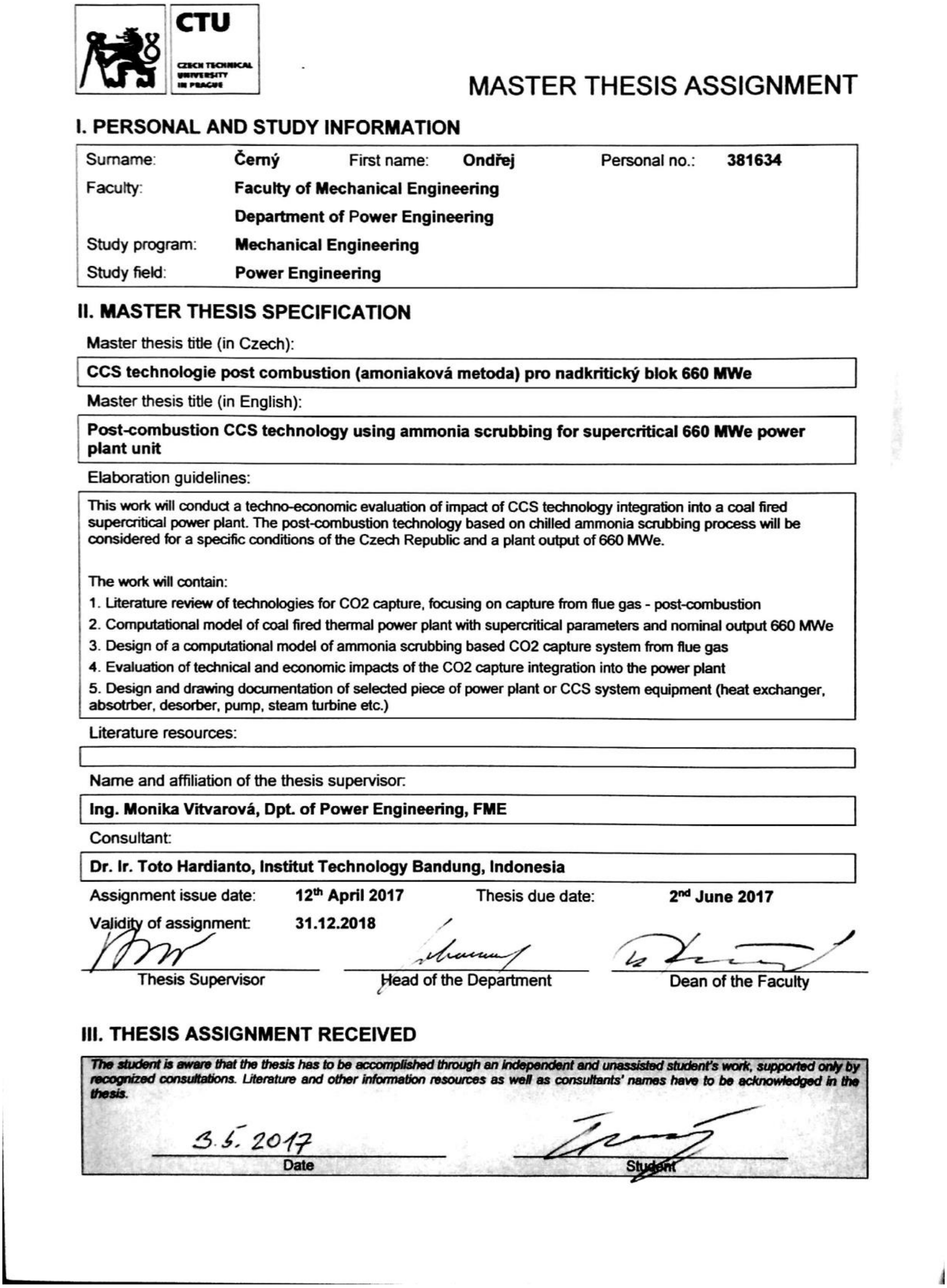
Czech Technical University in Prague

FACULTY OF MECHANICAL ENGINEERING

MASTER´S THESIS

2017

ONDŘEJ ČERNÝ



CTU
CZECH TECHNICAL UNIVERSITY IN PRAGUE

MASTER THESIS ASSIGNMENT

I. PERSONAL AND STUDY INFORMATION

Surname:	**Černý**	First name:	**Ondřej**	Personal no.:	**381634**
Faculty:	**Faculty of Mechanical Engineering**				
	Department of Power Engineering				
Study program:	**Mechanical Engineering**				
Study field:	**Power Engineering**				

II. MASTER THESIS SPECIFICATION

Master thesis title (in Czech):

CCS technologie post combustion (amoniaková metoda) pro nadkritický blok 660 MWe

Master thesis title (in English):

Post-combustion CCS technology using ammonia scrubbing for supercritical 660 MWe power plant unit

Elaboration guidelines:

This work will conduct a techno-economic evaluation of impact of CCS technology integration into a coal fired supercritical power plant. The post-combustion technology based on chilled ammonia scrubbing process will be considered for a specific conditions of the Czech Republic and a plant output of 660 MWe.

The work will contain:

1. Literature review of technologies for CO2 capture, focusing on capture from flue gas - post-combustion
2. Computational model of coal fired thermal power plant with supercritical parameters and nominal output 660 MWe
3. Design of a computational model of ammonia scrubbing based CO2 capture system from flue gas
4. Evaluation of technical and economic impacts of the CO2 capture integration into the power plant
5. Design and drawing documentation of selected piece of power plant or CCS system equipment (heat exchanger, absotrber, desorber, pump, steam turbine etc.)

Literature resources:

Name and affiliation of the thesis supervisor:

Ing. Monika Vitvarová, Dpt. of Power Engineering, FME

Consultant:

Dr. Ir. Toto Hardianto, Institut Technology Bandung, Indonesia

Assignment issue date:	**12th April 2017**	Thesis due date:	**2nd June 2017**
Validity of assignment:	**31.12.2018**		

Thesis Supervisor
Head of the Department
Dean of the Faculty

III. THESIS ASSIGNMENT RECEIVED

The student is aware that the thesis has to be accomplished through an independent and unassisted student's work, supported only by recognized consultations. Literature and other information resources as well as consultants' names have to be acknowledged in the thesis.

3.5.2017
Date

Student

Prohlášení

Prohlašuji, že jsem svou diplomovou práci vypracoval samostatně pod vedením Ing. Moniky Vitvarové, Ing Václava Novotného a použil jsem pouze podklady uvedené v seznamu na konci diplomové práce.

Nemám závažný důvod proti užití tohoto školního díla ve smyslu § 60 Zákona č.121/2000 Sb., o právu autorském, o právech souvisejících s právem autorským a o změně některých zákonů (autorský zákon).

V Praze dne 2.6.2017 ……………………..………………….

podpis

Poděkování

Úvodem bych chtěl poděkovat vedoucím mé diplomové práce, Ing. Monice Vitvarové a Ing. Václavu Novotnému za trpělivé vedení, poskytnutou literaturu a její podmětné rady při tvorbě této práce. Také bych chtěl také poděkovat svému konzultantovi Dr. Ir. Toto Hardiantovi a dále rodičům, přátelům a partnerce za jejich podporu a trpělivost, se kterou mi byli oporou po celou dobu studia a tvorby této práce.

Anotace diplomové práce

Autor: Ondřej Černý

Název DP: CCS TECHNOLOGIE POST COMBUSTION (AMONIAKOVÁ METODA) PRO NADKRITICKÝ BLOK 660 MWe

Akademický rok: 2016/2017

Škola: České Vysoké Učení Technické – Fakulta Strojní

Ústav: Ú 12115 – Ústav energetiky

Vedoucí: Ing. Monika Vitvarová

Konzultant: Ing. Václav Novotný

Klíčová slova: CCS, uhelné elektrárny, Post combustion, snižování emisí CO_2

Anotace: Tato práce se zabývá možnostmi využití Post combustion CCS technologie v ČR. Hlavní pozornost je věnována integraci této technologie pro uhelné nadkritické elektrárny. Jsou zde popsány základní typy CCS technologií a technicko-ekonomická analýza začlenění Post combustion CCS do uhelné elektrárny pracující v nadkritických parametrech páry. Dále je zhodnocen potenciál využití CCS technologie Post-combustion v ČR.

Abstract of diploma thesis

Author: Ondřej Černý

Title: POST-COMBUSTION CCS TECHNOLOGY USING AMMONIA SCRUBBING FOR SUPERCRITICAL 660 MWe POWER PLANT UNIT

Academic year: 2016/2017

University: Czech Technical University in Prague – Faculty of Mechanical Engineering

Department: Ú 12115 – Department of power engineering

Supervisor: Ing. Monika Vitvarová, Ing. Václav Novotný

Keywords: CCS technologies, Steam power plants, Post-combustion, Reduction of CO_2 emission

Summary: This thesis deal with the possibility of using Post-combustion CCS technology in the Czech Republic. The thesis is focused on the integration of this technology for the steam cycle power plant. The main types of CCS technologies are introduced. Technical and economic analysis of steam power plant with Post-combustion CCS technology is presented. Potential of using Post-combustion CCS technology in the Czech Republic is assessed.

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LIST OF ABBREVATIONS

Ca – Calcium

CCPP - Combined Cycle Power Plant

CCS - Carbon Capture and Storage (or Carbon Capture and Sequestration)

CO_2 - Carbon dioxide

ECBM - Enhanced Coal Bed Methane recovery

EOR - Enhanced Oil Recovery

ESA - Electrical Swing Adsorption

MEA - Mono Ethanol Amine

HRSG – Heat recovery steam generator

PSA - Pressure Swing Adsorption

TSA - Thermal Swing Adsorption

Contents

1. Introduction

Currently, there is a global effort for reduction of emitted carbon dioxide (CO_2). Carbon dioxide is identified as a very significant greenhouse gas. If human kind wants to keep the rate of economic growth without a disproportionately negative impact on the environment, we have to reduce the amount of all greenhouses gases. Especially it is necessary with growing amount of its emission due to growing economies in developing country. The human rise is looking for options how to control and reduce the amount of the carbon dioxide. One of the solutions for this problem is Carbon Capture and Storage (CCS). CCS technology using remaining fossil fuels and same technology of the power generation. Only CCS technology can reduce the emission of the carbon dioxide from the fossil fuels by the 90 % and more. Also, it is the only available option how to reduce the emission of carbon dioxide for some of the industrial operations as steel production, cement production and production of some others chemicals.

The primary problem of this technology is economically suitable. For mass usage is need to reduce cost and power consumption. With using nowadays technologies we can achieve same goal but with higher cost and efficiency drop.

One of the promising CCS technologies is using post-combustion. This technology is different from the rest of the CCS technologies because this one is suitable for existing power plant. Instead of it, fuel is combusted in standard air. Therefore, the flue gas is containing a lot of additional gases and compounds. The technology will be introduced in the following chapter.

The purpose of this thesis is to evaluate the possibility of using post-combustion technology for existing power plant in the condition of Czech Republic. The power plant which will be designed with the CCS unit will be then compared with power plant without this technology. The power plant will be designed according to the scheme of the Ledvice power plant which is situated in the Czech Republic.

1.1. Definition of CCS

Carbon capture and storage cover a broad range of principles for low carbon technology which captures CO_2 from the combustion of fossil fuels such as coal or gas for power generation and from the manufacturing of steel, cement and other industrial facilities, rather than being emitted to the atmosphere. CCS technology involves three major steps (Figure 1):

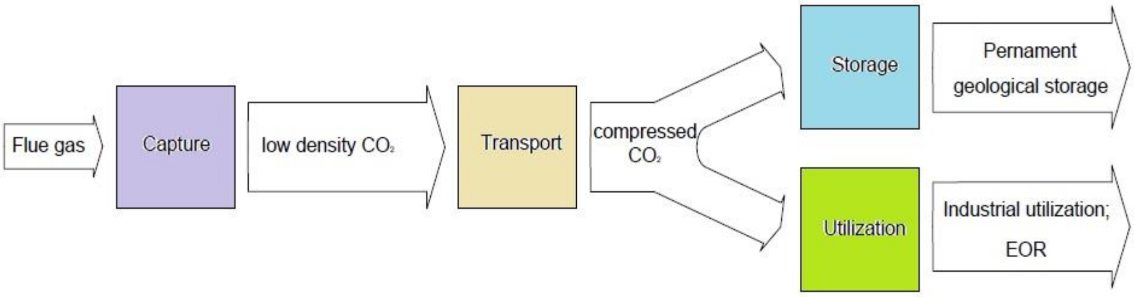

Figure 1- Major steps of CCS [3]

1.1.1. Capture

The first task of CCS technologies is separation of CO_2. According to technology of CCS (Post-combustion, Oxyfuel, Pre-combustion), the amount of CO_2 in flue gases is substantially different. These differences arise from combustion of fuel and air with different amount of oxygen. The second reason of differences can be preparation of fuel before burning. The CCS technologies can capture around 90% of the CO_2 from the combustion of coal, gas and even biomass. [1] [2] [3]

1.1.2. Transport

In this step is included the transport of CO_2 separated from the place of production (power plant) to the place of storage and compression of the product of separation to the required pressure. Especially the compression process is very energy consuming. Although pipelines are the most likely option for large-scale carbon dioxide transportation, shipping and road/railway transport are also considered possibilities. Fortunately, suitable technologies for transportation are well known and used. Only minor adjustments need to be performed for the most technologies to transport natural gas, petroleum gas, etc. to CO_2 transport can be used for as well.

The price for transportation is small when compared transport and capture. Only for decentralised power sources or if there will need to build a long pipeline for transportation, it can be the determinative factor in consideration of this technology. [1] [2] [3]

1.1.2.1. Pipeline transport

The pipeline for CO_2 transportation can be almost identical as a pipeline for natural gas only with some differences. All around world is more than 6 500 km of CO_2 pipeline and most of them are in the USA and it is used for EOR [38]. The different between natural gas and CO_2 is the limit for the amount of nitrogen or H_2S in a pipeline, for example. Nitrogen could overstep the limit in the pipeline. Amount of H_2S should be smaller due to a danger of leakage in the populated area.

The CO_2 is transported as a compressed gas. The low-pressure pipeline should operate under the 4.8 MPa and high-pressure pipeline should operate over 9.6 MPa [39]. It cannot be transported as gas in atmospheric pressure due to the huge volume of gas which would be needed to transport. The liquefied CO_2 is not able to transport by pipeline due to technological problems with cooling of the gas along the pipeline. The total cost depends on terrain and position of a pipeline. Offshore pipelines are mostly more expensive than onshore. The cost can be significantly increasing with ground effect (mountains, river, natural parks and heavily urbanised places).

