical and market-dependent boundary conditions.

- Being determined by 130 model variables, the techno-economic model is transposable to quantify UCG-CCGT-CCS economics in any coal deposit world-wide, taking into account site-specific boundary conditions and operational process design.

- Site-specific focused economic surveys via the techno-economic model have to be undertaken for each (previously explored) study area individually, whereby results cannot be transferred from one target area to another.

- In comparison to averaged European CCGT-CCS costs of electricity which according to ZEP (2011) amount to 105 €/MWh, UCG-CCGT-CCS COE of 71.67 €/MWh for the selected target area demonstrate, that the coupled UCG-CCGT-CCS process is a competitive option for low carbon electricity production.

- Multivariate sensitivity analysis results reveal costs of electricity bandwidths of up to 104 €/MWh. This result can be explained by the fact that for model input parameters aligned with high uncertainty due to lack of data, or those known to have a relevant impact on COE, a variability of up to ± 25 % is chosen to ensure uncertainties are adequately addressed. In the present study, model input parameters with high uncertainty belong to the surface facilities (air separation unit, synthesis gas processing plant). A reduction of the overall uncertainty range can be achieved by precise information on the technical and market-dependent target areas boundary conditions.

- Besides geological boundary conditions UCG-CCGT-CCS feasibility and competitiveness strictly depend on geographical and infrastructural boundary conditions. Thus, UCG-

CCGT-CCS competitiveness must not be assessed at a local scale only, but also at a national macro scale.

- A high share of fossil power in the overall Bulgarian energy mix and a technically outdated power generation system hamper the realization of the EU environmental targets on CO_2 mitigation. According to simulation results, EU environmental targets will not be achieved without a remarkable increase of energy efficiency and the application of transition technologies such as e.g. UCG-CCGT-CCS and CCS equipped power plants.

- The elaborated UCG-CCGT-CCS and CCS-PP implementation concept shows that, related to infrastructural and geographical aspects examined in this study, the implementation of both technologies into the Bulgarian energy system is practicable.

- UCG-CCGT-CCS and CCS-PP economic competitiveness, in comparison to other fossil fueled power generation technologies, significantly depends on boundary conditions such as CO_2 emission charges and CCS technological progress. According to the boundary conditions assumed in the current study, UCG-CCGT-CCS and CCS-PP COE can compete with conventional Bulgarian fossil energy production technologies COE, especially in line with future rapidly raising CO_2 emission charges (20 to 80 €/t CO_2).

5.3 Future Research Activities

Taking into account the results and conclusions elaborated for this thesis, the following issues should be addressed in future works.

- Further research activities focus on a dynamic coupling of the techno-economic model to a Geographic Information System (GIS) database with potential UCG-CCGT-CCS target areas. This system could be further utilized to quantify and compare site specific uncertainties related to lack of data or varying boundary conditions (e.g. site-benchmarks).

- Further techno-economic model developments should focus on the surface installation setup by applying thermodynamic process modeling considering heat and energy utilization as well as optimizing the volume flow related plant design. Optimization of the latter mainly refers to the ASU and synthesis gas processing sub-models. A possible realization approach is applying appropriate modeling software tools, e.g. the open source ChemSep simulator (Kooijman and Taylor, 2006, 2012) or the commercial ASPEN software (ASPEN, 2013).

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Curriculum Vitae

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