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Effects of carbon capture on an existing combined cycle gas turbine power plant

Thesis submitted in partial fulfillment of the requirements for the degree of Master of Science in Technology

Espoo, August 19, 2011

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AALTO UNIVERSITY PO Box 11000, FI-00076 AALTO http://www.aalto.fi		ABSTRACT OF THE MASTER'S THESIS	
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<p>Abstract:</p> <p>Carbon capture and storage (CCS) is the only technology available for the reduction of greenhouse gas emissions from large-scale fossil fuel usage. The objective of this study is to give an overview of the potential for applying CCS in an existing natural gas combined cycle gas turbine power plant. Helsingin Energia's Vuosaari B power plant was used as an example.</p> <p>Different technically available post-combustion carbon capture technologies applicable to gas turbine power plants are introduced. The alternative that was discovered the best, in this case chemical absorption with monoethanolamine (MEA) as a solvent, was chosen for further investigation.</p> <p>The carbon capture and compression unit is integrated into the power plant in a way that involves minimum changes to the existing process. Heat energy required by the chemical reaction of the carbon capture process is recovered from low pressure steam from the power plant. Impacts in the process are demonstrated by creating a power plant model and simulating different modes of operation of the power plant with and without CCS.</p> <p>The cost assessment focuses on the impacts on revenues before and after CCS integration. Also the investment costs of the carbon capture and compression unit are estimated.</p> <p>The amount of sellable district heat and electrical power decrease due to energy demand of the carbon capture and compression unit. This also decreases revenues from district heat and electricity. These changes are presented in the results. Impacts on the overall efficiency are significant: depending on the mode of operation, it decreases 15-17 percent units. The impact was the greatest in heat power generation. At the same time, the revenues decrease notably. With a 90 % carbon separation rate, the overall global warming potential sinks by 64 %.</p>			
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<p>Tiivistelmä: Hiilidioksidin talteenotto ja varastointi on ainoa olemassa oleva tekniikka laajan mittakaavan kasvihuonekaasupäästövähennysten saavuttamiseksi fossiilisia polttoaineita käyttävillä voimalaitoksilla. Diplomityössä selvitetään hiilidioksidin talteenottomahdollisuuden lisäämisen vaikutuksia prosessiin olemassa olevalla voimalaitoksella. Esimerkkilaitoksena on Helsingin Energian maakaasukäyttöinen kombivoimalaitos Vuosaari B, jota käytetään sähkön ja kaukolämmön tuotantoon.</p> <p>Työn kirjallisuusosassa käydään läpi erilaisia tekniikoita hiilidioksidin talteenottoon savukaasuista. Näistä vaihtoehtoista valitaan parhaiten soveltuva tarkempaa tarkastelua varten. Tarkastelua varten valittu vaihtoehto on kemiallinen absorptio, jossa käytetään liuoksena monoetanoliamiinia (MEA).</p> <p>Hiilidioksidin talteenottolaitos pyritään integroimaan voimalaitokseen siten, että itse voimalaitokseen tehtävät muutokset pysyvät mahdollisimman vähäisinä. Hiilidioksidin talteenoton vaatima lämpöenergia saadaan voimalaitoksen matalapainehöyrystä. Vaikutukset voimalaitosprosessiin selvitettiin laatimalla olemassa olevasta voimalaitoksesta malli, ja simuloimalla sillä muutoksia eri ajotavoilla.</p> <p>Kustannustarkastelussa keskityttiin tarkastelemaan hiilidioksidin talteenoton aiheuttamia muutoksia nykytilanteeseen. Myös laitoksen investointikustannuksista esitetään karkea arvio.</p> <p>Hiilidioksidin talteenoton ja kompressoinnin vaatima lämpö- ja sähköteho vähentävät kaukolämmön ja sähkön määrää, ja myös niiden myynnistä saatavia tuloja. Näitä vaikutuksia esitellään työn tuloksissa. Muutoksien havaittiin olevan huomattavia: kokonaishyötysuhde laski ajotavasta riippuen 15-17 prosenttiyksikköä. Suurin muutos havaittiin laitoksen kaukolämpötehossa. Samalla myös myyntitulot laskevat huomattavasti. 90 % hiilidioksidin erotusasteella saavutetaan todellisuudessa noin 64 % lasku kasvihuonevaikutuksessa.</p>		
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Preface

First, I would like to thank my employer for giving me this opportunity to finalize my studies and to work in an interesting and educative environment for so many years.

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Nomenclature

BL	Battery Limit
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CO ₂ -EOR	Carbon Dioxide Enhanced Oil Recovery
DH	District Heat
EOR	Enhanced Oil Recovery
GHG	Green house gas
GT	Gas Turbine
HP	High-Pressure
HRSG	Heat Recovery Steam Generator
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate-Pressure
LP	Low-Pressure
MEA	Monoethanolamine
NG	Natural gas
PSA	Pressure swing adsorption
TSA	Temperature Swing Adsorption
VuB	Vuosaari B power plant

1 INTRODUCTION

1.1 BACKGROUND

Climate change is considered a major challenge. Secure, reliable and affordable energy supplies are necessary for economic growth, although the increase in the associated carbon dioxide emissions is a cause of concern. Approximately 69 % of all CO₂ emissions, and 60 % of all greenhouse gas (GHG) emissions, are energy-related. It is agreed that cutting down energy-related CO₂ emissions by 50 % by 2050 is needed in order to limit the expected temperature increase to less than 3 degrees. To achieve this goal, it will take an energy technology revolution that involves increased usage of renewable energies, increased energy efficiency, and the decarbonisation of power generation from fossil fuels. (IEA, 2008)

The only technology available to reduce greenhouse gas emissions from large-scale fossil fuel usage is carbon capture and storage (CCS). As shown in Figure 1, according to BLUE map scenario made by International Energy Agency (IEA), CCS will need to contribute to nearly one-fifth of the necessary emissions reductions to halve global GHG emissions by 2050 at a reasonable cost. Therefore, CCS is essential to the achievement of deep emission cuts. (IEA, 2008)

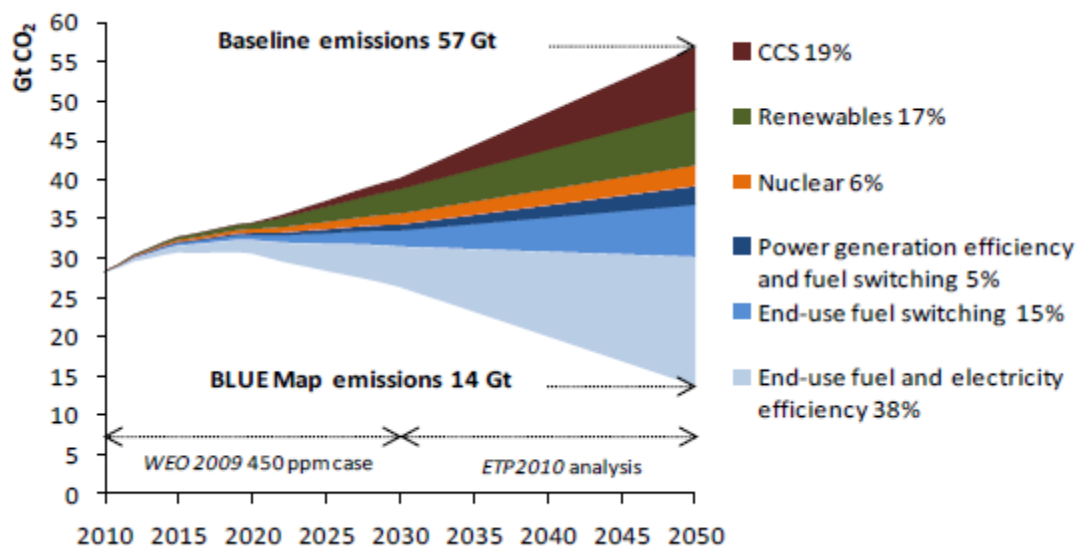


Figure 1. BLUE map scenario estimates that the contribution of CCS to global GHG emission reduction is 19 % by 2050. (IEA , 2010)

In Finland, decision making has been more focused on renewable and nuclear, and there is currently no clear policy for CCS. However, CCS is noticed as an important technology by 2050 with 80% emission reduction target. (Teir, et al., 2010)

CCS consists of three basic technologies: separation of carbon dioxide from gas stream, transportation of captured CO₂ and storage. In power generation, the capture of CO₂ is usually divided in three groups as presented in Figure 2: post-combustion capture, pre-combustion capture and oxyfueling (or denitrogenation).