The cost of the pipeline can be divided into four parts:

- Material cost (installation, pipes…)
- Equipment cost (pipes protection, telecommunication equipment...)
- Operation and maintenance cost
- Other fees (insurance, regulatory fees, design, project management...)

1.1.2.2. Ship transport

The ship transport isn't continuous process. It means, then in the case of ship transport there will be a need for loading facilities, temporary storage tanks and another facility at the start and the end of the ship transport. The transportation of CO_2 is almost same as liquefied petroleum gas (LPG). Exist two possibilities for a ship, how to transport carbon dioxide.

- Compressed CO_2 (solid CO_2 which is called dry ice)
- Semi-refrigerated (cooled down and compressed)

Nowadays are in duty 4 ships for CO_2 transportation and all of them have second design [32]. The safety of naval transportation is high. The most of cases sinking or damage of the ship was caused by the old, poorly maintained ships or unqualified crew. The accidents due to technical failure are relatively negligible.

1.1.3. Storage/Utilization

The last step of the process is successful storage of separated and compressed CO_2 in permanent storage. As a commonly considered method of storage is considered the injection of CO_2 in carefully controlled and selected geological formation – salt aquifers. [2]

In the innovative field of Carbon Capture and Utilisation, CO_2 waste emissions from large emitters is captured and used to produce new products and provide economic opportunities. One of the methods as use captured CO_2 is Enhanced Oil Recovery (EOR). [3]

1.1.3.1. Underground geological storage

Underground geological storage is naturally way, how to accumulate CO_2. Currently, there are two options for geological storage. One of them is EOR and second one is Enhanced coal bed methane recovery (ECBM). These two technologies have a similar background. In ECBM is the CO_2 is injected into oil or coal bed and it is absorbed in the rest coal by the carbon. This reaction release methane. The ECBM have a problem due to economic suitable. The EOR work very similarly. CO_2 is injected to oil deposits and the effect is the higher production of oil and natural gas. The cost of all ways of geological storage depends on location, many injections, depth.

The simple geological storage is possible as well, the price was estimated as an almost half of price for EOR per one tonne, but there is no additional product, which makes EOR suitable for more deployment. Over the world is huge capacity for CO_2 storage but regard to economic viability, technical feasibility, safety, environmental and social sustainability.

Another question is the impact of potential leakage of CO_2. It could make degradation of groundwater quality, damage of minerals and hydrocarbons, deadly effects on plants and subsoil animals. Also, there is possible impact on seismic activity and geological changes. There are also health and safety concerns.

1.1.3.2. Ocean storage

Another option is the ocean storage. This method does not require geological deposits where CO_2 would be trapped, but it is using prosperities of water and slow changes in oceans. There are two basic options how to store the CO_2 in the oceans:

- Disperse carbon dioxide into the ocean where it will be dissolved
- Pumped carbon dioxide into the great depth of oceans where it will create lake of CO_2

Oceans covers over 70% of the earth's surface and their average depth is 3,800 m. A potential CO_2 storage possibilities are to inject captured CO_2 directly into the deep ocean (at depths greater than 1,000 m), where most of it would be isolated from the atmosphere for hundred years because in these depths CO2 has higher density than sea water and it will create lake of carbon. The dissolved and dispersed CO_2 would subsequently become part of the global carbon cycle. That reasons and fact, that the ocean can store much more CO_2 than people can produce, it seems a suitable place for CO_2.

The problem is than the injection of several $GtCO_2$ would a significant cause change in the ocean chemistry in the area of injection but injection of hundreds of $GtCO_2$ could change the chemistry of the whole Ocean. Ocean storage has not yet been deployed or demonstrated at a pilot scale, and is still in the research phase. However, there have been small-scale field experiments and 25 years of theoretical, laboratory and modelling studies of intentional ocean storage of CO_2. The research took maximally several months and investigated only organism living near the ocean surface. Near the injection point and lakes of CO2 is expected increasing mortality. Long term effects and effects to deep-sea organism are unexplored. There are also many options how to reduce impact to the ocean. For example, by dissolving of carbonate minerals (limestone) would help to keep the pH of the water. The cost of transportation is very significant. In the opposite of it is the cost of disposal and monitoring of the chemistry changes. It should be relatively small compare to cost of transport. Using of ocean as storage for CO_2 is in early stage of research and further technical progress will be required. [39]

This thesis does not include the way of transportation and storage of CO_2. To determine it further investigation would be needed to evaluate possibilities as local storage, selling of CO_2, building of pipeline as well as local legislation and many other aspects that would include an excess range of this thesis.

1.2. Technology for capturing CO_2

For capturing of CO_2 can be used three basic methods:

1.2.1. Post-combustion

The Post-combustion carbon capture is the most common and widely considered process of capturing CO_2. In this method, a solvent is used to separate CO_2 from other gases in the flue stack after combustion of the fossil fuel, from which is CO2 released in regeneration. The most common solvent is chilled ammonia; however, other selective amines and generally range of chemical sorbents can be also used. The basic principle (shown below in Figure 2.) has been known several decades and Post-combustion has great potential for use in existing process with smallest modifications of the three processes. [3] [5] [6]

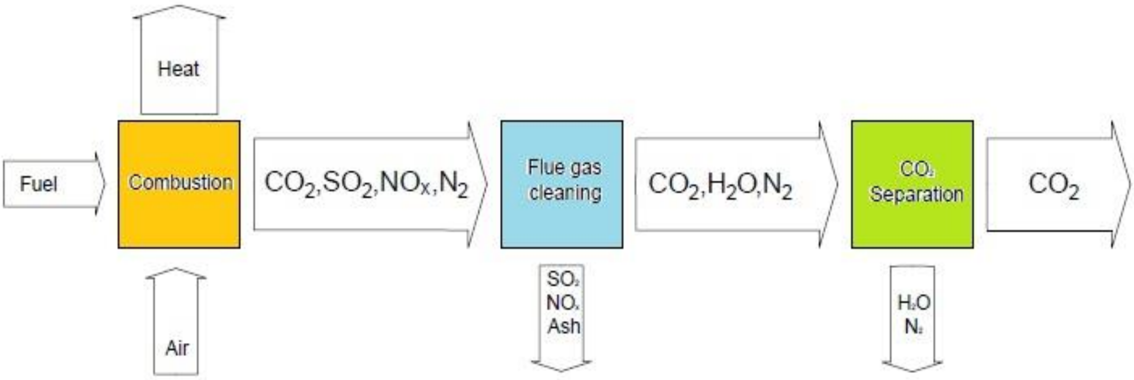

Figure 2 - Scheme of Post-combustion

1.2.2. Oxyfuel

This model of combustion process simplifies CO_2 separation. Oxyfuel combustion involves combustion of a fossil fuel in the presence of relatively pure oxygen (O_2) with content of O_2 95-99% (with small amount of N_2). The Oxyfuel combustion is almost at stoichiometric conditions. Resulting flue gas consist mainly of CO_2 (90-95%), water vapor, noble gas and SO_x and NO_x, depending on the fuel composition. The simplified process scheme is shown below (Figure 3). [6]

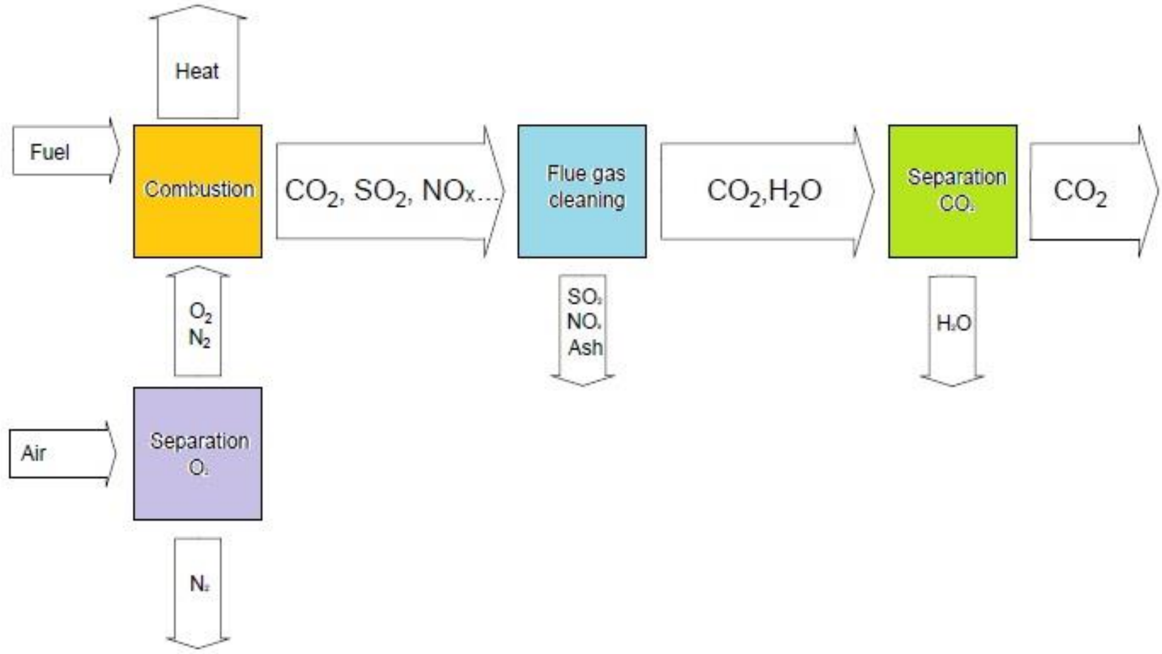

Figure 3 - The scheme of Oxyfuel combustion

1.2.3. Pre-combustion

The capture by a pre-combustion technology is separation of carbon from the fossil fuel before combustion by transforming duel into carbon-free state. The technology of Pre-combustion comprises reforming of fossil fuel (or biomass) into a syngas consisting mostly of CO and H_2. This mixture is through a shift conversion transforming CO and (added) H2O into a mixture composed of CO2 and H_2, where CO_2 can be then separated. The output from this reaction is fuel consisting mostly of hydrogen and the hydrogen can be burned cleanly to create electricity (in gas turbine combined cycle), be used for other industrial applications or, in future, possibly used in producing of electricity in fuel cell. The process of Pre-combustion is shown in simplified Figure 4.

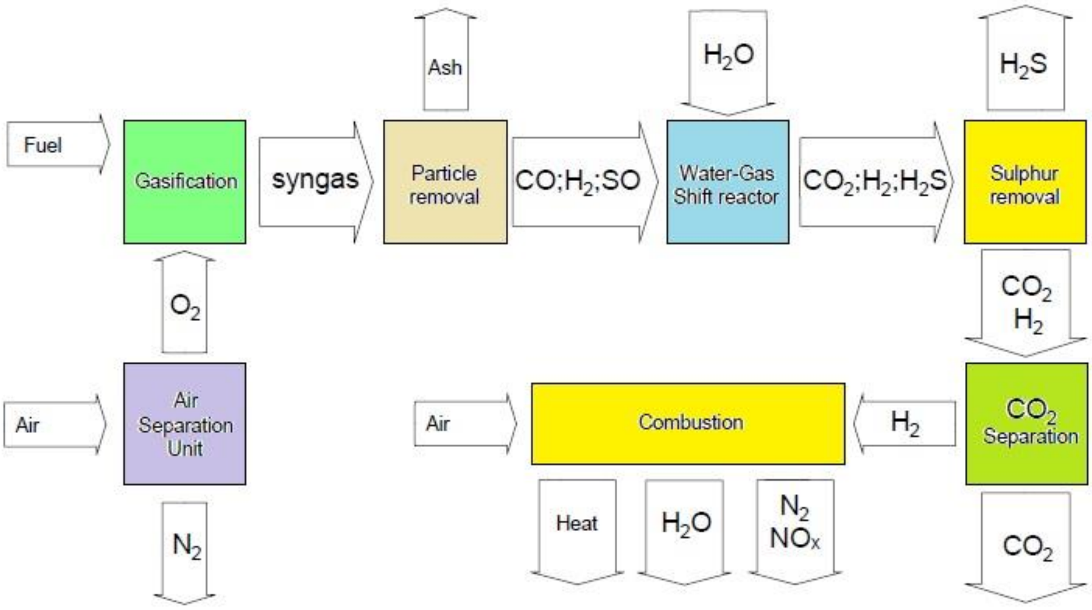

Figure 4 - Scheme of Pre-combustion

This thesis is focused on The Post-combustion method, more information on this topic outlined below.

2. Post- combustion

As is showed above, this thesis analyses the technology of post-combustion. For recapitulation, this technology is the simplest for implementing to existing plant of the above possibilities because it works with flue gases which have been combusted in the conventional combustion. This method is suitable for already existing plants. Burning of fossil fuels produces flue gases, which include CO_2, water vapor, sulfur oxides and nitrogen oxides. For capturing of CO_2 from flue gas we can use specific methods of capture. In these methods are mostly used a solvent that absorbs carbon dioxide. Post-combustion carbon capture design is typically considered to avoid 80-90% of power plant's carbon emissions from entering the atmosphere. [6] The post-combustion process is typically the most energy consuming; one of reasons is it must process a large volume of flue gas.

2.1. Methods of CO_2 capture

2.1.1. Chemical absorption

Solvent absorption is a cyclic chemical reaction, however CO2 reacts with solvent (liquid) and the binding is done by creating different compound. The regeneration of that compound reverses the reaction by operating at different temperature. The flue gas stream, with most of the CO_2 removed, is then emitted to the atmosphere. The resulting CO_2 free liquid is reused for absorption. This technology is quite widely used in many applications, but it needs a large amount of energy to regenerate the solvent. [7]

More information about substances use in chemical absorption is showed below in chapter 3.

2.1.2. Physical absorption

CO_2 capture using physical sorbents and inorganic porous materials consumes lesser energy when compared with CCS with chemical sorbents. Some well-known materials have the disadvantage of poor CO_2/N_2 selectivity, so this essentially means that it is not suitable for capture in low concentration CO_2, as is post-combustion. If the challenges of selectivity in physical sorbents and membranes are successfully overcome, their use for CO_2 capture could be a good potential for energy saving compared to the dominant amine-based absorption systems. [12]

2.1.3. Adsorption

Adsorption has the same function and principle as absorption. Basically, Adsorption provided by gas–solid intermolecular forces, instead of absorption which is based on gas-liquid reaction. Typically used is a mineral zeolite. The solid is purified in equipment using differences in either pressure or temperature to remove the carbon dioxide and compress it for storage. [7]

2.1.4. Methods of regeneration

For Absorption and Adsorption are generally methods of regeneration with swing of temperature or pressure. The pressure swing adsorption (PSA), the mixture gas flows through the adsorbent at an increased pressure until the desired gas concentration near equilibrium. The adsorbent is regenerated by reducing the pressure. This method is very useful for physical sorption.

In temperature swing adsorption (TSA), the adsorbent is regenerated by raising its temperature. PSA and TSA are commercially used methods of gas separation. Adsorption is not still considered attractive for large-scale separation of CO_2 from flue gases, because the capacity and CO_2 selectivity of available adsorbents is low. However, it can be successfully combined with other technologies to capture. [8]

2.1.5. Membranes

Gas separation membranes allow one component in a gas stream to pass through faster than the others. The membrane is basically filter, which captures the particles of the different size, charge or phase. There are many different types of gas separation membranes, including porous inorganic membranes, palladium membranes, polymeric membranes and zeolites. Membranes cannot usually achieve high degrees of separation, so multiple stages and/or recycle of one of the streams is necessary. This leads to increased complexity, energy consumption and costs. [7] [8]

2.1.6. Cryogenics

This technology is not fully suitable for the post-combustion technology, but is applicable. Flue gases are cooling and condensing. Different fractions are removed individually by difference in condensation temperatures. CO2 is removed after the previous condensable fractions (H_2O). A major disadvantage of cryogenic separation is the amount of energy required to provide the refrigeration necessary for the process, particularly for dilute gas streams. Cryogenic separation is used for streams with high concentrations of CO_2 (typically more than 90%) [7] In case of the use of this technology in the post-combustion capture it is necessary first concentrate $CO_{2.}$ The big advantage of cryogenic separation is that it enables direct production of liquid CO_2. This is needed for certain transport options and limits large compression work by allowing compressor to be supplemented by a pump.

2.1.7. Calcium looping

Although this method can be classified in common absorption/adsorption, the technology of Calcium (Ca) looping has special significance, and is sorted separately. It is one of the most promising processes for CO_2 capture in near future. The sorbent reacts with gaseous CO_2 at high temperatures (600-750 °C) by forming a solid calcium carbonate ($CaCO_3$). $CaCO_3$ formed in this reactor is then regenerated into CaO by oxy-fuel combustion in a calciner, which operates at high CO_2 partial pressures to facilitate its later purification, compression and storage. Since the carbonation reaction is highly exothermic, heat must be provided to decompose $CaCO_3$ back into CaO. Separated CO_2 has high temperature; therefore, this concept counts with two parallel HRSGs – one for cleaned up flue gas and another for CO_2 stream. The simplified scheme is shown below on Figure 5. [9]

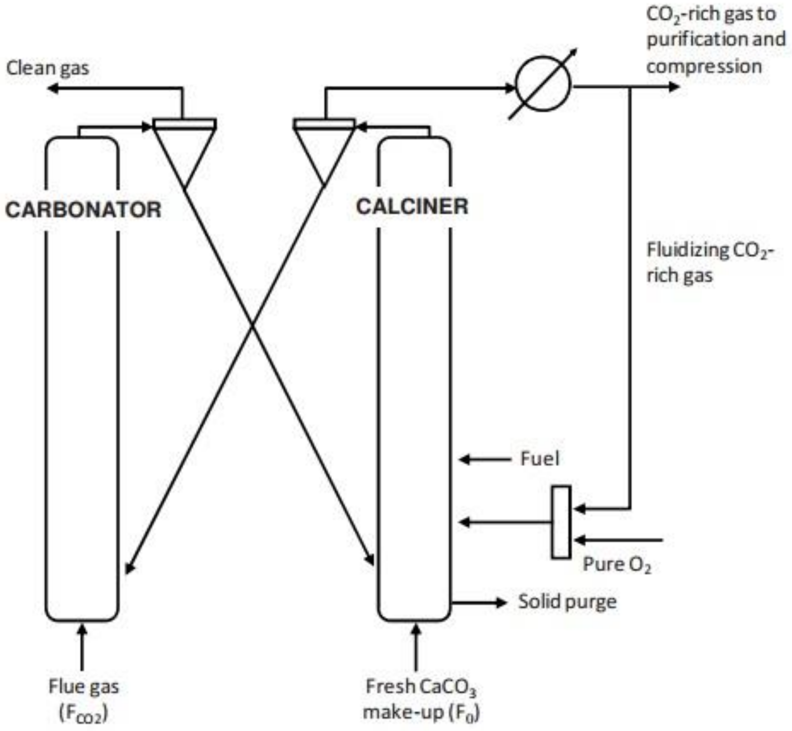

Figure 5 - Scheme of the Ca-looping process focused on removing CO_2 [9]

3. Chemical solvents

Currently most commonly used technology for capturing of low concentrated CO_2 is absorption with chemical solvents. This chemical absorption process is originally from the gas processing industry, which have been used in processes based on amines commercially for removing acid gas impurities from streams of process gases. Processes for CO_2 capture require large amounts of solvent, which leads to significant changes in conditions, leading to high investment costs and energy consumption. Furthermore, most of solvents are problem with stability and degradation at the time. Some of them (ammonia) require hazardous material handling processes. [10]

3.1. Undesirable aspects solvents

To achieve an economical and efficient process of CO_2 absorption, it is essential to have a solvent that is stable under a wide range of conditions. When the selected solvent is unstable, it may cause the formation of undesirable properties.

3.1.1. Degradation

The ideal solvent is stable. It means than the solvent can be used for capturing of CO_2 from flue gas and reclaiming (unlimitedly. Unfortunately, none of the known solvents is not completely stable.

The main problem in a chemical absorption is the degradation of the solvent during irreversible side reactions with CO_2 and other flue gas components, which makes the process complicated. CO_2 reacts reversibly in an absorber with chemical solvents which are regenerated by heating. A main problem associated with chemical absorption using amines is degradation through irreversible side reactions mainly with CO_2 and O_2 but also with NOx and SOx. These reactions can lead to different problems with the process: solvent loss, formation of volatile compounds potentially dangerous for environment, foaming, fouling and corrosion. [35]

3.1.2. Corrosivity

The corrosivity of environments in CCS plant will be affected by the availability of reactants including CO_2, other acids, oxygen and Sulphur. Free water is a necessary requirement for low temperature corrosion. Corrosion will not occur in gas streams above the dew-point or where no liquid water phase (or some other electrolyte) is present. The solubility and behaviour of water and CO_2 mixtures is therefore of critical importance for corrosion in CCS plant.

Degrading solvents, forming a variety of products including organic acids and heat-stable salts which increases the corrosivity of the environment as well as increasing the consumption of amine and reducing the efficiency of operation. As well as being corrosive to carbon steel, these acids can cause damage to stainless steels at the temperatures in the reboiler. [36]

3.1.3. Hazardous characteristics

In the world exist many options how describe hazardous proprieties. Basically, hazardous material is any item or agent. which has the potential to cause harm to humans, animals, or the environment, either by itself or through interaction with other factors. Some materials can be safely produced with minimal environmental and human health concerns during its use or disposal. Other materials are hazardous to manufacture or use and, when disposed, can contaminate and persist in the environment. Characterization and assessment methods are needed to correctly identify substances of concern and to evaluate in a systematic way the degree of hazard they pose to ecological systems and human health. [37]

3.2. Amine Solvents

The most preferred chemical solvent technology for carbon capture is amine-based chemical absorbent. CO_2 in the gas phase can be dissolved into water with amine compounds. Upon reaction of CO_2 and amines, the resulting solution contains protonated amine (AH+), bicarbonate (HCO_3-), and carbamate (ACO_2-). When the solution has reached the intended CO_2 loading, it is removed from contact with the gas stream and heated to reverse the chemical reaction and release high-purity CO_2. CO_2-poor amine solvent is then recycled to contact further gas. At first flue gas, must be cooled and to free of reactive impurities, such as Sulphur, nitrogen oxides and particulates. Otherwise, these impurities may be preferably reacted with amines, which reduces the capacity for CO_2 or irreversibly poison solvent. The resultant pure CO_2 stream is recovered at a pressure near atmospheric pressure. Alkanolamines, combinations of alcohols and ammonia, are most frequently used category of amine chemical solvents for CO_2 capture. Reaction rates, absorption characteristics and different the sensitivity of the amines types also differ due to solvent stability and corrosion. Alkanolamines can be divided into three groups:

- Primary amines, including mono-ethanol amine (MEA) and diglycolamine (DGA)
- Secondary amines, including di-ethanol amine (DEA) and diisopropyl amine (DIPA)
- Tertiary amines, including tri-ethanol amine (TEA) and methyldiethanol amine (MDEA)

Mono-ethanol amine (MEA) is a widely-used type of amine for CO_2 capture. CO_2 recovery rates of 98% and product purity in almost 99% can be achieved. The problem is rate of degradation in the oxidizing environment of a flue gas (three types of degradation for the amine solvent: thermal, carbamate oligomerization, and oxidative [34]) and the amount of energy required for regeneration. [8]

3.3. Aqueous ammonia

Another possibilities are use of Aqueous ammonia. The Ammonia-based wet separation has many similar properties to amine systems (scrubbing). Big advantage of this method is a significantly lower heat, resulting in energy savings. Another advantage over amine-based system, are potential for CO_2 capacity, tolerance to oxygen in the flue gas, lower cost and regeneration at high pressure.

3.4. Hybrid and novel solvents

Conventional technology for the capture of CO_2 has been primarily based on the use of chemical amine solvents. However, these solvents require significant amounts energy, high-grade process heat for solvent regeneration. This energy requirement creates an inefficient process with high operating costs. This problem has been identified as one of the major reasons currently limiting the wider deployment of post-combustion carbon capture technology. Additionally, conventional amine solvents suffer from significant operational and environmental issues including degradation, toxic aerosol emissions, sensitivity to flue gas contaminants, and corrosivity. The combination of different solvents or new explore solvents can have developed better final properties. These solvents are on the beginning of the research. Some examples are showed below.

3.4.1. Enzyme carbonic anhydrase

One of the most promising catalyst for carbon management is the enzyme carbonic anhydrase (CA). Developed by nature, CA exist in all living organisms and efficiently manages carbon dioxide during respiration. In an industrial CO_2 system, CA can be utilized as a catalyst to dramatically accelerate simple and benign salt solutions, and significantly reduced energy consumption. [13]

3.4.2. The APBS solvent

A new class of solvents APBS, patented by Carbon Clean Solutions has been specifically developed for carbon capture from power and industrial plants. The breakthrough technology could significantly reduce the operating costs and environmental impacts. Carbon Clean Solutions operates research facilities in the United Kingdom and in India. This solvent has very promising result in research, but composition is still secret. [15]

3.4.3. ION solvent

The overall goal of the project is to develop a new ionic liquid absorbent and an accompanying process for post-combustion capture of CO_2 from coal-fired power plants. ION Engineering, LLC will conduct bench-scale testing of an amine-based solvent that employs an ionic liquid instead of water as the physical solvent, greatly reducing the regeneration energy while lowering process water usage. In addition, energy requirements (the need for stripping steam is eliminated, greatly reducing the energy penalty, an ionic liquid-amine solvent mixture offers higher CO2 working capacity, reduced corrosion, reduced solvent loss, smaller units with reduced capital costs, the ability to use lower quality steam in regeneration, and other benefits when compared to conventional aqueous amine solvents. [14]

3.5. Dry Chemical Adsorbents

The many of solids which may be used to react with CO_2 to form the stable compound at one set of operating conditions, and then at another set of conditions, to the absorbed CO_2 is liberated and sorbent regenerated and reformed into the original compound. An exothermic reaction of sodium carbonate with CO_2 and water running at 60 to 70ºC [10] forms primarily sodium bicarbonate. The products must be heated to 120 to 200ºC [10] to reverse the reaction. Lithium zirconate is also being investigated for its high capacity of separation of CO_2 at high temperatures. [10]

4. Selected solvent

For the purposes of this study, it was necessary to obtain information about existing solvents. To this were used many information sources examining individual substances (see attachment 1). Based on the data thus obtained was determined a one specific solvent to be used to closer research.

4.1. Ammonia

From useful solvents was chosen ammonia. Ammonia occurs naturally and is produced by human activity and is relatively cheap and widely available. Ammonia is a compound of nitrogen and hydrogen with the formula NH_3. It is a colourless gas with a characteristic pungent smell. Ammonia is a compound of nitrogen and hydrogen with the formula NH_3. Ammonia is miscible with water. In an aqueous solution, it can be expelled by boiling (boiling point is −33.35 °C) [16]. Ammonia is highly soluble in water and has toxic and corrosive actions caused by its alkalinity. The maximum concentration of ammonia in water (a saturated solution) has a density of 0.880 g/cm^3 [17]. In ammine-based post combustion capture is mostly used the methods of temperature swing absorption for subsequent regeneration. Based on data from Table 1, the concentration of NH_3 is up to 15 wt% at lean solvent flow [25].

Solvent	CO_2 in flue gas	concentration NH_3	Absorption conditions		Desorption conditions		
			Temperature	Pressure	Temperature	Pressure	
	%	wt%	[°C]	[kPa]	[°C]	[kPa]	
NH_3	5		10	101	100	101	[23]
NH_3	5 - 15	9	20	120			[24]
NH_3		14,4	10	105			[25]
NH_3		2 - 6	0 - 10	101	100-120	500	[26]

Table 1 - Basic information about ammonia

The big advantage of ammonia-based methods is stability in the presence of Sulphur in flue gas. Especially, in case that the czech coal is fired, which is known for higher Sulphur content (1 - 15 % sulphur content) [33]. The high sulphur content makes big advantage for amine-based technology. The additional flue gas cleaning, before separation unit, is necessary for use in real operation.

Solvent	Energy requirement $[GJ/t_{CO2}]$	chemical stability (requirements of flue trace compounds) e.g. Sulfur compounds, NOx, water,… (After 1000 operation hours)	
NH_3	2.35	Does not degrade	[28]
NH_3	2.4	no degradation	[29]
NH_3	2.29		[30]
NH_3		does not degrade in the presence of O2 and other species in the flue gas	[31]
NH_3	1	does not degrade in a flue gas environment	[45]
NH_3	1.5		[46]

Table 2 - Expansion information about solvents

In second table (Table 2) is showed value of heat requirement for regeneration of solvent. All used studies found that the value in range 1 – 2.4 $GJ/t_{CO2.}$ This value is very variable and it is depending on many factors as ammonia concentration, design of capture unit, composition of flue gas etc. The above-mentioned study is very different in consumptions which are included to this value. After consultation with supervisor and consultant of this thesis was for later equation choose value 1.1 $GJ/t_{CO2.}$

Summary of the positive characteristics of ammonia-based separation are low-cost, less corrosive than other possible solvents and does not degrade in the presence of O_2, S and other species in the flue gas. The negative properties are toxicity. According to LD_{50} standard, the level of toxicity for human is inhalation around 9000ppm/ hour [28].