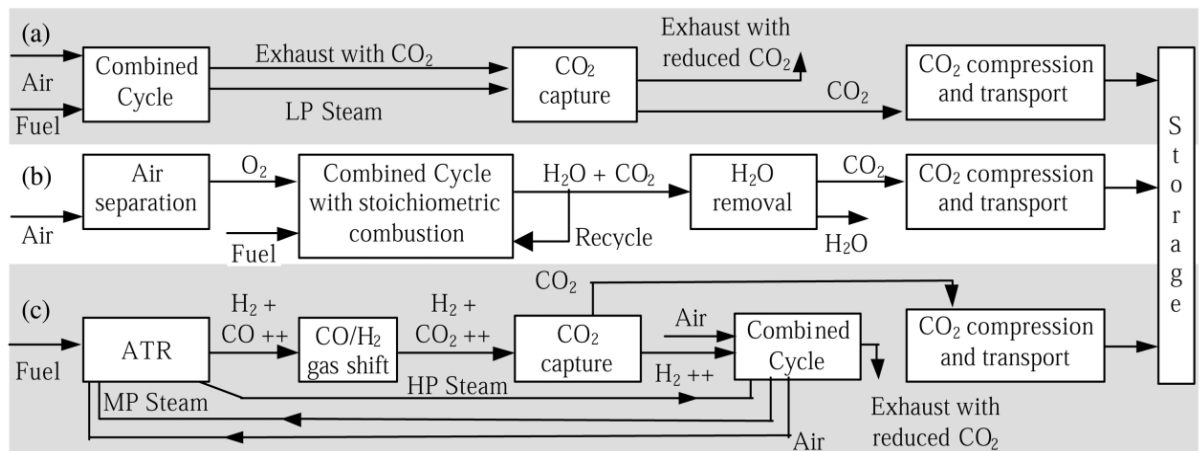


Figure 2. The three carbon capture concepts for natural gas fired power plants: (a) post-combustion capture, (b) oxyfueling and (c) pre-combustion capture. (Bolland & Undrum, 2002)

This master's thesis is made for Helsingin Energia as a part of a study made for CLEEN Oy (Cluster for Energy and Environment), Finnish energy and environment competence cluster, which is one of the SHOKs or Strategic Centres for Science, Technology and Innovation. The aim of the CCSP (Carbon Capture and Storage Programme) of CLEEN Oy is to find potential CCS solutions for natural gas-fired CHP power plants. Thus far, carbon capture from coal-fired power generation has received more attention. However, considerable decarbonisation of electricity generation may not be sufficient in many countries without the deployment of CCS on natural gas combined cycle gas turbine plant as well.

1.2 OBJECTIVES

The objective of this study is to give an overview of the potential for applying CCS in a natural gas combined cycle gas turbine power plant. Different technically available

post-combustion carbon capture technologies applicable to gas turbine power plants are introduced. This study focuses on post-combustion technologies; pre-combustion and oxyfuel technologies are left out of the review. The solution identified the most potential is chosen for more detailed assessment. Techno-economical evaluation consists of process modelling and case study. The case study is based on retrofitting post-combustion carbon capture unit for an existing power plant, Vuosaari B combined cycle gas turbine (CCGT) power plant. This study has special emphasis heat flow integration between a carbon capture unit and a combined heat and power (CHP) generation plant. After simulations, it is possible to compare power plant process and profitability before and after CCS retrofit. In CHP carbon capture applications the overall energy penalty caused by CCS is likely to be lower compared to condensing power plant CCS applications because there is a possibility to recover waste heat from the capture unit for district heat (DH). In this study, the aim was to carry out the CCS retrofit with as few alterations to the original CCGT process as possible.

1.3 VUOSAARI B

The power plant of the case study is modelled according to an existing combined cycle gas turbine power plant, Vuosaari B. The Vuosaari B (VuB) power plant, located in Vuosaari in Helsinki, is owned and operated by Helsingin Energia. Vuosaari B power plant, together with Vuosaari A, generates most of the district heat and electricity sold by Helsingin Energia. Both plants were built in the 1990's. Vuosaari B is a combined cycle gas turbine power plant that generates both electricity and district heat. It uses natural gas as a fuel. Its generation output is 470 MW of electricity and 420 MW of district heat. Vuosaari B uses 500-600 million m³ of natural gas every year. It is considered to be among the most efficient and cleanest plants in the world, due to its advanced generation technology. (Helsingin Energia, 2002)

VuB has two gas turbines (GT 4 and 5) and two heat recovery steam generators (HRSG 4 and 5). The HRSG generates high-pressure and low-pressure steam. The generated steam is fed to a steam turbine utilizing three pressure stages. The steam turbine generates electricity via a generator and after turbine steam is fed into two heat exchangers for district heat generation. District heat is also generated in the cold-end of the HRSG, which enables the maximum utilization of the heat in the flue gases. Electricity is also generated by the generators of the two gas turbines. The efficiency of

the gas turbines is approximately 33 to 34 %. With the steam turbine electrical efficiency raises up to 51-52 %. The overall efficiency is 91-92 %. The nitrous oxide emissions are minimized by LOW-NO_x burning technique in the burning chambers of the gas turbines. (Energia, 1997)

The closest inhabitants live over one kilometre away from the power plant. When designing the power plant, the aim was to minimize noise levels around the power plant area. During plant operation, the maximum allowed noise level outside the power plant area is 45 dB. (Energia, 1997)

2 POST-COMBUSTION CCS TECHNOLOGIES

In post-combustion capture, carbon dioxide is removed from the flue gases before they are released into atmosphere. For CO₂ capture from combined cycle gas turbine power plants, it would also be possible to use pre-combustion capture. This means that hydrogen is produced from natural gas reforming. However, the relative costs for pre-combustion capture are estimated to be higher in comparison with post-combustion capture with natural gas as a fuel. (Gibbins, 2009)

Figure 3 presents different post-combustion CO₂ separation and capture technologies that are technically available or under development. More information about the technologies can be found in the following chapter.

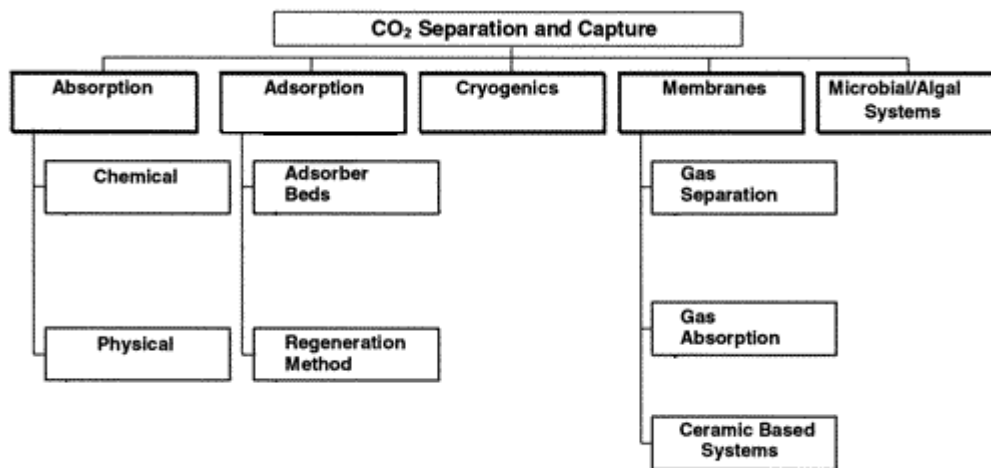


Figure 3. Process technologies for post-combustion CO₂ separation and capture. (Rao & Rubin, 2002)

2.1 CHEMICAL ABSORPTION

At present, chemical absorption is considered the most viable technology option for CO₂ post-combustion capture. Chemical absorption is a commercially realized technology though in a scale not large enough required for power plants. This technology has been in use since the 1980's, for instance, in ammonia plants and food industry. CO₂ is separated from the flue gas in a continuous scrubbing system. The scrubbing system consists of an absorber and a desorber. Absorption processes utilize the reversible chemical reaction of CO₂ with an aqueous alkaline solvent. (Kothandaraman, Nord, Bolland, Herzog, & McRae, 2009)

2.1.1 Amine-based chemical absorption

A standard configuration of chemical absorption is shown in Figure 4. Flue gas enters the carbon capture process at close to atmospheric pressure. It is cooled to 40-60 °C, which usually is the required operating temperature. Cooling with direct water contact is considered beneficial because the water stream will also remove fine particulate matter from flue gas stream. Cooled flue gas is brought into contact with the lean solvent in a packed absorption tower or amine scrubber. CO₂ is separated from the flue gas stream to the solvent by a chemical reaction. Before exiting the top of the absorber, flue gas is washed with water. This decreases the entrainment of solvent droplets and vapour. After washing, the CO₂-free flue gas is then emitted into the atmosphere. (Rackley, 2010)