5. Reference power plant

The schematics of the reference power plant come out from power plant Ledvice, which is situated in the north-west part of the Czech Republic. Power plant Ledvice is coal-fired combination of subcritical and supercritical units. The critical units were constructed in the period of 1966 – 1969, with the total power output of 640 MW. This part of the plant underwent many modifications over the years, and some units are out of service. [18]

For purpose of this thesis is most important the supercritical part. The new 660 MWe unit was designed environmentally-friendly: Apart from electricity production, PP Ledvice supplies heat power for customers in nearby vicinity, and it provides heat power to the towns of Teplice and Bilina, through United Energy utility company. The electricity and heat power production combined in a single cycle, i.e. co-generation, reduces coal consumption per a power unit produced, thus partially eliminating environmental effects. Also the gross unit efficiency will reach approximately 47 %, which means a considerable reduction of CO_2 and other emissions, in accordance with recommendations of the European Union Best Available Technology standard, as the unit with the largest economically reachable energy effectiveness and lowest possible negative impacts to the environment. It was, therefore, necessary to reach the maximal possible operation parameters and minimize the emissions. The new unit is designed as a single unit design with one boiler featuring supercritical steam parameters and a four turbines casing steam condensation turbine. The location in the existing Ledvice power plant was proposed for construction of this unique (in Czech Republic and region of Central Europe) plant on the basis of a geological survey. The new unit will use coal from the adjacent open-pit brown coal / lignite mine in Bílina.

Figure 6 – Power plant Ledvice [20]

The heat generation is in a tower-type lignite boiler with supercritical parameters of superheated steam (1 698 t/h, 272 bar, 600 °C) with boiler efficiency of 91.3 %. Due to high steam operational parameters, high heat-resistant structural material grades, such as P92, T24, Super 304H and VM12, had to be implemented. At 135 meters, it is the highest building in the Czech Republic. [31]

The project is currently in the phase of hot commissioning and plant optimization. After problem with materials and weldability is a commercial start planned in the second half of 2017.

5.1. Used coal in reference power plant

The used coal for evaluation in this thesis is based on real brown coal/lignite mine from open-pit in Bílina, Czech Republic. The open-pit is in the immediate vicinity power plant Ledvice. Location within the Czech Republic is marked by the red cross in Figure 7. Here is exploited low-sulphur energy coal. The yearly mining is 8-9 million tonnes of coal. All coal extracted, depending on its quality, is sorted by sorting, crushing and separating in the Ledvice power plant for a wide range of customers in industry, energy, heating and municipal consumption. Most of the extracted coal is used as a fuel by Ledvice power plant. [43]

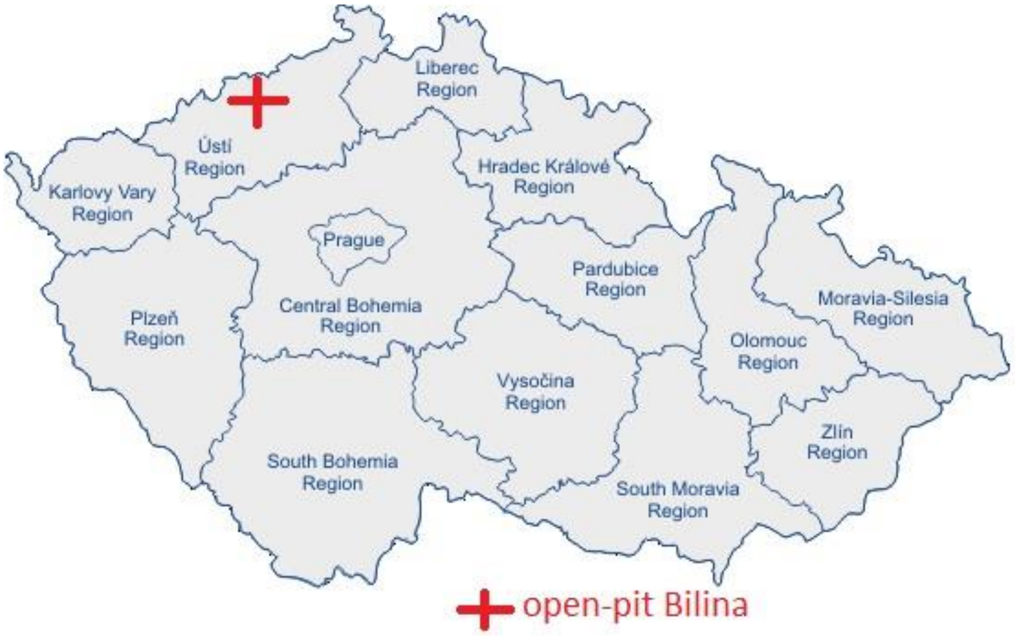

Figure 7- Location of open-pit Bílina [map source: http://www.eu2009.cz/en/czech-republic/regions/regions-of-the-czech-republic-329/]

The exact parameters and properties of brown coal/ lignite used as a fuel are showed below, in Table 3. The basic parameters of fuel are the Lower heating value (Qi^r), water content (Wt^r), Ash (A^d) and Sulphur in the raw state (S^r). The composition of combustible is stated as dry and ash free (daf).

parameters	Low value	Middle value	High value	unit
Qi^r	10.5	11.5	13.5	MJ/kg
Wt^r	22.5	25.4	28.5	% hm.
A^d	35.38	39.7	41.32	% hm.
S^r	0.76	0.82	1.04	% hm.
composition of combustible substances				
C^{daf}		66.67		% hm.
H^{daf}		5.6		% hm.
N^{daf}		1.03		% hm.
O^{daf}		24.87		% hm.
S^{daf}		1.823		% hm.

Table 3 - Fuel properties [50]

5.2. Steam cycle without CCS unit: Phase one

On the beginning of power plant design in the computer software was only simple scheme of reference power plant (Attachment 2) [51]. Based on the scheme of Ledvice power plant is designed to model of the steam cycle without CCS unit used as the reference unit for comparison of impact CCS unit to existing cycle in this thesis. From the basic scheme and other available was used many parameters (e.g. parameters of steam, the efficiency of boiler, parameters of cooling water etc.), but for completion function computer model must be calculated and determined (e.g. temperature of feed water heaters, etc.). The background of reference computer model power plant is same as the real unit although slight deviations are permitted in the parameters in various parts of the steam cycle. The simplified scheme of the cycle modelled in the computer program is in Figure 7. The detailed scheme modelled in program Cycle Tempo is in attachment 3.

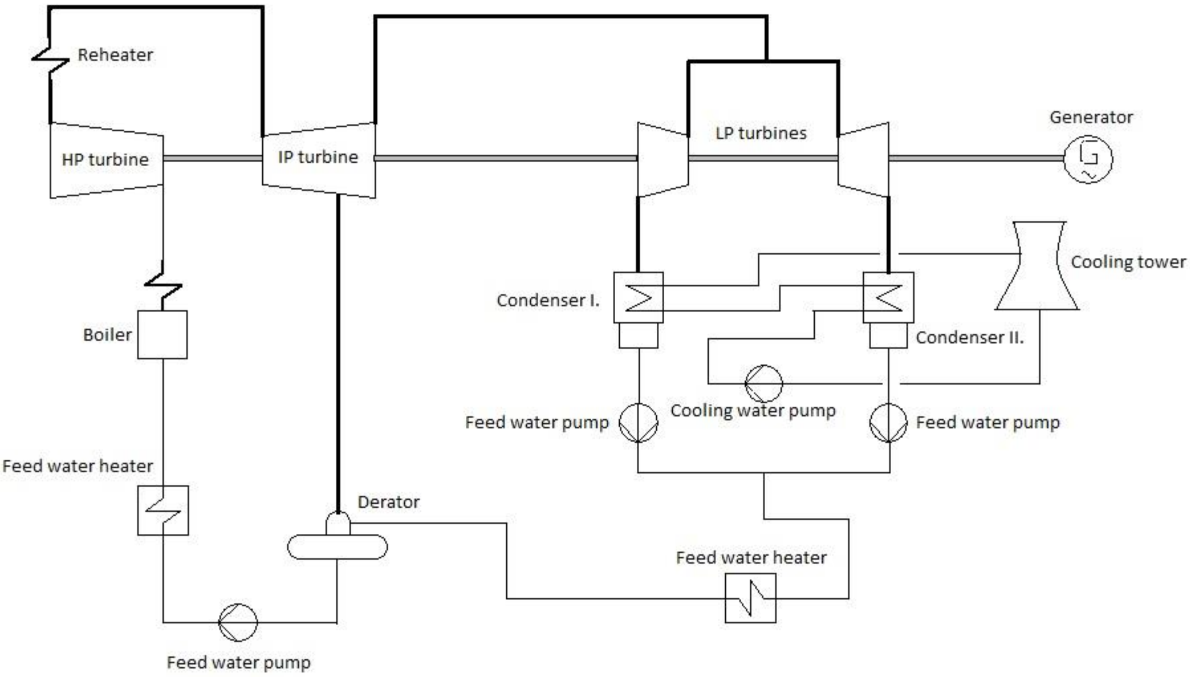

Figure 8 -The simplified scheme of reference steam cycle

This scheme is simplified. The high-pressure feed water heaters and low pressure feed water heaters are simplified and combined to one high pressure heater and one low pressure heater. Also in this simplified scheme aren't showed steam output from turbines to heaters.

The complete scheme of reference steam cycle is in attachment 3 and the list of all components in schema and their parameters are in attachment 4. The table showed above is only simplified version of attachment 2. The list of shortcuts from Table 3:

- HP = High pressure
- IP = Intermediate pressure
- LP = Low pressure

On the scheme of reference unit is a super critical steam cycle. The unit is using three pressure levels of steam (parameters in Table 4) one for high-pressure, one intermediate-pressure and two low-pressure parts of steam turbine. The interesting are condensers in series. It means different pressure of condensation, but the mass flow of condensing steam is similar for both condensers. Cooling water flows in one cooling system with one cooling tower.

Feed water from the condensers is going to low-pressure regeneration and to high pressure-regeneration (all parameters are in attachment 3 or Table 4). After the low-pressure regeneration, the water is pumped into deaerator. This deaerator is used for degassing of the water in feed water tank.

P_e [MWe]	660
η_{NET} [%]	44.109
$\dot{m}_{Fuel}$ [kg/s]	128
$\dot{m}_{Working\ fluid}$ [kg/s]	471.676

High pressure steam	
t [°C]	597
p [Bar]	265.1
$\dot{m}$ [kg/s]	471.676

Steam condensation	
p [Bar]	0.048; 0.035

Intermediate pressure steam	
t [°C]	608.55
p [Bar]	47.07
$\dot{m}$ [kg/s]	402.196

Low pressure steam	
t [°C]	329.48
p [Bar]	6.774
$\dot{m}$ [kg/s]	346.869

Table 4 - Parameters of the reference power plant

The computer model of reference power plant was made in Cycle Tempo 5.0. There were designed all apparatus and basic parameters. The program is capable of computing the rest of parameters (temperature, pressure, mass flow, enthalpy, etc.) in every point of the steam system.

5.3. Steam cycle without CCS technology: Phase two

5.3.1. Compared and verified model

The next step was the design of the reference power plant in a more complex computer program. As that was choose the computer software gPROMS. The gPROMS is the Advanced Process Modelling environment. gPROMS models are used to explore the design or operational decision space to provide accurate predictive information for decision support. For this thesis was used advanced package gCCS. That program using for calculations slightly different way. The Cycle Tempo is only “numerical computer program”. Unlike Cycle Tempo, the gCCS also respects the physical nature of the calculations, so both programs work with different approaches to calculations.

Although values from computer program Cycle Tempo and gCCS aren´t identically, the differences are very small negligible. The delivered gross power is identical, that was first target. The final and most meaningful comparable value are net efficiency. The value from gCCS is higher by 0.12 percentage point so that we can declare the models as the identical. Although other variables are entered, both models have the same result.

5.4. Flue gas cleaning

The previous model is necessary for power parameters. For implementation of CCS technology post-combustion is needed to add flue gas cleaning. How is written above, the reference unit is designed as environmentally friendly as possible. To the model of the power cycle was added flue gas cleaning technologies as they are used in reference real power plant Ledvice. These technologies are:

- Electrostatic precipitator (ESP)
- Flue Gas Desulphurisation unit (FGD)

The ESP and FGD are secondary step how to reduce emission of dust and Sulphur oxides. For reducing emission of NOx is using primary measures. Primary measures are intended to reduce NOx formation during the combustion process. Considering the nature of the combustion and its subsequent modifications, we can say that the primary measures are simple. We can combine them differently.

The Ledvice power plant is built to meet the rigorous environmental standard. The new power plants in European union must meet requirements of Best Available Techniques (BAT). This standard describes by using BAT Reference Documents (BREF) the best available technologies for elected type of device. The purpose of these standards is an effort continual reduce emission limits in compliance with technical developments. The following emission values are mandatory for Ledvice power plant from the time of commencement of construction (Figure 8).

NO_x	< 200	mg/Nm^3 (6% O_2)
SO_x	< 150	mg/Nm^3 (6% O_2)
CO	< 200	mg/Nm^3 (6% O_2)
Ash particle content	< 20	mg/Nm^3 (6% O_2)

Table 5 - Guaranteed emission values of reference power plant [40]

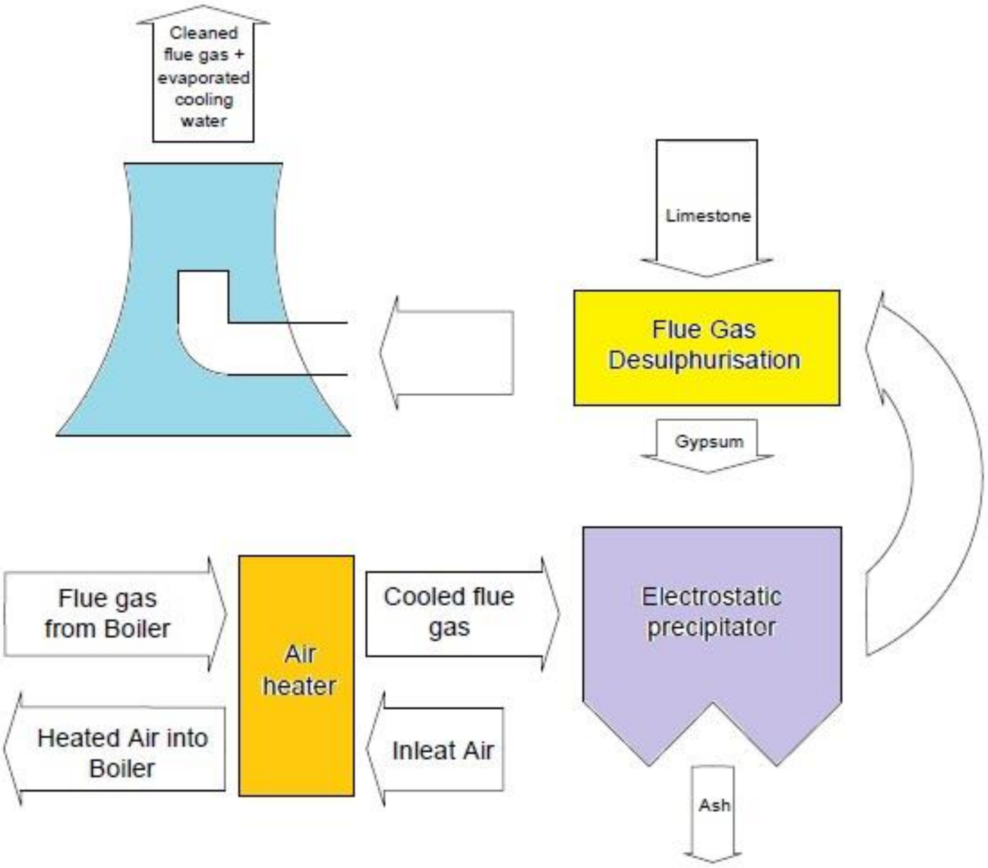

Figure 9- Scheme of flue gas cleaning

All flue gas cleaning technologies described above (the model is in Figure 9) are also used in reference plant, without CCS, but for implementation of CCS technology are required different values of the monitored elements in the flue gas.

5.3.1. Electrostatic precipitator

The first technology when flue gas leave boiler and primary emission reduction is electrostatic precipitator. An electrostatic precipitator is a filtration device that removes fine particles, like dust and smoke, from a flowing gas using the force of an induced electrostatic charge minimally impeding the flow of gases through the unit. For a coal-fired boiler the collection is usually performed downstream of the air preheater at about 160 °C which provides optimal resistivity of the coal-ash particles. For some difficult applications with low-sulphur fuel hot-end units have been built operating above 370 °C. That is case of Ledvice. The operation temperature is there around 350°C. The removal efficiency is over 99%.

For calculation in this thesis was used the default model from gCCS library. The Electrostatic precipitator model removes the particulate matter from an inlet gas stream. The main inputs of this model are the outlet ash concentration (20 mg/Nm^3) or the removal efficiency and pressure drop of the unit (20 Pa). The model estimates the power required to perform this operation. The exact properties of ESP unit were calculated by computer model of reference power plant (Table 5).

Inlet flue gas flow rate	668.98	kg/s
Power	0.94	MW
Removal efficiency	99.96	%
Outlet ash concentration	20.00	mg/Nm^3

Table 6 - Parameters of ESP unit

5.3.2. Flue gas desulphurisation

The flue gas when leave ESP flowing to desulphurisation unit. It is a set of technologies used to remove sulfur dioxide (SO_2), from exhaust flue gases of fossil-fuel power plants. Sulfur dioxide is now being removed from flue gases by a variety of methods. Below are common methods used:

- Wet scrubbing using a slurry of alkaline sorbent, usually limestone or lime, or seawater to scrub gases
- Spray-dry scrubbing using similar sorbent slurries
- Wet sulfuric acid process recovering sulfur in the form of commercial quality sulfuric acid
- SNOX Flue gas desulphurisation removes sulfur dioxide, nitrogen oxides and particulates from flue gases;
- Dry sorbent injection systems that introduce powdered hydrated lime (or other sorbent material) into exhaust ducts to eliminate SO2 and SO3 from process emissions.

The following reaction takes place in the FGD unit:

$$CaCO_3 + 1/2O_2 + {}_2H_2O + SO_2 \rightarrow CaSO_4{:}{}_2H_2O + CO_2$$

Wet limestone scrubbing is use for the flue gas desulphurisation in Ledvice power plant. It having the highest operation effectiveness (around 90%). Flue gasses with almost all dust particles caught in the electrostatic precipitators are routed to the scrubber, where they are cleaned by limestone slurry at four spray levels. Limestone slurry reacts with the Sulphur oxides, binds them and is transformed into gypsum slurry. The remaining ash in flue gasses is caught by the spray levels, along with other harmful compounds, such as those of fluorine and chlorine. Cleaned flue gases are routed into the cooling tower where they are discharged into the atmosphere together with evaporated cooling water. [40]

Figure 10- The FGD unit before completion in Ledvice [44]

In Figure 11 is showed schematic model of FGD unit in computer model and for comparison in Figure 10 is real FGD unit in Ledvice.

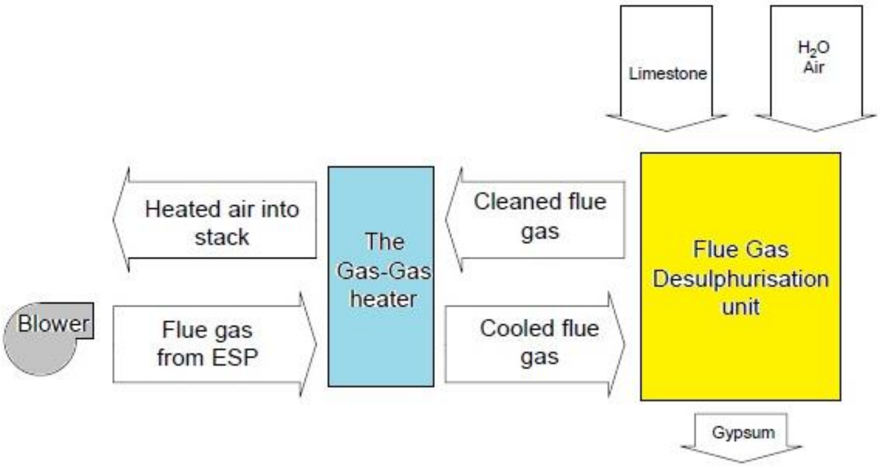

Figure 11- The scheme of FGD unit used in computer model

For equation model in this thesis was used again model from gCCS library. The FGD removes the Sulphur dioxide in the flue gas to a certain content specification. The model calculates the power and material (e.g. limestone) required for the operation. The exact properties of FGD unit were calculated by computer model of reference power plant (Table 6).

Inlet flue gas flowrate	633.65	kg/s
Efficiency	95.70	%
Inlet SO_2 concentration at 6% dry O_2	3502.00	mg/Nm^3
Outlet SO_2 concentration at 6% dry O_2	150.00	mg/Nm^3
Power required	3.00	MW
Limestone slurry flowrate	10.36	kg/s
Inlet water flowrate	31.42	kg/s
Inlet O_2-source flowrate	2.93	kg/s
Gypsum slurry flowrate	37.99	kg/s
Gypsum product flowrate	6.27	kg/s

Table 7 - Parameters of FGD unit

5.5. Reference power plant with flue gas cleaning

After inclusion technology of flue gas cleaning with steam power cycle is reference plant completed. This thesis will compare the impact of CCS technology to reference cycle exactly with this completed cycle. Such technology meets the requirements of BAT standard but for implementation of Post-combustion CCS technology is necessary to check and verified guaranteed emission values. The emission limit values for CCS technology are different than emission limit for BAT standard.

The flue gas cleaning has a considerable energy consumption and every added technology, including CCS technology, significantly increases power consumption (Table 8).

	Reference plant (without CCS)
Boiler heat output [MW]	1300.00
$\dot{m}_{Working\ fluid}$ [kg/s]	467.65
P_e [MWe]	660.00
$\dot{m}_{Fuel}$ [kg/s]	126.00
Flue gas consumption:	
Feed water pumps [MWe]	22.60
Cooling water pump [MWe]	6.79
Flue gas consumption:	
ESP [MWe]	0.94
FGD [MWe]	3.00
SCR [MWe]	0.00
Air Blower [MWe]	4.58
Flue gas Blower [MWe]	11.00
CCS consumption:	
Total auxiliary load [MWe]	48.91
Net electrical power [MWe]	611.09
η_{GROSS} [%]	46.20
η_{NET} [%]	42.78

Table 8 - List of technology consuming energy and energy assessment of reference power plant

For fair comparisons impact of CCS technology to reference steam power plant is needed show these two cycle, complete reference power plant with flue gas cleaning and complete CCS technology with added technology for flue gas cleaning.

The flue gas cleaning has a natural effect on the net efficiency of the whole cycle. In Table 8 is showed assessment of reference power plant taking into account the impact of the added technology for flue gas cleaning. If is compared the value of net efficiency from Table 5 in chapter 5.3.1. and same value from Table 8, the difference in values of net efficiency is 1.38 % or the flue gas cleaning decrease the net efficiency of reference power plant by 1.38 %.

At this point is last option to verification of computer model used in this thesis. The computer model has the same design as real power plant and it is based on the parameters from the basic scheme of reference power plant. There was stated only some parameters, so for completion of computer model was necessary to calculate and establish the rest of the required parameters. It is possible to compare official net efficiency value of real Ledvice power plant and final efficiency of reference power plant, which is 42.5 % [29], respectively 42.78 % [Table 8]. The difference of only 0.28 percentage point is acceptable and the computer model is identical. The print screen of complete model is in Attachment 5.

5.6. Steam power plant with CCS technology

Post-combustion CCS technology is one of the leading technologies aimed at significantly reducing CO_2 emissions from coal-fired power plant. This thesis examines using of ammonia scrubbing technology. Ammonia has several advantages: it is low-cost, less corrosive, and does not degrade in the presence of O_2 and other species in the flue gas. It has a high CO_2 removal capacity and low regeneration energy and can capture multiple components (e.g. NO_x, SO_x, CO_2, and Hg). Ammonia can also be used to produce value-added products such as ammonium sulphate (via sulphite oxidation) and ammonium nitrate (via nitrite oxidation), which can be used as fertilizers. [25]

Since ammonia is volatile, it partly evaporates to the flue gas in the absorber and is also present in the CO2 product stream at the stripper gas outlet. This causes ammonia loss and requires ammonia make up. The combination of these properties makes ammonia scrubbing an appropriate method for separating CO_2 in the conditions of the Czech Republic.

5.6.1. Model of ammonia scrubbing

The flue gas enters an absorption column in which it is fed with a counter current working fluid into which the captured component (CO_2) is absorbed. The saturated solvent is then passed to the second column where the absorbed component (CO_2) from the rich solvent is expelled and the regenerated solvent is returned to the absorption column. The principle is shown in Figure 12 and Table 9. The basic reaction in the aqueous solution can be described as follows:

$$NH_3 + H_2O + CO_2 = NH_4HCO_3$$

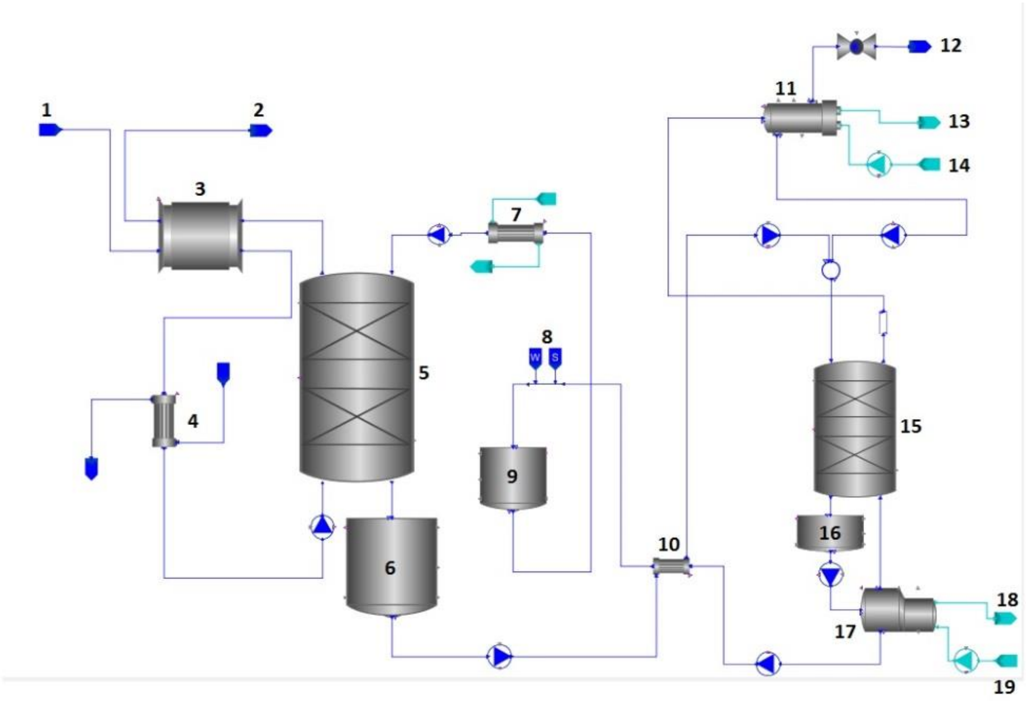

Figure 12- Model of abortion unit for CO_2 separation

1	Inlet flue gas
2	Outlet flue gas
3	Regeneration Gas-Gas heater
4	Flue gas cooling
5	Absorber
6	Rich absorber tank
7	Heating of makeup solvent
8	Make-up solvent
9	Lean tank
10	Lean/Rich heat exchanger
11	Condenser
12	CO_2 to compression
13	Inlet cooling water
14	Outlet cooling water
15	Stripper/Regenerator
16	Stripper tank
17	Reboiler
18	Outlet condensate to deaerator
19	Inlet steam

Table 9 - List of equipment in CCS separation unit

The model of ammonia scrubbing (Figure 10) designed in gCCS is used for capture of CO_2. This design is inspired by reference example from gCCS library and usual designs in articles, models and pilot unit. In CCS unit is consumed energy in many ways:

- Cooling of flue gas
- Regeneration of solvent in reboiler by steam
- Pumps
- Heating of make-up

The previous research develops the wide range of values for energy requirement per tonne of captured CO_2. In equations of impact CCS technology post-combustion on reference power plant is used the amount of energy need for regeneration of solvent as 1.1 GJ/t_{CO_2}, which is at the bottom edge of the researched range. Nevertheless, that value includes only the capture process in the absorber, regeneration of ammonia in stripper and reboiler, cooling consumption in condenser and consumption for the preparation of make-up ammonia. Another consumption as a cooling of flue gas before capture and compression captured CO_2 must be calculated.

The amount of energy consumed per tonne of separated CO_2 from the top edge of researched values is 2.3 GJ/$t_{CO2.}$ In the studies investigated is not what is included in this value. Probably, this value includes all consumption with the CCS technology as a cooling and compression.