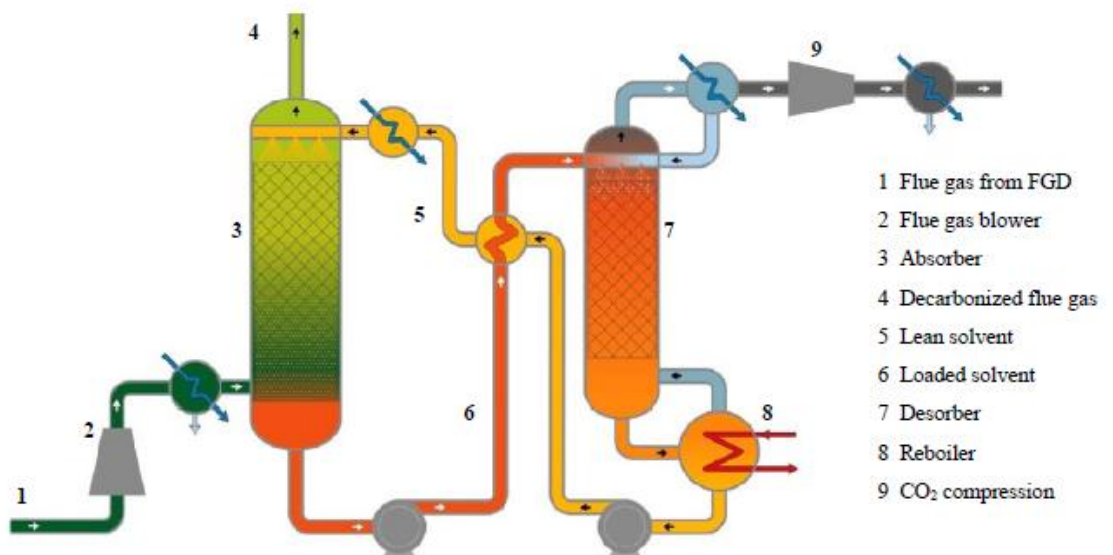


Figure 4. A standard process configuration for carbon dioxide capture by chemical absorption. (Jockenhoevel, Schneider, & Rode, 2009)

Rich solvent, which now has high reaction product content, exits at the base of the scrubber and is pumped to the top of the amine stripping tower (desorber). The rich solvent is heated by a heat exchanger that recovers heat from the regenerated solvent cycling back to the absorber. Typically, the stripping tower operates at 100-140 °C and at somewhat higher pressure than the absorber. The required heat is generated by the host plant or by a reboiler. In the stripping tower, the absorption reaction is reversed to

release pure CO₂ and to regenerate the lean solvent. Steam and CO₂ exit the top of the stripping tower; there the steam is condensed from the CO₂ stream. The lean solvent from the base of the tower is cycled back to the absorber after cooling. (Rackley, 2010)

For post-combustion capture, the ideal chemical solvent has high reactivity with respect to CO₂. This would reduce the height requirements for the absorber tower and reduce solvent circulation flow rates. It should also have low regeneration costs, based on the low heat of reaction with CO₂. (Wang, Lawal, Stephenson, Sidders, & Ramshaw, 2010)

2.1.2 Amine-based solvents

Amines have been utilized for the treatment of industrial gas streams for around 75 years. The most popular group of solvents is alkanolamines. Based on the degree of substitution of the nitrogen atom, amines can be classified as primary, secondary and tertiary. Primary and secondary alkanolamines form carbamates in a rapid reaction with CO₂. (Rackley, 2010)

For CO₂ capture, the most commonly used amine is ethanolamine, or monoethanolamine (MEA), a primary amine with the organic group R=CH₂CH₂OH. In an aqueous solution MEA acts as a weak base, which can neutralize an acidic molecule, such as carbon dioxide. A weakly bonded compound called carbamate is formed in this reaction:



In the reaction, the heat of absorption for CO₂ in MEA is 2.0 MJ/kgCO₂. (Rackley, 2010)

The nitrogen-carbon bond of the carbamate ion can be easily broken down by heating. This leads to the reverse reaction that regenerates the original solvent and releases carbon dioxide. For MEA regeneration:



(Rackley, 2010)

MEA is industrially the most important amine-based solvent. Compared with other solvents, the advantages of MEA are its high reaction rate and the ability to remove even traces of CO₂. In an ideal MEA absorption system, the solvent would be recycled

and reused continuously. However, MEA has a quite high vapour pressure, which causes considerable vaporization and solvent loss. Therefore, solvent has to be added to the process during operation. (Veltman, Singh, & Hertwich, 2010)

Only a few studies have been carried out concerning the impacts of MEA-related emissions in human health and environment, though it is widely recognized that these impacts are extremely important to assess. The lack of studies is primarily due to an absence of quantitative information on the emissions of MEA and degradation products. Besides, there are no human toxicity characterization factors for MEA. (Veltman, Singh, & Hertwich, 2010)

2.1.3 Ammonia-based chemical absorption

The ammonia-based chemical absorption system utilizes a typical absorber tower configuration, working at near-freezing conditions (0-10 °C). In the absorber tower, cooled flue gas flows up in counter current to the absorbent slurry. The chilled slurry consists of dissolved and suspended ammonium carbonate and ammonium bicarbonate in ammonia. The low operating temperature enables higher CO₂ loading of the solvent slurry and it also reduces ammonia slip. Ammonia slip can be further reduced by washing the flue gas with cold water. (Rackley, 2010)

The solvent slurry regenerator operates at temperatures higher than 120 °C and pressures higher than 2 MPa. In regeneration, ammonia slip is controlled by washing with water. This regeneration with high pressure has the benefit of lowering the energy requirement for later compression and delivery of the CO₂ product stream to storage. (Rackley, 2010)

This process is being developed and it is considered promising. The process is the subject of an extensive development program which includes testing on a pilot power plant. (Rackley, 2010)

2.2 PHYSICAL ABSORPTION

Carbon capture using physical absorption is based on the solubility of CO₂ in the solvent. The solubility depends on the CO₂ partial pressure and temperature on the flue gas. Physical absorption has an advantage over chemical absorption: the heat requirement for desorption is substantially lower. (Rackley, 2010)

For regeneration, heat, pressure reduction or both can be used. Nonetheless, to achieve adequate solvent loading, this also calls for low operating temperatures at the absorption stage. For physical solvents, the solvent loading capacity increases with the partial pressure of the sorbate. Therefore, physical absorption is commonly utilized for CO₂ separation at high pressure, for instance, CO₂ recovery from a produced natural gas stream. For low-pressure applications, such as CO₂ capture from flue gas, chemical absorption is a more preferred option. Utilization of physical absorption for CO₂ capture from flue gas would necessitate the compression of large volumes of gas, consisting mainly of nitrogen, which would subsequently be blown down for release into the atmosphere. The resulting energy penalty would make the process uneconomical. (Rackley, 2010)

2.3 ADSORPTION

CO₂ separation with adsorption is considered to become a viable alternative to high energy-demanding amine scrubbing technologies in the near future. In recent years, significant advances have been achieved towards the development of an adsorption-based CO₂ capture technology. (Sayari, Belmabkhout, & Serna-Guerrero, 2011)

Adsorption is a physical process involving the attachment of a liquid or a gas to a solid surface. The applications for solvent regeneration utilize heat (Temperature Swing Adsorption, TSA) or the reduction of pressure (Pressure Swing Adsorption, PSA). Adsorbents which could be used for CO₂ capture include activated carbon, metallic oxides, alumina and zeolites. Existing adsorption systems may not be adequate for large-scale power plant flue gas treatment. At a larger scale, significant challenges arise from the low adsorption capacity of most available adsorbents. Moreover, the flue gas streams must have high CO₂ concentrations since most available sorbents generally

have low selectivity. For example, zeolites have stronger affinity for water vapour. (Wang, Lawal, Stephenson, Sidders, & Ramshaw, 2010)

Unlike in absorption, in which the absorbed component (the sorbate) forms a solution with the solvent, adsorbed molecules remain on the sorbent's surface. The bonding of the adsorbate to the surface may be through either a chemical bond or a physical attractive force, similar to absorption. The history of industrial application of gas separation or purification based on adsorption is as long as that for absorption-based technologies. Adsorption processes using solid sorbents have some potential advantages in comparison to absorption into liquid sorbents. These advantages include a wide range of operating temperatures, lack of liquid waste streams, and solid wastes that in many cases are environmentally benign and pose fewer problems of disposal. (Rackley, 2010)

2.4 MEMBRANES

When utilized in gas absorption, membranes work as contacting devices between the flue gas stream and the liquid solvent. In some systems, the membrane provides additional selectivity. Membranes offer some advantages over the conventional contacting devices because they are more compact and not prone to flooding, entrainment, channelling and foaming. However, to enable CO₂ transport across the membrane, the pressures on the liquid and gas sides have to be equal. As their separation efficiency depends on the CO₂ partial pressure, they are more suitable for high CO₂-concentration applications such as flue gas streams from oxyfuel and integrated gasification combined cycle (IGCC) processes than for CCGT processes. (Wang, Lawal, Stephenson, Sidders, & Ramshaw, 2010)

In membrane-based separation, selectivity is enabled by the membranes themselves. Nonetheless, the selectivity of this separation process is low and consequently only a fraction of the CO₂ is captured. For the same reason, the purity of the captured CO₂ is low. (Wang, Lawal, Stephenson, Sidders, & Ramshaw, 2010)

Membranes have potential applications in carbon capture from post-combustion flue gases. In gas separation, membrane act as a filter which separates a specific component (permeate), from a mixture of gases in a feed gas stream. A number of different chemical and physical processes can be involved in this filtration process, depending on

the membrane materials and design. The separation of CO₂ from flue gases with the membrane is an active field of research. The aim is to enable large-scale demonstration and deployment by reducing the energy penalty and cost of membranes. The characteristics that need to be achieved before membrane becomes a commercial option for CO₂ separation from high-volume flue gases are:

- Low space requirements and capital cost
- Low sorption capacity for nonselected gases, such as N₂, CH₄, H₂
- Resistance to contaminants (SO_x, NO_x, H₂O, H₂S)
- Thermal stability at operating temperature
- Sufficient permeate flux for desired operating throughput