5.6.1.1. Cooling consumption

Although, the cooling unit in Figure 10, marked as point 4, is shown as one equipment as a matter of fact that include two equipment. After flue gas desulphurisation has flue gas temperature over 200°C, but it is too high for CCS technology post-combustion with ammonia scrubbing. This technology required temperature usually from 0°C to 20°C. This thesis defined 5°C as designed temperature for entering to ammonia capture unit, so the flue gas must be cooled. The design of modelled power plant use three steps:

- Recuperation of flue gas temperature (208°C → 59°)
- Water cooling cycle (59°C→ 30°C)
- Compressor cooling (30°C → 5°C)

Recuperation is performed by the analogy of Gas-Gas heater. It is in the cycle for reduction of inlet flue gas temperature and current increase outlet flue gas temperature after CO_2 before entering to the stack. The other will be a cooling tower circuit (or fan tower). However, it is not possible to reach the cooling water temperature near 0°C - in the summer the maximum is around 23°C. The main consumer is there water pump for circulation of cooling water. The last step before capture process is compressor cooling. Compressor cooling is required to achieve lower temperatures. We assume the use of compressor cooling with ammonia filling. Typically, a technology with a vapour temperature of about -12 ° C can be encountered. This is entirely sufficient for the needs of this thesis. The temperature of flue gas needs to be lower by 25°C. For flue gas flowrate 642 kg/s was determined cooling power 17.31 MW. Complete energy consumption of cooling is in Table 10.

Water cooling consumption	0.97	MWe
Compressor cooling consumption	5.77	MWe

Table 10 - List of cooling consumptions

5.6.1.2. Consumption of CCS unit

At this point is flue gas cooled to 5°C, which is required temperature for successful separation of CO_2 by ammonia. To determine the energy demands of the process has been used environment-mentioned computer program gCCS. Energy demand is influenced by many parameters They are used typical values based on previous research. Key inputs are the capture efficiency of the plant and the specific energy requirement (Table 11).

The specific energy requirement	1.1	2.3	GJ/t $_{CO2}$
The CO_2 capture rate	90	90	%
Purity of the outlet CO_2 stream	95	95	%
The CO_2 outlet temperature	30	30	°C
Outlet flue gas temperature	5	5	°C

Table 11 – Input parameters

The greatest influence of CCS technology has a steam flow for reheating of ammonia. This consumption is defined by specific energy requirement from Table 11. Based on previous research and possibilities reference power cycle is used steam with the following parameters:

- Temperature: 140°C
- Pressure: 3.615 bar

Computer simulation in gCCS determined following outlet parameters of CO_2 stream and steam demand:

The specific energy requirement	1.1	2.3	GJ/t $_{CO2}$
Outlet CO_2 flowrate	119.89	119.89	kg/s
Outlet CO_2 stream temperature	30.00	30.00	°C
Outlet CO_2 stream mass fraction ("CO_2")	0.95	0.95	kg/kg
Outlet CO_2 stream mass fraction ("H_2O")	0.05	0.05	kg/kg
Steam demand	61.50	128.59	kg/s

Table 12 – Output parameters of CCS unit

Steam flow exits from an LP steam turbine section and is returned to deaerator. The heat requirement of CCS unit requires 61.5 kg/s, respectively 128.59 kg/s steam with defined parameters. It has a huge influence on gross power electricity output of reference power plant. The balancing of steam through LP steam turbines was also necessary due to a significant steam flow drop on one of two parallel LP stream. The ratio of steam flow between two parallel LP steam turbines is 0.587: 0.413. In second case (2.3 GJ/t CO_2) this ratio is 0.675: 0.325.

5.6.1.3. Compression consumption

The captured CO_2 is being compressed for another treatment. After compression to 116 bar CO_2 can leave the area of the power plant and can be transported to storage or utilisation area. In library of gCCS is defined high-level compression unit defined for this purpose. The Compression unit model is a configurable high-level model of compression train flowsheet. Its purpose is to allow full compression train, using sensible design parameters, without needing to build a fully-detailed flowsheet in computer software. For a defined CO_2 stream, design inlet pressure, design outlet pressure and drive speed, the model calculates the number of identical trains operating in parallel, the number of sections in series and both size and pressure ratio of each compressor section based on heuristic rules. With these, the overall polytrophic efficiency and total compression power are calculated.

Mass flowrate	119.80	kg/s
Pressure	110	bar
Temperature	40	°C
Number of trains in parallel	2	-
Number of sections in series	7	-
Total compression power	43.04	MWe

Table 13 – Output parameters of compression unit

5.6.2. Impact assessment of CCS technology

It was described many times in previous chapters; the CCS technology has a huge influence to the power plant. The energy consumptions divide for part shows considerable predominance of demand on compression and capture unit. The results are delivered by gCCS (Table 14).

The specific energy requirement	1.1	2.3	GJ/t $_{CO2}$
Electrical consumption of cooling flow gas before CCS	6.74	6.74	Mwe
Reduce gross power of power plant	35.892	75.28	Mwe
Electrical consumption of compression	43.04	43.04	Mwe
Summary	**85.675**	**125.063**	**Mwe**

Table 14 – Electricity consumption of technology in CCS

The overall impact of inclusion CCS technology post-combustion into cycle of reference power plant is described in Table 15. The difference in net efficiency with and without CCS technology is 5.94 respectively 8.68 percentage points. This value is in a range of expected results after research in the first part of this thesis.

	Reference plant (without CCS)	Power plant with CCS	Power plant with CCS
The specific energy requirement [GJ/t CO_2]	0	1.1	2.3
Boiler heat output [MW]	1300.00	1300.00	1300.00
$\dot{m}_{\text{Working fluid}}$ [kg/s]	467.65	467.65	467.65
P_e [MWe]	660.00	624.10	584.72
$\dot{m}_{\text{Fuel}}$ [kg/s]	126.00	126.00	126.00
Flue gas consumption:			
Feed water pumps [MWe]	22.60	22.47	22.37
Cooling water pump [MWe]	6.79	5.98	5.28
Flue gas consumption:			
ESP [MWe]	0.94	0.94	0.94
FGD [MWe]	3.00	3.00	3.00
SCR [MWe]	0.00	0.00	0.00
Air Blower [MWe]	4.58	4.58	4.58
Flue gas Blower [MWe]	11.00	11.00	11.00
CCS consumption:			
Flue gas cooling	0.00	6.74	6.74
CO_2 compression	0.00	43.04	43.04
Total auxiliary load [MWe]	48.91	97.75	96.95
Net electrical power [MWe]	611.09	526.35	487.77
η_{GROSS} [%]	46.20	43.69	40.93
η_{NET} [%]	42.78	36.84	34.14

Table 15 – Comparison of reference power plant without and with CCS technology

The aim of this chapter is the assessment of impact CCS technology post-combustion to reference power plant. The fundamental problem is to determine right value of energy required for one tonne separated CO_2. The previous research develops the wide range of values for this value. Every used study included in this value different consumption and is widely dependent on the other properties considered in a particular study (concentration of NH_3 in solvent, concentration of CO_2 in the flue gas, the design of CCS unit, CO_2 capture rate, etc.). After consultation with supervisor and consultant of this thesis was for later equation choose value 1.1 GJ/t_{CO2} as a more appropriate value. To determine the exact impacts is necessary accurately determine the required energy for solvent regeneration.

5.7. Modified design for new BAT limits

This thesis evaluates in previous chapter impact of implementation of CCS technology to reference power plant working with emission standard from the start of construction. In follows chapter will be shown the influence of the new BAT standards for existing emission eminent.

5.7.1. Emission limits by BAT

The power plant Ledvice belongs according to BAT conclusion scope to category 1.1: Combustion of fuels in installations with a total rated thermal input of 50 MW or more, only when this activity takes place in combustion plants with a total rated thermal input of 50 MW or more. For existing plant in this category are the following values are binding:

NO_x	< 150	mg/Nm^3 (6% O_2)
SO_x	< 130	mg/Nm^3 (6% O_2)
CO	< 100	mg/Nm^3 (6% O_2)
Ash particle content	< 8	mg/Nm^3 (6% O_2)

Table 16 - Guaranteed emission values for reference power plant by BAT

5.7.2. Modification of reference power plant design

The model of the schematic power plant was adjusted due to implementation of the post-combustion technology and emission limits by new BAT. The used technology for flue gas cleaning are:

- Electrostatic precipitator
- Flue Gas Desulphurisation unit
- The Selective Catalytic Reduction

The first two technology of flue gas cleaning was already described in chapter 5.3.1. and 5.3.2. They will be only modified so here is no need to re-engage them.

5.7.3. Selective catalytic reduction unit

In order to meet the new limits, it is necessary to add Selective Catalytic Reduction unit. The today valid limits no need SCR unit, because the primary drive is sufficient. The SCR unit is a means of converting nitrogen oxides, also referred to as NO_x with the aid of a catalyst into diatomic nitrogen (N_2) and water (H_2O).

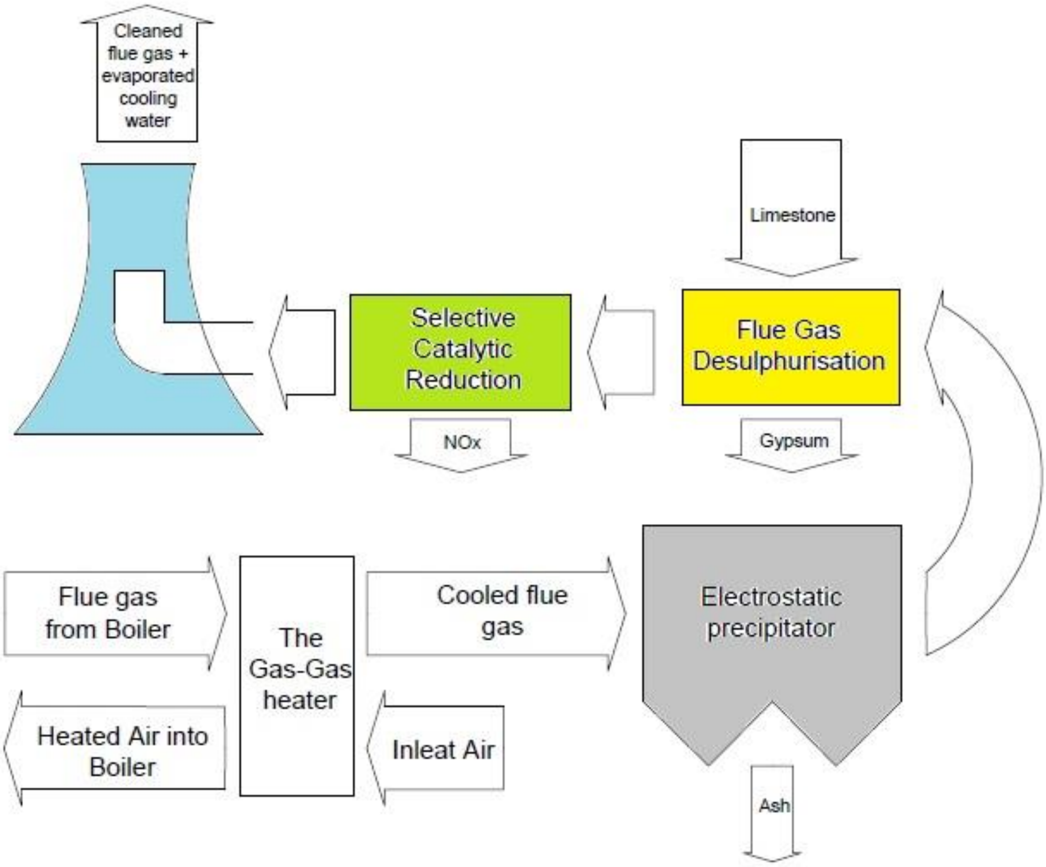

Figure 13- Model of modified flue gas cleaning without CCS unit

For modified model was selected combination of SCR added between FGD unit and CCS unit. This design is suitable later implementation to existing power plant. The disadvantage of this combination is a heating duty to flue gas. The temperature of flue gas on exit from FGD unit is over 210°C, but operation temperature of SCR is around

300°C. Usually is SCR unit placed right behind the boiler. It using high temperature before flue gas cooling but in this case, is SCR equipment destroyed by the flue gas stream with high content of ash. Those problems are eliminated in case described in Figure 13.

The computer software sCCS has in his library predefined model of SCR unit. The model estimates the reagent stream requirements based on a mass balance and the form of the ammonia-based reagent (aqueous). Since the ammonia-based reagent is diluted with air to assist with transport, flow control and injection, the model internally calculates the required air flow. The outlet temperature and composition are also calculated by the model. Due to the methodology of calculation (predefined parameters of the boiler balancing including the flue gas composition calculation), it was not possible to carry out the planned balance calculations for the influence of the change of the emission limits on the block power. A model with modified parameters (flue gas composition: Mass flow (NO_x) = 220 mg/ Nm^3) was created for the idea so that the influence adjusting of this technology to meet the limits can be identified. Outputs from this model give only informative data about the influence of this technology, but regarding the precision, analysis should be sufficient. Table 17 shows key parameters of SCR unit.

NH_3 stream mass flowrate	3.77	kg/s
NOx removal efficiency	36.38	%
Outlet NOx concentration	150.00	mg/Nm^3
Inlet flow	643.00	kg/s
Outlet flow	646.70	kg/s

Table 17 - Parameters of SCR unit

The SCR unit has, as every technology, energy demand. In this case is consumed heat energy by steam. The steam flow (4.4 kg/s) comes from the last stage of IP steam turbine with the temperature 323°C and pressure 6.7 bar.

5.7.4. Modified CCS unit

The implementation of BAT standard has also influence on CCS unit. For assessment was choose value of required energy 1.1 GJ/t $_{CO2}$. In output parameters (Table 18) are visible difference in CO_2 flow rate and steam demand.

The specific energy requirement	1.1	GJ/t $_{CO1}$
Outlet CO_2 flowrate	114.79	kg/s
Outlet CO_2 stream temperature	30.00	°C
Outlet CO_2 stream mass fraction ("CO_2")	0.95	kg/kg
Outlet CO_2 stream mass fraction ("H_2O")	0.05	kg/kg
Steam demand	58.88	kg/s

Table 18 – Output parameters of CCS unit

The difference in output parameters has naturally influence to power load of CCS technology. The energy for cooling is the same (the difference is negligible), but electricity consumption of compressor and less reduction of gross power is evident.

The specific energy requirement	1.1	GJ/t $_{CO1}$
Electrical consumption of cooling flow gas before CCS	6.74	Mwe
Reduce gross power of power plant	34.35	Mwe
Electrical consumption of compression	41.26	Mwe
Summary	**82.35**	**Mwe**

Table 19 – Electricity consumption of technology in CCS

5.7.5. The assessment of BAT standard

The modified design of reference power plant has couple basic change compared with the original reference power plant:

- Steam flow to SCR unit
- SCR unit
- Second ESP unit

The differences best summarise following comparison (Table 20). There are together results version for original power plant, reference power plant with applied BAT standard and version of BAT and CCS unit.