At present, demonstration systems need a large membrane area and multiple separation stages in order to achieve both high flow rate and permeate purity. (Rackley, 2010)

2.5 OTHER OPTIONS

2.5.1 *Cryogenic and distillation systems*

Distillation techniques are suitable for CCS in two areas: production of oxygen by cryogenic air separation for oxyfuel combustion, and CO₂ separation from natural gas for reinjection in an enhanced oil recovery (EOR) project or to treat gas to meet sales specifications. (Rackley, 2010)

In cryogenic separation, CO₂ is separated from the flue gas stream by condensation. CO₂ condenses at -56.6 °C at atmospheric pressure. Considering the costs of refrigeration, this process is suitable for treating flue gas streams with high CO₂ concentrations. Cryogenic separation is mainly used for carbon capture for oxyfuel process. (Wang, Lawal, Stephenson, Sidders, & Ramshaw, 2010)

2.5.2 *Mineral carbonation*

Methods based on the process of mineral carbonation aim at storing carbon dioxide in the form of products chemically stable and relatively safe. The process is similar to the slow, natural processes of the weathering of igneous rocks and storing into long-term carbon sinks. Mineral carbonation is a technology that accelerates the natural process. The process involves the reaction of oxides or silicates of magnesium, calcium and iron

with carbon dioxide to form carbonates that are stable. At present, the technology is at the development stage. A wide range of applied research studies is being conducted, with focus on increasing the carbonation reaction rate. (Rackley, 2010)

2.5.3 *Industrial use*

Carbon dioxide is used in a wide range of industrial processes, such as the carbonation of soft drinks or the production of fertilizers. Nevertheless, only a few applications truly reduce CO₂ emissions since most products have a very short lifetime before CO₂ is released back into the atmosphere. Of those methods that actually reduce CO₂ emissions, not many have the potential to grow to a scale that would affect global emissions. (Rackley, 2010)

The use of CO₂ as feedstock for algal bio fuel production has potential to grow to an important global scale. Though it is not exactly a CCS option, because the combustion of the bio fuel will release the CO₂ back into the atmosphere (if not captured!), fossil fuels can be substituted by bio fuel in this way. In the short term, this can reduce the emission of fossil fuel CO₂ into the atmosphere. (Rackley, 2010)

Two possible industrial use options are the production of precipitated calcium carbonate by the carbonation of different alkaline wastes and the enhanced use of CO₂ in the cement industry. (Rackley, 2010)

2.6 CHOOSING CARBON CAPTURE TECHNOLOGY

The selection of a suitable process and solvent type is critical for the performance of the whole plant. The concentration of sulphur in the flue gas feed is very low for natural gas fired plant, so the washing process will not face the presence of SO_x in the flue gas. In these plants, only carbon dioxide will be captured. Several different solvent washing processes are commercially available for the post-combustion of the CO₂. (Foster Wheeler, 2010)

Although there are a number of theoretical licensors that could provide chemical-based solvents, in practice there are only very few that can offer a technology that is reliable for these applications in a scale large enough for power plants. For different technologies, two main problems are that these solvents should be proven for use in

oxygen containing flue gas streams, as well as there still are no commercial applications that require a large scale-up due to the large volumetric flows, as for the gas turbine based plants. (Foster Wheeler, 2010)

In terms of process configuration and operating principles for MEA solvent-based processes, all the commercially available technologies are more or less the same. (Foster Wheeler, 2010)

In this case, chemical solvents are the only option considered for carbon capture. This is mainly due to the low pressure of the flue gases in CCGT process, which results in a low partial pressure of CO₂. Low partial pressure makes the use of physical or hybrid solvents not economically feasible. Any chemical amine or ammonia or amino-acid based solvent can be used in post-combustion application. Amongst the amine-based solvents, MEA and the sterically hindered amines have already been utilized for the removal of acid gases, such as CO₂ and H₂S, in different commercial applications. On the other hand, ammonia and amino-acid processes are not as developed, but their performances are considered promising. (Foster Wheeler, 2010)

MEA was picked for solvent thanks to its high reaction rate and ability remove even traces of CO₂ efficiently.

There are also other criteria that should be paid attention to when choosing technology for carbon capture:

- Health and safety
- Operation flexibility
- Risk of underperformance
- Diversity of equipment and technology suppliers supplier
- Compatibility with operating experience of the utility
- Potential for future improvements

(Davidson, 2007)

3 CCS RETROFIT

For a retrofit project to be realisable, it must satisfy requirements in three areas that are shown in Figure 5. First, the power plant area needs to have enough space to be able to add a carbon capture unit. Secondly, there must be access to a secure CO₂ storage site. Finally, the retrofit should be economically and socially viable. This also includes meeting all legal requirements and gaining public acceptance. (Gibbins, et al., 2011)



Figure 5. The "Retrofit triangle" shows the three separate, though interlinked, requirements that need to be satisfied in order to a retrofit project to be viable. (Gibbins, et al., 2011)

3.1 SPACE REQUIREMENT

When evaluating the feasibility of making the retrofit of existing units, the first thing to be considered is if enough space is available for the installation of carbon capture and compression equipment. (Foster Wheeler, 2010)

The UK government has made a note giving some indicative figures for the carbon capture plant land footprint, which is based on an IEA report written in 2005. According to the guidance note, approximate minimum land footprint for a combined cycle gas turbine power plant with post-combustion capture with a net plant capacity of around 500 MW_e is 250 m x 150 m, 37500 m². In appendix A is a map of Vuosaari power plant area demonstrating the estimated space requirement. (Wearmouth, 2010)

Currently, there would be enough space in the power plant area for constructing a carbon capture and compression unit. Still, the space in the power plant area is limited. If a capture unit is built, it might make other development projects more difficult.

3.2 STEAM CYCLE INTEGRATION

The other important aspect that must be considered when retrofitting a power plant is a good integration of steam cycle with the capture plant. This is due to the fact that the solvent regeneration process requires a considerable amount of energy, so a proper integration is necessary to minimize the efficiency penalty of the plant. (Foster Wheeler, 2010)

The existing steam cycles have not been designed for a CCS retrofit and therefore do not necessarily possess the optimal steam conditions for steam extraction for solvent regeneration. The expected changes in power generation and the today's immaturity of post-combustion carbon capture technologies make successful thermodynamic integration with the power cycle challenging to achieve. Figure 6 presents one option for CCS retrofit integration. (Lucquiaud & Gibbins, 2011)

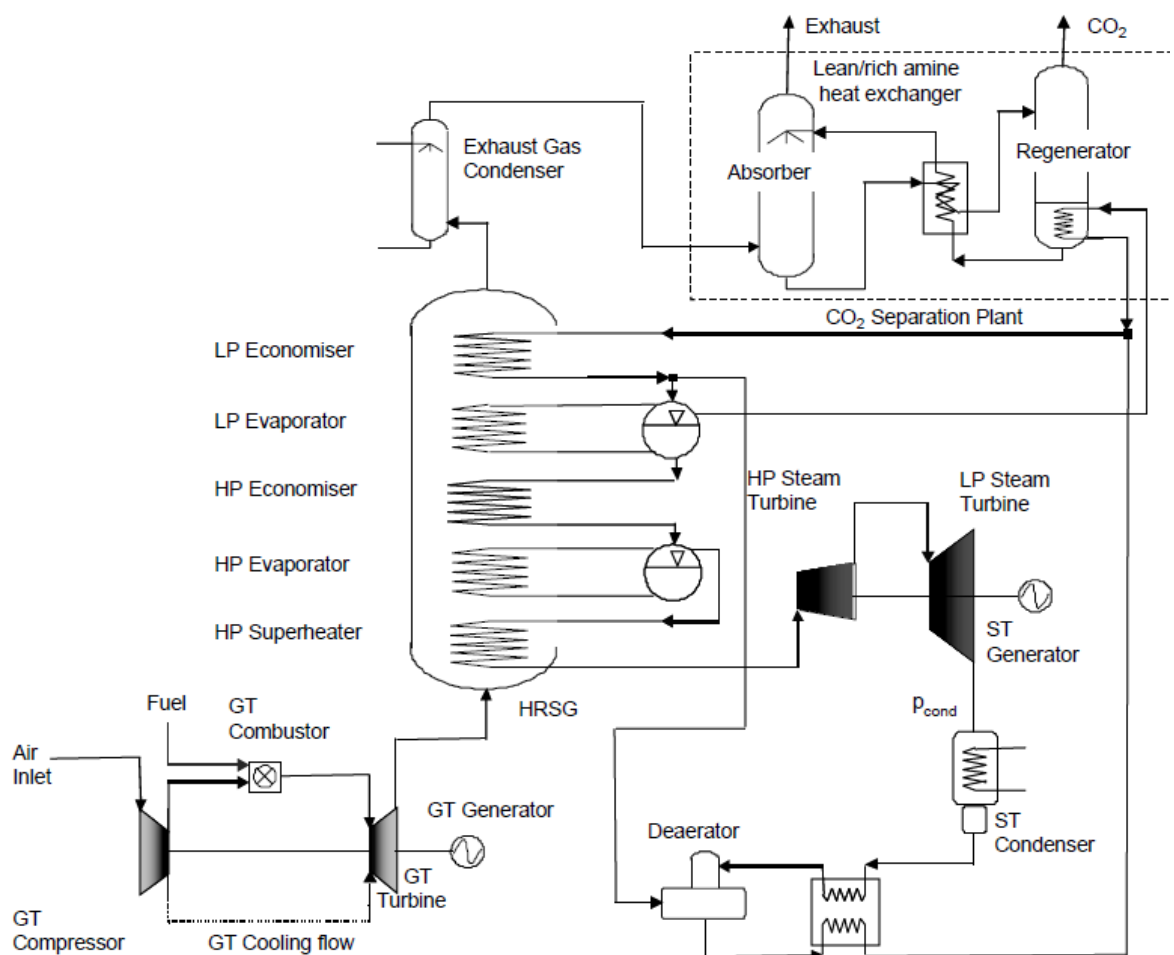


Figure 6. An example of carbon capture unit integration to a condensing CCGT power plant. LP steam utilized for solvent regeneration. (Möller, Assadi, & Potts, 2006)