	Reference plant (without CCS)	Reference plant (without CCS) BAT standard	Power plant with CCS BAT standard
The specific energy requirement [GJ/t CO_2]	0	0	1.1
Boiler heat output [MW]	1300.00	1300.00	1300.00
$\dot{m}_{\text{Working fluid}}$ [kg/s]	467.65	467.65	467.65
P_e [MWe]	660.00	657.20	621.15
$\dot{m}_{\text{Fuel}}$ [kg/s]	126.00	126.00	126.00
Flue gas consumption:			
Feed water pumps [MWe]	22.60	22.58	22.48
Cooling water pump [MWe]	6.79	5.99	5.98
Flue gas consumption:			
ESP [MWe]	0.94	0.98	0.98
FGD [MWe]	3.00	5.00	5.00
SCR [MWe]	0.00	0.00	0.00
Air Blower [MWe]	4.58	4.58	4.58
Flue gas Blower [MWe]	11.00	14.80	14.80
CCS consumption:			
Flue gas cooling	0.00	0.00	6.74
CO_2 compression	0.00	0.00	43.04
Total auxiliary load [MWe]	48.91	53.93	103.60
Net electrical power [MWe]	611.09	603.27	517.55
η_{GROSS} [%]	46.20	46.00	43.48
η_{NET} [%]	42.78	42.23	36.23

Table 20 – Comparison of reference power plant without and with CCS technology

Due to complication with the predefined model of boiler described above, is this chapter rather informative. For an accurate comparison, would by necessary make the own design of boiler or use different computer software. Nevertheless, the final impact would be not very different.

6. Economy evaluation

In previous chapter was defined technical part of implementation of technology CCS. In this chapter is described economic assessment. For economical evaluation of variations with CCS and without CCS was chosen three important indexes which are shoved below:

- Cost of capture [\$/tCO_2]
- Cost of electricity [\$/kWh]
- Avoided cost of the capture [\$/tCO_2]

All the cost used from external source where transfer to \$ (dollar) in accordance with exchange rate from the date of origin of the source. In this thesis is used similar process for economical assessment which is usual in another assessment, thesis and papers on this topic. It can provide comparison between different methods and technologies of CCS.

6.1. Electricity cost

The cost of electricity point of view was compared two cases. First one is economical evaluation of the power plant without CCS (reference power plant). The second one case was used as reference power plant with added CCS technology.

For power plant without CCS was characterize by four inputs:

- Capital cost [\$/kW]
- Operation and maintenance cost [\$/kW]
- Heat rate based on LHV [kJ/kWh]
- Cost of emission permits [\$/tCO_2]

Their values are show in Table 21. From these three aspects, the cost of electricity for reference power plant is calculated. In the second case is estimated cost of the electricity from power plant with CCS. In this case are estimated only changes of the previous four parameters:

- Incremental capital cost [$/kW]
- Increment of operation and maintenance cost [$/kW]
- Increment of the heat rate [kJ/kWh]
- Reduction of the emission permits cost [$/tCO$_2$]

		Reference power plant	CCS with flue gas recirculation
Capital cost [$/kW]		3.636 [41]	5.084 [41]
Operation and maintenance cost	Fixed [$/kW-year]	42.10 [41]	70.0 [41]
	Variable [$/MWh]	4.60 [41]	7.10 [41]
Cost of emission permits [$/tCO$_2$]		4.38 [42]	
Fuel price [$/t]		22.36 [43]	

Table 21 - Basic inputs for estimation of the power plant cost

The equation for the electricity calculation is presented below:

$$COE = \frac{\sum_{t}^{15} \frac{IC_t + OM_t + FE_t + EP_t}{(1+dr)^t}}{\sum_{t}^{15} \frac{GE_t}{(1+dr)^t}}$$

COE - *Cost of electricity [\$/kWh]*

IC_t - *Investment expenditures for given year [\$/yr]*

OM_t - *Operation and maintenance expenditures for given year [\$/yr]*

FE_t - *Fuel expenditures for given year [\$/yr]*

EP_t - *Cost of emission permits [\$/yr]*

dr - *Discount rate [-]*

GE_t - *Generated electricity for given year [kWh-yr]*

t - *Year [-]*

For calculation of COE is assumed that capital cost of the power plant will be provided by credit which is provided for fifteen years. Discount rate (*dr)* is assumed to be fixed for this period and it is 6%. I estimated mean value for operation and maintenance cost over the 15 years. This thesis assumed the amount of fuel and annual operating hours won´t change during the life time the price of fuel is fixed.

These values are added to previous three parameters and stated in the Table 22. The value of PE_t is reduced in this case because the emission of CO_2 is much lower. Cost of electricity is calculated from the same equation as in the first case (the equation is showed above) but the values of IC_t, OM_t, FE_t were increased by the increments and as generated electricity *(GE)* was used value from the model of the power plant with CCS. This thesis assumed same annual operations hours, 6000, as for the reference power plant.

6.2. Cost of capture

Cost of capture (COC) is defined as difference between cost of the electricity captured COE_{CCS} and cost of the electricity in reference power plant COE_{REF} divided by amount of the captured carbon dioxide CO_{2CAP}. The formula for calculation of this cost is below:

$$COC = \frac{(COE_{CCS} - COE_{REF}) \cdot GE_{CCS}}{CO_{2CAP}}$$

COC - *Cost of capture [$/t]*

COE_{CCS} - *Cost of electricity in power plant with CCS [$/kWh]*

COE_{REF} - *Cost of electricity in reference power plant [$/kWh]*

GE_{CSS} - *Generated electricity in power plant with CCS [$/kWh]*

CO_{2CAP} - *Amount of the captured carbon dioxide*

6.3. Avoided cost of the capture

The capture cost give the information about the cost of the capture in power plant with CCS it does not dedicate additional CO_2 which is produced because of the capture process. In Figure 12 is evident increment of the produced CO_2 because of capture process. In this are two power plants with same net electricity output. The power plant with CCS technology needs more fuel and therefore it produces more CO_2 because of the capture process. This additional amount of the CO_2 is not considered in avoided cost calculation.

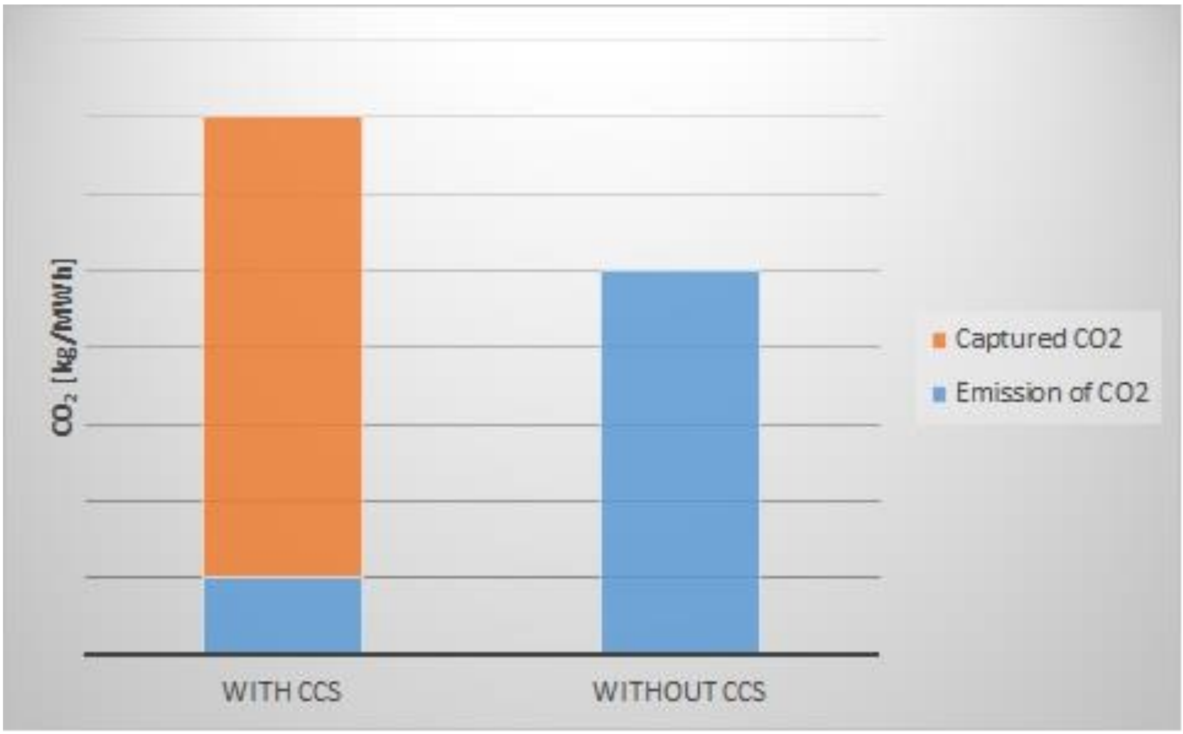

Figure 14 - Comparison of CO2 production from power plants with same power output (with and without CCS)

Avoided cost of capture can be defined as a ratio of difference between electricity cost in the CCS power plant and reference power plant and difference between intensity of CO_2 production of reference power plant I_{REF} and CCS power plant I_{CCS}.

$$AC = \frac{COE_{CCS} - COE_{REF}}{I_{REF} - I_{CCS}}$$

AC	-	*Avoided cost of capture [$/t]*
I_{REF}	-	*Intensity of CO_2 production of reference power plant [t/kWh]*
I_{CCS}	-	*Intensity of CO_2 production of CCS power plant [t/kWh]*

Power plant	Cost of electricity [\$/kWh]	Avoided cost of capture [\$/t_{CO_2}]	Cost of capture [\$/t_{CO_2}]
Reference power plant	0.075	-	-
Power plant with flue gas recirculation	0.108	51.314	43.078

Table 22 – Estimated cost of electricity

7. Design of heat exchanger

7.1. Selected heat exchanger

Feed water heater is heat exchanger which surface is used for heat transfer. The heat is transferred from the flue gas to the feed water. This transfer is realized almost solely by the convection. In this thesis is designed low-pressure feed water heater. The position of the economizer is marked in Attachment 3 as an equipment 18. This heat exchanger is simple heat exchanger without de-superheating zone.

7.2. Design of feed water heater

The shell & tube design with two passes is used as a feed water heat exchanger. Where on the shell side is condensing saturated vapour and on the tube side feed water is heated. The basic schema of heat exchanger is shown in the Figure 15 and known fluid conditions are mentioned in Table 23 and Table 23 . In the design of shell & tube heat exchanger were neglected pressure losses and strength calculations. The thermodynamic properties of liquids were taken from X STEAM TABLES. [47]

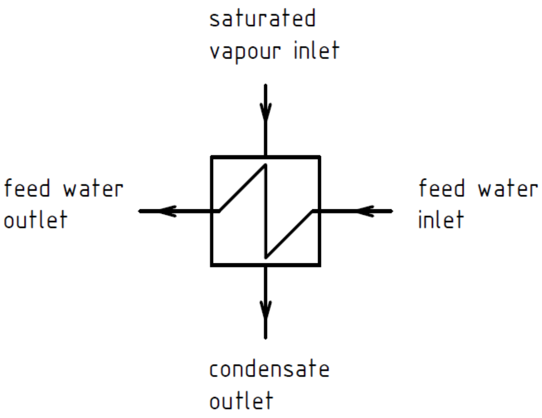

Figure 15 – Basic scheme of heat exchanger

Feed water		
$t_{c,in}$	52.06	°C
$t_{c,out}$	75.12	°C
p_c	12.74	bar
m_c	319.95	kg/s
$i_{c,in}$	219.03	kJ/kg
$i_{c,out}$	315.47	kJ/kg
Δi_c	96.44	kJ/kg

Table 23 – Feed water properties

Saturated vapor/condensate		
t_h	80.12	°C
p_h	0.48	bar
m_h	13.37	kg/s
$i_{h,in}$	2643.21	kJ/kg
$i_{h,out}$	335.44	kJ/kg
$i_{h,fg}$	2307.77	kJ/kg

Table 24 – Saturated vapor/condensate properties

7.2.1. Heat transfer calculation

$$\dot{Q} = \dot{m}_c \cdot \left(i_{c,out} - i_{c,in}\right) = 319.95 \cdot \left(315.47 - 219.03\right) = 30857.54 kW$$

$$\dot{Q} = \dot{m}_h \cdot \left(i_{h,in} - i_{h,out}\right) = 13.37 \cdot \left(2643.21 - 335.44\right) = 30857.54 kW$$

7.2.2. Number of tubes calculation

Tube - inner diameter: $d_1 = 36$ mm

Tube - outer diameter: $d_2 = 40$ mm

Tube thermal conductivity: $\lambda = 120$ W/(m·K)

Water velocity: w = 1 m/s

Pattern of tube distribution in the heat exchanger is shown in the Figure 16.

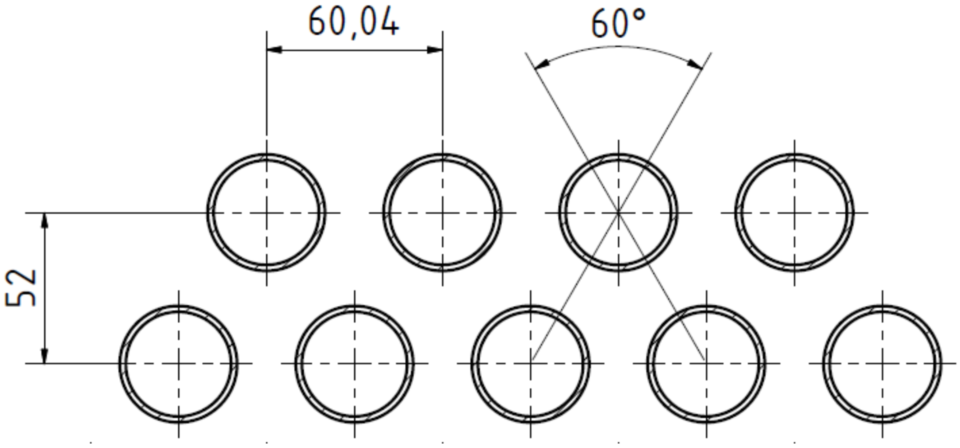

Figure 16 - Pattern of tube distribution in the heat exchanger

Mean water temperature:

$$t_{c,mean} = \frac{t_{c,in} + t_{c,out}}{2} = \frac{52.06 + 75.12}{2} = 63.59°C$$

Water specific volume:

$$v = f\left(p_c ; t_{c,mean}\right) = f(12.74bar;63.59°C) = 0.0010185\, m^3 / kg$$

Water flow section:

$$A_c = \frac{\dot{m}_c \cdot v}{w} = \frac{319.95 \cdot 0.0010185}{1} = 0.326 m^2$$

Number of tubes:

$$n = \frac{4 \cdot A_c}{\pi \cdot d_1^{\ 2}} = \frac{4 \cdot 0.326}{\pi \cdot 0.036^2} = 320.15 \rightarrow 367$$

Selected number of tubes in heat exchanger is 367 and they are in two pass order ($n_p = 2$).