Approximately 50 % of the fuel or energy penalty of the capture process arises because of the heat requirements of the solvent regeneration. It is recommended to supply the heat by condensing steam. This allows heating at a single temperature and removes the risk of damaging the solvent by overheating it. Roughly estimated the other half of the energy penalty is required to compress the captured CO₂, from about 2 bar to 110 bar for pipeline transport. The CO₂ partial pressure is around 0.04 bar in the flue gases and is 2 bar when it leaves the solvent stripper column. This means, that some of the heat required for solvent regeneration can provide CO₂ thermal compression. In the stripper, the CO₂ pressure is limited by the allowed maximum temperature. In turn, the peak temperature is limited by the thermal stability of the solvent. (Gibbins, 2009)

When retrofitting carbon capture, it is possible to replace the existing LP steam turbine with a new LP turbine cylinder. For the new LP turbine, the steam flow can be designed exactly to match the flow required by the CO₂ capture system. This naturally involves additional capital costs compared with the standard retrofit, but it enables achieving a system which performance resembles a new-build CCGT power plant with post-combustion capture. Seeing that the LP turbine is sized only for capture operation, the options for future changes in the carbon capture unit as technologies develop are limited. The power plants are locked in solvents that have identical or lower regeneration pressure than the initial solvent. (Lucquiaud & Gibbins, 2011)

3.3 PREPARATION OF THE FLUE GAS

Before absorption, acid gases (NO_x, SO_x) must be removed from the flue gases. They form heat stable salts with solvent, thus affecting the performance of the system. SO₂ concentration should be less than 10 ppm. The likelihood of corrosion in equipment increases in the presence of oxygen. It can also affect the degradation of alkanolamines like MEA. For use with MEA, oxygen levels less than 1 ppm are recommended when no corrosion inhibitors are used. Particulate matter should be removed from flue gas. If not removed, they would cause foaming in the absorber and regenerator columns, which decreases their performance. Flue gas has to be cooled to 45-50 °C before entering the CO₂ absorber. This will enhance the absorption of CO₂ and, additionally, minimize solvent losses caused by evaporation. (Wang, Lawal, Stephenson, Sidders, & Ramshaw, 2010)

Flue gas impurities also react with MEA that can cause MEA degradation. Particularly for natural gas combined cycle power plants the reaction with O₂ is important, for gas turbines burn natural gas with a high rate of excess air to control combustion temperatures. Solvent degradation is a concern for several reasons: it results in a loss of scrubbing capacity and fresh amine must be continually added to the process. The formation of degradation products causes corrosion, as mentioned before. Degradation of MEA may increase the environmental impacts of the process, as volatile degradation products are emitted to air with flue gas exhaust. (Veltman, Singh, & Hertwich, 2010)

3.4 CCS AND COMBINED HEAT AND POWER GENERATION

Carbon capture is an energy intensive process; the capture unit requires especially heat and the compressor unit electricity for compression. The energy penalty can be 15 percentage units in a retrofitted condensing power plant and around 10 percentage units in new systems. In a CHP power plant, the impact of the CCS is different and the total impact is likely to be not as big as in a condensing power plant. The impact depends on the amount of electricity loss that can be restored in a form of heat. It is discovered that in a coal fired CHP plant heat power can be higher after CCS implementation, as electrical power sinks. Figure 7 presents a simplified overview of the main interfaces in a CCS retrofitted power plant. (Gode & Hagberg, 2008)

CCS applications for condensing coal-fired power plants have been the main focus on recent research and development. Combined heat and power applications may have some advantages to applying CCS although there would also be some drawbacks. The overall efficiency of a CHP plant with CCS is considered higher in comparison to a condensing power plant with CCS, since there are low quality heat streams available from auxiliary processes that can be used more efficiently. The energy systems total effect on CO₂ emissions should always be considered as a whole. For instance, if heavy fuel oil-fired boilers are used to compensate the lower efficiencies, the emissions of the entire system might not be reduced. (Teir, et al., 2010)

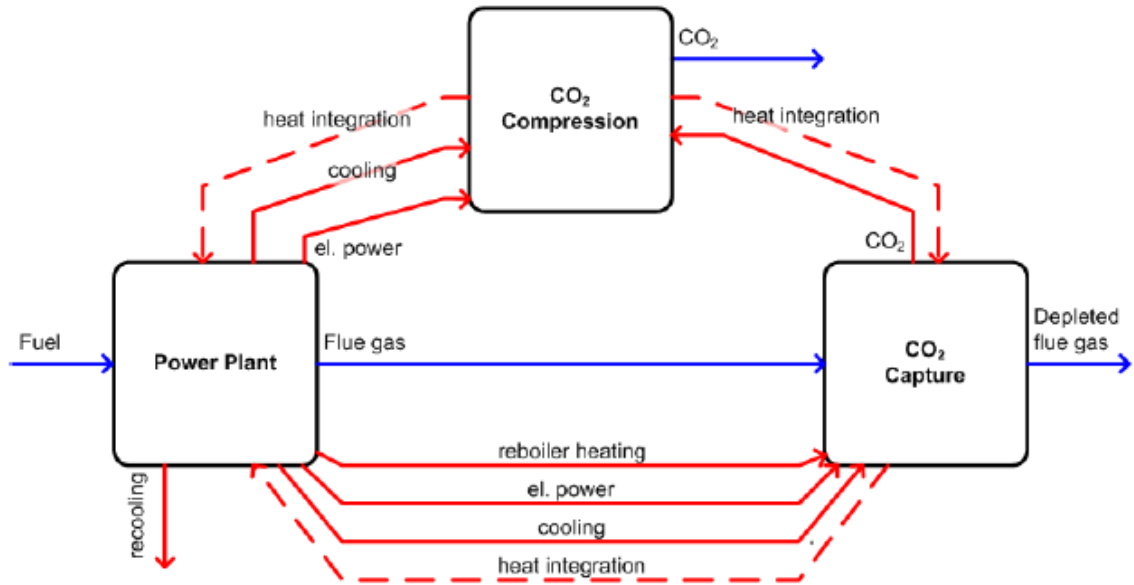


Figure 7. A simplified overview of the main interfaces within a power plant with carbon capture and compression units. (Jockenhoewel, Schneider, & Rode, 2009)

3.5 RETROFIT WITH A SEPARATE ANCILLARY BOILER

One option for steam cycle retrofit is a retrofit with a separate ancillary boiler and an optional back-pressure steam turbine. The addition of a separate natural gas ancillary boiler providing steam for solvent regeneration was originally proposed for coal plants, but it has been mostly disregarded in favour of steam extraction. A major drawback is its low efficiency. It has been noted that separate ancillary boilers do not exploit the full potential of the fuel calorific value. They turn the energy of the fuel to heat in low reboiler temperature compared with temperatures in the gas turbine, missing out the opportunity to extract higher-grade electrical energy. However, adding a separate boiler does not require modifications to the steam turbines and enable to avoid locking the plant in a specific solvent. (Lucquiaud & Gibbins, 2011)

If the boiler is used to generate superheated steam at a higher pressure, which is expanded in a back-pressure turbine, the plant is able to operate with the same net output to the grid both before and after the CCS retrofit. Still, the boiler and turbine do not use fuel with the same thermodynamic efficiency as combined cycle process. (Lucquiaud & Gibbins, 2011)

Because of the reasons mentioned above and because the objective of this study is to find possibilities for steam cycle integration, this option is left without further examination in this study.

3.6 POTENTIAL RISKS

3.6.1 *High oxygen concentration*

With the amine based solvents, the main concern is the high level of corrosion and degradation caused by the presence of oxygen and other impurities. This characteristic leads to the need for adding inhibitors in the solvent, to counteract the oxygen activity. Inhibitors also protect the equipment against corrosion and make possible the use of conventional materials of construction, such as carbon steel. Some licensors have already gained experience on solvent formulation with special inhibitors and specifically for natural gas fired flue gases. Therefore, the remaining risk related to high oxygen concentration can be considered medium low for these licensors. (Foster Wheeler, 2010)

3.6.2 *Scale-up*

The transfer of the currently used amine scrubbing process to the power industry, for CO₂ capture from flue gas, involves a significant scale-up issue. At present, there are no commercial CO₂ capture plants in operation in large power plants. The main risks refer to the size of the equipment, as well as the packing and the liquid distribution inside the absorber column. (Foster Wheeler, 2010)

However, the risk related to the scale-up issue can be considered medium. The equipment used in the process allows large scale-up, with no significant modifications. Licensors are able to provide absorbers with diameters that would correspond to a CO₂ recovery plant capacity up to 8000 t/day, depending on the inlet flue gas CO₂ concentration. Additionally, larger plants can be carried out by employing multiple absorbers that share a common stripper. For a large flue gas absorber, another possibility is a rectangular tower, which has already been utilized in some flue gas desulphurization plants. In comparison with the cylindrical towers, their construction on site is easier. In addition, the relevant equipment around the tower can be installed in

smaller area and the application of a large liquid distributor is simpler. (Foster Wheeler, 2010)

3.6.3 Flue gas impurities

The amine-based solvents react with any acid compounds to form amine salts. These amine salts are normally heat stable and do not dissociate on the amine stripping system. That is why it is necessary to achieve low levels of residual SO_x and NO₂ in the flue gas fed to the amine scrubbing. It should be noted that SO_x emissions for natural gas plants are related to the presence of sulphur in the fuel, which is almost negligible and therefore the level of SO_x in the flue gas is very low, approximately 1 ppmv. The concentration of NO₂ in the flue gas should not exceed 50 ppmv in 15 % O₂ volume dry. (Foster Wheeler, 2010)

According to measurements made in 2010, the NO_x concentrations in the flue gases of VuB are approximately 31 ppmv for gas turbine 4 and 29 ppmv for gas turbine 5, thus being below the recommended limit.

There are several concerns related to the unknown impacts of other types of impurities, such as metals and halogens. Nevertheless, they are typical of coal-fired power plants and not of natural gas power plants like Vuosaari B. (Foster Wheeler, 2010)

As a consequence of the considerations above, the risk related to the presence of impurities in the flue gas can be considered low for a natural gas power plant.

3.6.4 Environmental impacts

While CCS decreases the impact of global warming potential, CCS technologies increase other environmental impacts. These are: acidification, eutrophication and photochemical ozone creation. With carbon capture, the power plant produces MEA emissions and waste containing MEA, which should be treated as hazardous waste. (Modahl;Nyland;Raadal;Kårstad;Torp;& Hagemann, 2011)

When calculating other environmental impacts of CCS, the trade-offs are easily noticed. It has been estimated, that acidification caused by power plant operation increases by 43 %, eutrophication by 35 % and various toxic impacts by 120-170 %. (Singh, Stromman, & Hertwich, 2011)

The CCS process can represent a risk of worsening local air quality near the power plant area. Therefore, the developers of CCS at combustion sites are encouraged to consider the air quality impacts of the CCS modifications in an early stage of the project. In this way, mitigation strategies can be incorporated into the design in the most effective and environmentally beneficial way. (Ellis & Wolf, 2011)

4 CO₂ TRANSPORTATION AND STORAGE

4.1 CO₂ TRANSPORTATION

Suitable storage sites for CO₂ are rarely located near the source of CO₂. Consequently, captured CO₂ must be transported to the storage site. Within the region of Nordic Countries, distances from CO₂ sources to potential geological storage sites can be long, up to 1000-1500 km. Pipeline or ship transportation are the only viable options for an industrial scale. The CO₂ transportation chain is presented in Figure 8. (Teir, et al., 2010)

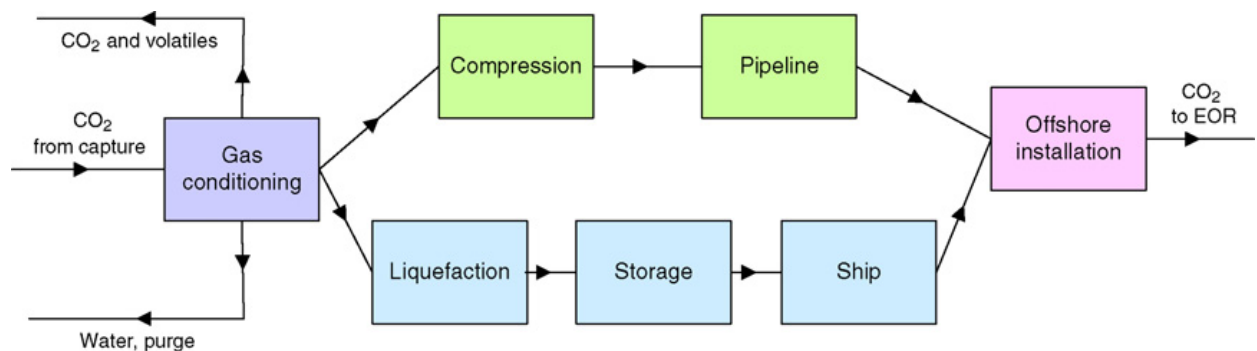


Figure 8. The CO₂ transport chain from carbon capture unit to enhanced oil recovery (EOR.). The chain remains unchanged when CO₂ is transported for geological storage. (Aspelund & Jordal, 2007)

4.1.1 Gas conditioning for CO₂ transportation

In the gas conditioning process, it is possible to treat CO₂ to near 100% purity. Nonetheless, in many cases it is more useful to have less strict specifications to reduce both capital and energy costs. At present, there are no fixed specifications for gas quality in CO₂ transport, and it is possible that in the future it will vary depending on the end target and on legislation in different areas. The main technical limitation will be the highest allowable impurity content in CO₂ to be injected or that can be allowed for pipeline or ship transport. The composition of CO₂ does not change during the transportation, provided that there are no leakages at any point of the CO₂ chain. Therefore, the CO₂ specifications need to be met by the carbon capture and conditioning process previous to transportation. (Aspelund & Jordal, 2007)

To ensure that no liquid enters the CO₂ compressors, vapour-liquid separator drums are needed. Separator drums using separation by gravity is the simplest as well as the most cost and energy effective way to remove components with higher density than gaseous CO₂. Water is principally an operational problem and has to be removed to avoid gas hydrates, the freezing of water and corrosion. Most of the water is usually removed in the first vapour-liquid separator drums before compression and cooling. After compression and cooling, most of the remaining water is condensed and is removed in the separator drum prior to the next compression stages. Finally after the separator drums the CO₂ gas can be dried by regenerative adsorption columns. H₂S and other contaminants are removed at this point. (Aspelund & Jordal, 2007)

Volatile gases, such as nitrogen or argon, rarely cause any safety or operational problems for pipeline transportation. In ship transport, most volatiles must be removed to avoid dry ice formation during liquefaction or transport. As transportation is both energy and cost intensive it is hardly reasonable to process and transport the volatiles. If not removed, 1 mol% of nitrogen increases the energy requirement of the transport chain with approximately 1%. (Aspelund & Jordal, 2007)

4.1.2 Pipeline transportation

CO₂ transportation by pipeline is quite simple and is considered a mature technology since it has been in use for enhanced oil recovery in the United States since the 1970's. The gas must be dehydrated before pipe transportation to prevent pipe corrosion caused by free water. For transportation, CO₂ is typically compressed to a pressure above 80 bar in order to avoid flow in two phases. Higher pressure also increases the density of CO₂, making transportation by pipeline easier and more cost-effective. The pipeline has to be designed accurately, especially the optimal pipeline size, to ensure reliable operation and low capital costs. Too small pipe diameters increase the flow velocity and cause pressure loss, and as a result, distances between pump stations along the pipeline are shorter. Additional pump stations mean higher capital costs, as well as operational costs, due to higher energy demand. On the other hand, pipelines with large diameters or thicker walls also cause high capital costs. (Teir, et al., 2010)

4.1.3 Ship transportation

CO₂ can alternatively be transported in a liquefied state by ships, road or trail. Ship transportation is considered the fastest and most flexible solution. Transportation by tankers requires intermediate storage for CO₂ with facilities for loading and unloading. CO₂ is liquefied to conditions close to the triple point, where CO₂ has the highest density. The liquefaction sets strict requirement for gas purity, for even small amounts of volatile gases such as nitrogen or argon may affect the formation of dry ice. Currently, the largest carriers for CO₂ shipping are in the range of 10 000 t/ship. (Teir, et al., 2010)

While CO₂ transport based on large-scale ships is a relatively new concept, liquefied hydrocarbon gas transportation in very large carriers is a significant contributor to global energy trade. Liquid natural gas (LNG) trade alone was 174 Mt in 2007. This proven technology and operating experience provide a basis for the development of marine options for CO₂ transportation. Today, large LNG carriers can reach 270 000 m³ and would be able to carry 0.3 Mt-CO₂ at the anticipated transport conditions for CO₂. (Rackley, 2010)

4.2 CO₂ STORAGE

At the end of the carbon capture chain the CO₂ is stored safely for a very long period of time. The amount of CO₂ that need to be stored is large. Thus, only a few storage options can be considered. Geological storage, the injection of CO₂ into permeable rock formations, is the only method of carbon storage that to date has been applied on a large enough scale. (Teir, et al., 2010)

4.2.1 Geological storage

Common for all geological storage methods of carbon dioxide is the super critical injection pressure (> 74 bar) of CO₂. In this pressure area, CO₂ acts as in steam phase but the density is as high as in liquid phase. CO₂ is injected to the porous space of the formation in a depth of over 800 meters where the rock bed above forms a pressure that matches with the pressure of injected CO₂. (Teir, et al., 2009)

Once the CO₂ is injected, a number of different physical and geological mechanisms prevent it from arising back to the surface. The most important one is the impermeable rock or clay layer over the CO₂ storage layer, since CO₂ is lighter than water and therefore tends to rise upward. Also the structure of the formation is an important factor when defining its suitability for storage. (Teir, et al., 2009)

Carbon dioxide displaces water. Once the injection is finished, water starts moving back to the formation trapping CO₂ with its pressure. In time, most of the injected CO₂ will dissolve to water forming a liquid which density is higher than the density of surrounding water. This liquid is expected to sink to the bottom of the storage formation. It is also possible that CO₂ reacts chemically with surrounding rocks and form stable minerals. However, mineralisation may take thousands of years. (Teir, et al., 2009)

Available options for geological storage are shown in Figure 9.