Total number of tubes:

$$n_{total} = n \cdot n_p = 367 \cdot 2 = 734$$

Real water flow section:

$$A_{c,real} = \frac{\pi \cdot n \cdot d_1^{\ 2}}{4} = \frac{\pi \cdot 367 \cdot 0.036^2}{4} = 0.374 m^2$$

Real water velocity:

$$w_{real} = \frac{\dot{m}_c \cdot v}{A_{c,real}} = \frac{319.95 \cdot 0.0010185}{0.374} = 0.872 m/s$$

7.2.3. Overall heat transfer coefficient calculation

- ***Water side:***

Prandtl number of water:

$$\Pr_c = f\left(p_c; t_{c,mean}\right) = f\left(12.74 bar; 63.59°C\right) = 2.826$$

Dynamic viscosity of water:

$$\mu_c = f\left(p_c; t_{c,mean}\right) = f\left(12.74 bar; 63.59°C\right) = 442.48 \cdot 10^{-6} Pa \cdot s$$

Thermal conductivity of water:

$$\lambda_c = f\left(p_c; t_{c,mean}\right) = f\left(12.74 bar; 63.59°C\right) = 0.655 W/\left(m \cdot K\right)$$

Reynolds number:

$$\mathrm{Re}_c = \frac{w_{real} \cdot d_1}{\mu \cdot v} = \frac{0.872 \cdot 0.036}{442.48 \cdot 10^{-6} \cdot 0.0010185} = 69684$$

The Nusselt number calculation is using Dittus- Boelter equation (4·10^4 < Re < 10^6 and 0.3 < Pr < 300), which is less accurate for liquids with high high Prandtl numbers and for more precise calculations of fully developed heat transfer in turbulent liquid flow. [48]

$$Nu_c = 0.0225 \cdot \mathrm{Re}^{0.795} \cdot \mathrm{Pr}^{0.495} \cdot \exp\left\{-0.0225 \cdot [\ln(\mathrm{Pr})]^2\right\}$$
$$Nu_c = 0.0225 \cdot 69684^{0.795} \cdot 2.826^{0.495} \cdot \exp\left\{-0.0225 \cdot [\ln(2.826)]^2\right\}$$
$$Nu_c = 260.18$$

Heat transfer coefficient on water side:

$$\alpha_c = \frac{Nu_c \cdot \lambda_c}{d_1} = \frac{260.18 \cdot 0.655}{0.036} = 4731.91 W/\left(m^2 \cdot K\right)$$

- ***Steam / condensate side***

During condensation, the working fluid (saturated vapor) changes its state from gas to liquid. In the case of surface regeneration heaters, it is in most cases film wise condensation. Here, the condensed liquid forms a continuous liquid film on the outside of a around tube. The condensed liquid moves around the tube same direction as gravitational force.

Condensed liquid thermos-physical properties are taken for the reference temperature between the saturation temperature and wall temperature, calculated according to the following equation:

$$t_{ref} = t_h - \frac{3}{8} \cdot (t_h - t_{wall}) = 80.12 - \frac{3}{8} \cdot (80.12 - 75.63) = 78.43°C$$

For the first calculation of heat transfer surface and heat transfer coefficient the wall temperature assumed to be 78 °C. After several iterations the wall temperature was accurately defined to value 75.63°C.[49]

Prandtl number of condensed liquid:

$$\Pr_h = f(p_h; t_{ref}) = f(0.4764 bar; 78.43°C) = 2.276$$

Dynamic viscosity of condensed liquid:

$$\mu_h = f(p_h; t_{ref}) = f(0.4764 bar; 78.43°C) = 361.4 \cdot 10^{-6} Pa \cdot s$$

Thermal conductivity of condensed liquid:

$$\lambda_h = f(p_h; t_{ref}) = f(0.4764 bar; 78.43°C) = 0.666 W/(m \cdot K)$$

Density of condensed liquid:

$$\rho_h = f(p_h; t_{ref}) = f(0.4764 bar; 78.43°C) = 972.75 kg/m^3$$

Density of saturated vapor:

$$\rho^{"} = f(p_h; t_{ref}) = f(0.4764 bar; 78.43°C) = 0.295 kg/m^3$$

Heat transfer coefficient of single horizontal tube during condensation is calculated by following equation:

$$\alpha_{hor} = 0.725 \cdot \sqrt[4]{\frac{\lambda_h{}^3 \cdot \rho_h \cdot \left(\rho_h - \rho''\right) \cdot g \cdot i_{h,fg}}{\mu_h \cdot \left(t_h - t_{wall}\right) \cdot d_2}}$$

$$\alpha_{hor} = 0.725 \cdot \sqrt[4]{\frac{0.666^3 \cdot 972.75 \cdot (972.75 - 0.295) \cdot 9.81 \cdot 2307.77}{361.4 \cdot 10^{-6} \cdot (80.12 - 75.63) \cdot 0.04}}$$

$$\alpha_{hor} = 12807.82 W/\left(m^2 \cdot K\right)$$

Heat transfer coefficient by Kern (as shown below) includes the effect of tube distribution in a shell & tube heat exchanger:

$$\alpha_h = \alpha_{hor} \cdot n_{total}{}^{-1/12} = 12807.82 \cdot 734^{-1/12} = 7829.84 W/\left(m^2 \cdot K\right)$$

7.2.4. Overall heat transfer coefficient

$$U = \frac{1}{\frac{d_2}{\alpha_c \cdot d_1} + \frac{1}{\alpha_h} + \frac{d_2}{2 \cdot \lambda} \cdot \ln\left(\frac{d_2}{d_1}\right)}$$

$$U = \frac{1}{\frac{0.04}{4731.91 \cdot 0.036} + \frac{1}{7829.84} + \frac{0.04}{2 \cdot 120} \cdot \ln\left(\frac{0.04}{0.036}\right)}$$

$$U = 2630.96 W/\left(m^2 \cdot K\right)$$

During the condensation of pure vapour in shell & tube heat exchanger, the situation may be as sketched in Figure 15. The cold-water increases in temperature more rapidly in the first pass than in the second pass due to the decreased temperature difference. If we assume constant overall heat transfer coefficient, then the logarithmic mean temperature difference is given by following equation. [48]

$$LMTD = \frac{t_{c,out} - t_{c,in}}{\ln\left[\frac{(t_h - t_{c,in})}{(t_h - t_{c,out})}\right]} = \frac{75.12 - 52.06}{\ln\left[\frac{(80.12 - 52.06)}{(80.12 - 75.12)}\right]} = 13.365K$$

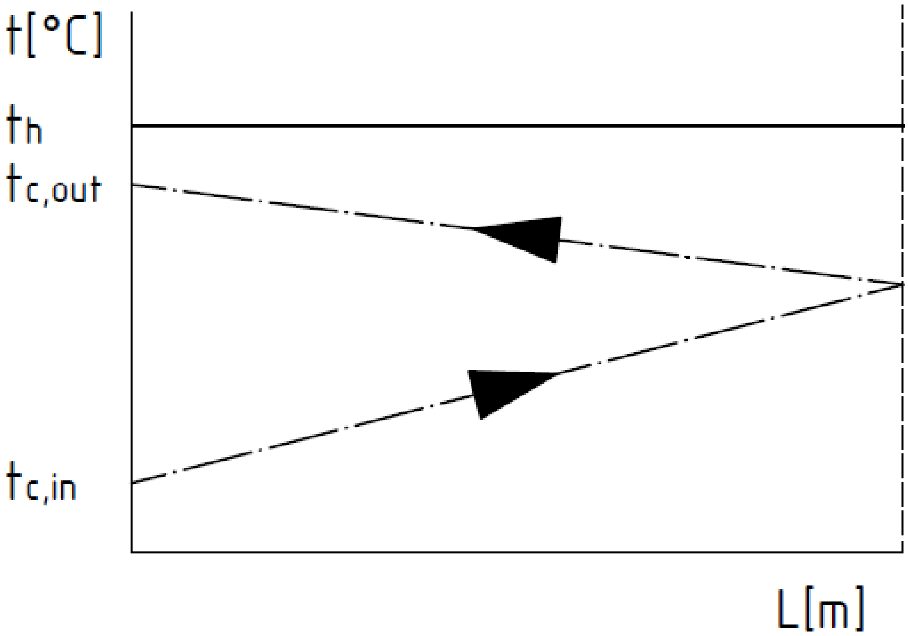

Figure 17 - Water temperature during movement in feed water heater

Heat transfer area calculation:

$$A = \frac{\dot{Q}}{U \cdot LMTD} = \frac{30857.54 \cdot 10^3}{2630.96 \cdot 13.365} = 877.55m^2$$

Total tube length at each pass:

$$L = \frac{A}{\pi \cdot d_2 \cdot n_{total}} = \frac{877.55}{\pi \cdot 0.04 \cdot 734} = 9.514m$$

Wall temperature at vapor side:

$$\dot{Q} = A \cdot \alpha_h \cdot (t_h - t_{wall})$$

$$\Rightarrow t_{wall} = t_h - \frac{\dot{Q}}{A \cdot \alpha_h} = 80.12 - \frac{30857.54 \cdot 10^3}{877.55 \cdot 7829.84} = 75.63°C$$

7.2.5. Throat parameters

Water throat diameter:

$$D_c = \sqrt{\frac{4 \cdot A_{c,real}}{\pi}} = \sqrt{\frac{4 \cdot 0.374}{\pi}} = 0.69m \rightarrow DN700$$

Inlet throat is positioned at the top of the shell, where recommended saturated vapor velocity is in the range from 10 m/s to 30 m/s. Due to the low pressure of inlet vapor two inlet throat design is used.

Saturated vapor velocity:

$$w_{h,in} = 30m/s$$

Vapor inlet throat area:

$$A_{h,in} = \frac{\dot{m}_h}{w_{h,in} \cdot \rho''} = \frac{13.37}{30 \cdot 0.295} = 1.51m^2$$

Diameter of inlet vapor throat:

$$D_{h,in} = \sqrt{\frac{4 \cdot \frac{A_{h,in}}{2}}{\pi}} = \sqrt{\frac{4 \cdot \frac{1.51}{2}}{\pi}} = 2x0.98m \rightarrow 2xDN1000$$

Real vapor inlet throat area:

$$A_{h,real} = 2 \cdot \frac{\pi \cdot D_{h,in}{}^{2}}{4} = 2 \cdot \frac{\pi \cdot 1^{2}}{4} = 1.57m^{2}$$

Real saturated vapor velocity:

$$w_{h,real} = \frac{\dot{m}_h}{\rho^{"} \cdot A_{h,real}} = \frac{13.37}{0.295 \cdot 1.57} = 28.86m/s$$

Outlet condensate velocity in the throat:

$$w_{h,out} = 0.8m/s$$

Condensate outlet throat area:

$$A_{con} = \frac{\dot{m}_h}{w_{h,out} \cdot \rho_h} = \frac{13.37}{0.8 \cdot 971.71} = 0.017m^{2}$$

Throat diameter of condensate:

$$D_{h,in} = \sqrt{\frac{4 \cdot A_{con}}{\pi}} = \sqrt{\frac{4 \cdot 0.017}{\pi}} = 0.148m \rightarrow DN150$$

Drawing documentation of selected heat exchanger is in Attachment 6.

8. Conclusion

The objective of this thesis was to evaluate the possibility of integration post-combustion CCS technology using ammonia scrubbing to supercritical 660 MWe power plant in condition of Czech Republic. And also estimate cost of the electricity, technical and economic impact of the CO_2 capture integration into existing power plant Ledvice. I did recherché of the post-combustion CCS technology to find all the information I will need to design this capture unite as well as other technologies which could be used for the reference power plant. At the end of the recherché, I compared all the CCS technologies, all the method for CO_2 separation with selected method. For integration of the post-combustion technology for steam cycle power plant there are several design possibilities which the affect layout of the power plant, cost of the electricity and performance. As preferred technology for reduction of the emission of CO_2 for this thesis was chosen ammonia scrubbing. The possibility of different solvent was also discussed but in condition of Czech Republic is selected option with ammonia closest to real use. The design I have chosen is also preferable design and most of the research papers is focused for this solution of the reduction of CO_2 capture.

At first, I had to designed model of the steam cycle power plant without CCS. This model was designed according to Ledvice power plant and it served as referenced power plant. I designed the first model in Cycle-Tempo Release 5.0. After the model corresponds to the real power plant, I used this model to design similar power plant with gPROMS software platform (gCCS). I chose gCCS because it offered for extension first reference model wider possibilities flue gas cleaning technologies. As the final design of the reference power plant, I selected electro static precipitator and flue gas desulphurisation unit as the typical representative. Thanks for post-combustion and known fuel from open-pit Ledvice the flue gas contain the high amount of the ash and sulphur, so the flue gas equipment has a big role and it cannot be omitted. Final net efficiency after including of flue gas treatment is 42.78 %. The big advantage of ammonia as a solvent in separation unit is then another desulphurisation unit is no needed.

The reference steam cycle power plant with CCS was designed as an extended of existing power plant. I must reduce the gross power output and net efficiency due to bigger consumption of stem. By this approach both fuel consumption should be comparable. The impact of CCS technology was quantified as a decrease of gross power output to 624 MW. The gross efficiency is 43.69 % due to lower mass flow in the cycle. The net efficiency difference is even lower, only 36.84% (1.1 GJ/t_{CO2} – CO_2 capture specific energy requirement) that is 5.93 percentage points lower than in referenced power plant.

The cost of the electricity from the power plant with CCS is almost 32% more expensive than from the referenced power plant. This is cause by the lower efficiency and higher investment cost. It is mainly caused by huge energy consumption for solvent regeneration but and consumption of the compressors for CO_2 transportation. From the results of the economic analysis it is obvious that this solution is not suitable for large scale application in the Czech Republic. The cost of the electricity would rise which would have largely negative effect for the economy. For large scale application of the CCS technologies further research and development is essential. Especially research new ways of absorption and adsorption with emphasis on energy demand. This progress could me make more faster renewal of market with emission permits and increasing the competitiveness of renewable resources, otherwise, the CCS technology would cause the higher cost of energies and also faster depleting of the fossil fuels.

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10. List of attachments

Attachment 1: Complete list of solvents

Attachment 2: Basic scheme of Ledvice power plant [51]

Attachment 3: Scheme of reference power plan

Attachment 4: List of apparatus in scheme

Attachment 5: Print screen from gCCS

Attachment 6: Heat Exchanger drawing