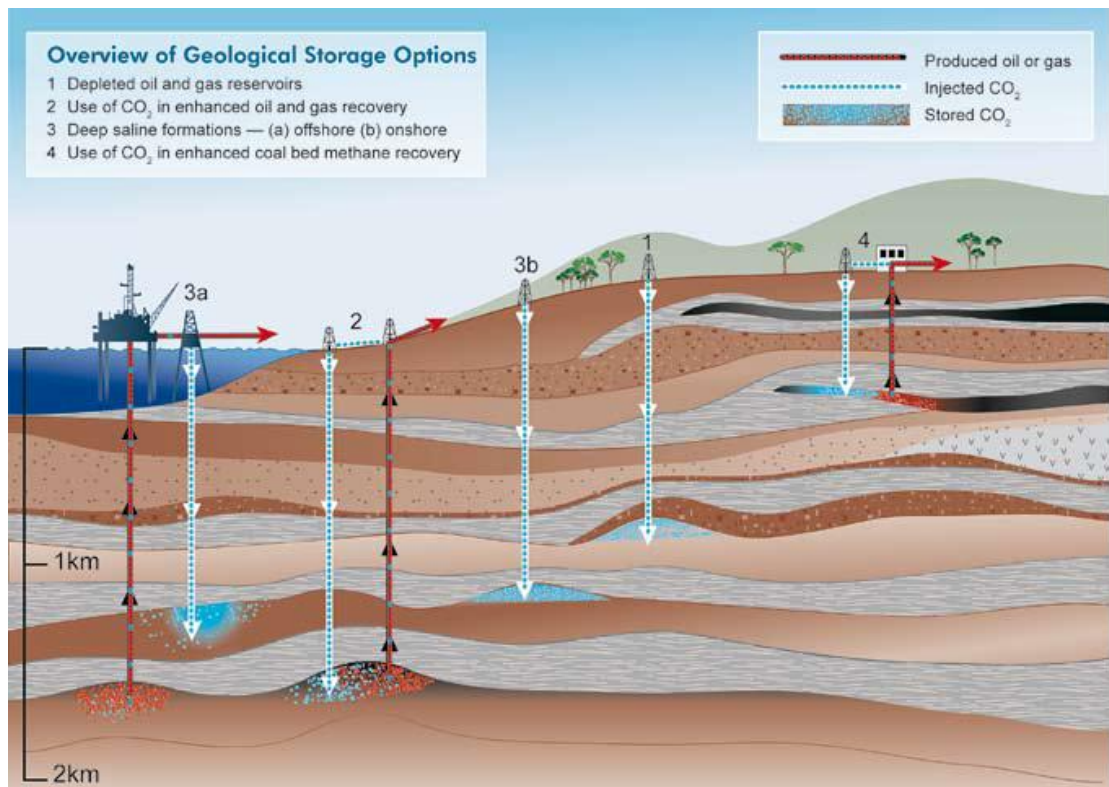


Figure 9. An overview of different geological storage options for captured carbon dioxide. (IPCC, 2005)

4.2.2 *Enhanced oil recovery*

One option for storing captured carbon dioxide from CCS is to inject the CO₂ into oil fields, using it to produce additional oil. This is called CO₂ enhanced oil recovery (CO₂-EOR). So far, CO₂-EOR has only been implemented in a few regions and most of these do not have carbon storage as a co-objective. (Godec, Kuuskraa, Van Leeuwen, Melzer, & Wildgust, 2011)

Several scientific and practical reasons account for the large volume of oil that is unrecoverable with traditional methods. The reasons include: oil that is bypassed due to poor water flood sweep efficiency; oil not physically connected to a wellbore; and, most importantly, oil trapped by viscous, capillary and interfacial tension forces as residual oil in the pore space. Injection of CO₂ can help lower the oil viscosity and trapping forces in the reservoir. Also, additional well drilling and pattern realignment for the EOR project enables contacting bypassed and occluded oil. These operations make it possible to recover oil that would otherwise be unreachable. (Ferguson, Nichols, & Kuuskraa, 2009)

4.2.3 *Storage capacity in Finland*

Finland is covered by crystalline basement rocks, which are not suitable for CO₂ storage. The same applies for near Finland sea areas in the Baltic Sea. (Teir, et al., 2010)

Within EU, the closest potential CO₂ storage sites have been discovered on-shore in the northern parts of Germany and Poland, and in southern Denmark. Potential off-shore storage sites exist in the southern end of the Baltic Sea. The nearest operational CO₂ storage sites are located off-shore in the North Sea and the Barents Sea. Due to long distances and its complexity, pipeline transportation is not considered a promising option for CO₂ transportation from Finland. (Kujanpää, Rauramo, & Arasto, 2011)

4.3 TRANSPORTATION AND STORAGE IN CASE VUOSAARI

The most likely option for carbon dioxide transportation for Vuosaari B would be ship transportation. First, the CO₂ captured in the carbon capture unit of the power plant would be compressed and liquefied in the compression unit. The liquefied CO₂ could be

transported to a nearby harbour, the Port of Helsinki in Vuosaari, and stored in an intermediate storage. The required pipeline length would be only a few hundred meters. From the intermediate storage, CO₂ is moved to a ship for transportation. Some potential storage sites are mentioned above.

In this thesis, the costs originating from carbon transportation or storage are not taken into account. Neither are the costs from building the transportation pipeline.

Naturally, ship transportation is also a source of carbon dioxide and sulphur oxide emissions. These emissions are not included in the calculations when the impact of CCS to total emissions is evaluated. In this study, the impact of carbon capture is only evaluated in relation to power plant performance and costs.

5 METHODOLOGY

5.1 PROCESS DESCRIPTION

5.1.1 Battery limits

The main battery limits of the plant are the following (see Figure 10):

- Natural gas (NG) is received via a pipeline at plant battery limit (BL)
- District heating hot water is generated in the power plant and delivered at the BL
- DH cold water returns from users to the plant at the BL
- Carbon dioxide is exported at the BL after the compression unit when the power plant is modelled with CCS
- Electrical power is exported to the local grid at plant BL
- Potable water and raw water are available at plant BL
- Waste waters are treated inside the plant. Treated water is sent at plant BL.
- Cleaned flue gas exits via the stack to plant BL

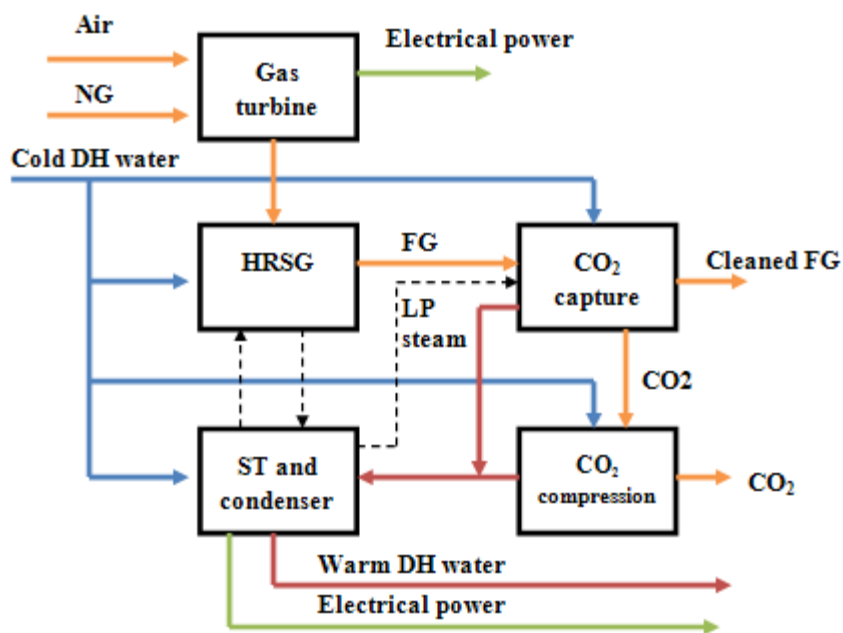


Figure 10. Overall block flow diagram of the CCGT power plant with carbon capture and compression units.

5.1.2 Fuel

The main fuel used in the power plant is natural gas produced in Russia. It is delivered via a pipeline to Vuosaari by Gasum Oy. The composition of the natural gas used in the Vuosaari power plants is presented in Table 1. Light fuel oil can be used as a backup fuel.

Table 1. Natural gas characteristics, December 2010.

Components		Mol-%
Methane	CH ₄	98,289
Ethane	C ₂ H ₆	0,631
Propane	C ₃ H ₈	0,181
Butane	C ₄ H ₁₀	0,057
Pentane	C ₅ H ₁₂	0,008
Hexane	C ₆ H ₁₄	0
Nitrogen	N ₂	0,805
Carbon dioxide	CO ₂	0,030
Oxygen	O ₂	0
Total		
Lower heating value	MJ/m ³ n	35,929
CO ₂ emission factor	tCO ₂ /TJ	55,00
Density	kg/m ³ n	0,7297
Tot. Sulphur	mg/m ³ n	<1

5.1.3 Flue gases

The concentrations of gas flows before and after gas turbines and after carbon capture for one gas turbine are presented in Table 2. Flue gases exit the heat recovery steam generators at approximately 1 bar and 53 °C.

Table 2. Vuosaari B, concentration of gas flows for one gas turbine on a full power. Fuel power 472 MW, flue gas mass flow 543 kg/s. CO₂ capture rate 90 %.

	Gas flow in the GT (kg/s)	Gas flow out of the GT (kg/s)	Flue gases after CO ₂ capture (kg/s)
Natural Gas	9.6		
Nitrogen, N ₂	422	422	422
Oxygen, O ₂	112	74	74
Nitrous oxides, NO _x		0.01	0.01
Carbon dioxide, CO ₂		21	2.1

5.1.4 Heat recovery for district heat

In the power plant model, the district heat water enters the plant at 46 °C and the T_{out} depends on the district heat demand. The heat recovery for district heat shall be made in the following sections of the power plant:

- Combined cycle, utilizing the low-grade heat available from the intermediate-pressure stages of the steam turbine
- Cold end of the Heat Recovery Steam Generator (HRSG), utilizing available heat after steam generation
- CO₂ compression unit, as cooling medium between the stages of the compressor.
- Carbon capture unit, against the condensing CO₂ rich steam, at the overhead of the stripping column.

5.1.5 Combined cycle

The combined cycle is mainly composed of two gas turbines, two heat recovery steam generators that generate steam at two levels of pressure, and a steam turbine.

Natural gas from the distribution grid is compressed at the suitable pressure to feed the gas turbines and is then combusted to generate electric power. From the gas turbines, the exhaust gases are conveyed to the heat recovery steam generator. Gas turbine exhaust gases enter the HRSG for generating steam at two pressure levels that are presented in Table 3.

Table 3. The characteristics of HP and LP steam flows of the VuB power plant.

Name	Pressure, bar	Temperature, °C	Flow rate, kg/s
High pressure (HP)	75	510	2 x 68
Low pressure (LP)	7,5	220	2 x 14

The flue gases enter the HRSG at the temperature of 543 °C and exit after the cold DH heater at 52 °C. The flue gases face the following heat exchangers when flowing horizontally inside two HRSGs:

- HP superheater;
- HP evaporator;
- HP economiser second section;
- LP superheater;
- LP evaporator;
- HP economiser first section and LP economiser; heat exchangers are placed in a parallel arrangement;
- DH heater (hot);
- DH heater (cold).

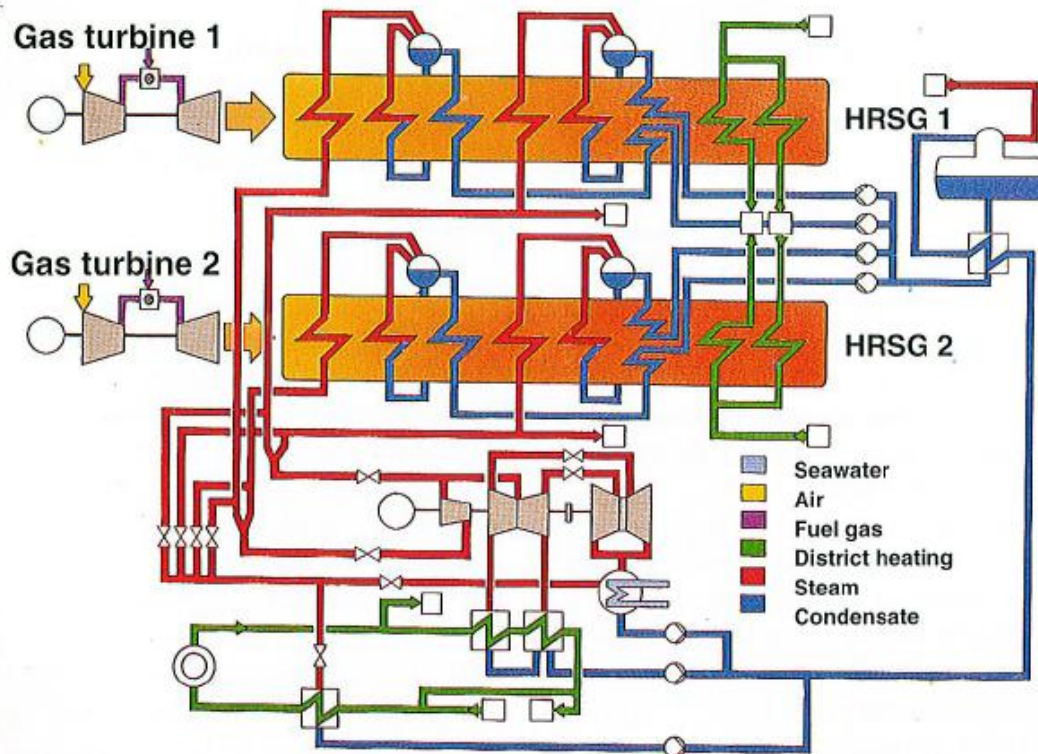


Figure 11. Vuosaari B process flow diagram. (Modern Power Systems, 1995)

The high pressure (HP) steam entering the HP module of the steam turbine comes from the HP superheater of the HRSG. Exhaust steam from the HP module of the steam turbine is mixed with the superheated low-pressure (LP) steam generated in the HRSG. Since the LP steam flow is not enough to satisfy the heat requirement of the reboiler of the carbon capture unit, a part of the mixed flow is extracted and led to the carbon capture unit. The rest of the steam is fed to the intermediate-pressure (IP) module of the steam turbine. After the IP module, the exhaust steam is routed to the district heat exchangers where it is condensed. In case of lower district heat demand, the exhaust steam can be fed to the LP module of the steam turbine, to increase the electricity generation. Steam is then condensed by sea-water in the condenser. Figure 11 presents the process flow diagram of Vuosaari B (gas turbines and HRSGs numbered as 1 and 2 are in reality 4 and 5).

5.1.6 Carbon capture unit

Appendix C illustrates the connections in the carbon capture unit. The temperature of the flue gas after the HRSG is quite low, only around 52°C. The flue gas from the power plant flow would probably be split in two identical parts before entering the

absorber. The reason for this is the large volume of the flue gas flow. By splitting the flue gas flow, one, otherwise very large, absorption column can be replaced by two smaller ones. Additionally, this would probably make it easier to operate the carbon capture on partial loads. Each gas flow is cooled to approximately 40°C in direct contact with cooling water in Direct Contact Cooler Drum. The cooled flue gas stream is fed to the absorption tower by a flue gas blower. In the absorption columns, the entering gas is contacted with a lean solvent solution (30 %-wt MEA), which allows approximately 90% carbon capture rate with respect to the gas stream entering the unit.

Two CO₂ free flue gas flows are scrubbed before leaving the absorption column with make-up water to remove possible solvent remains and avoid emissions into the atmosphere. After the absorption column, two gas flows are joined and sent to the stack.

The rich solvent flows from the bottom of the two absorption towers and they are combined and then heated in a regenerative gross exchanger before it is sent to a regeneration column. The regeneration column consists mainly of a stripping section. Solvent regeneration requires heat which is delivered by low pressure steam to the stripper reboiler. The condensate is pumped from the reboiler to the district heat exchanger to recover remaining heat. The temperature of the stripper is estimated to be 100-140 °C, in this case the chosen value is 120 °C.

After solvent regeneration, the vapour is led through a condenser, where it is cooled with DH water. The rich CO₂ stream is then sent to the compression unit.

The most significant energy penalty is due to the requirement of extraction steam from the steam turbine to the stripper in the carbon capture unit. The heat consumption will be approximately 3-5 MJ/kgCO₂ (3.8 MJ/kgCO₂ used in the calculations). Of the heat consumption, approximately 50 % is used to break the chemical bond between the absorbent and CO₂. The rest is used to the supply of sensible heat for the temperature cycling and heat losses from the system. The heat losses consist of both convective and radiation losses as well as evaporation losses for the absorbent and water from the stripper. (Bolland & Undrum, 2002)

In the carbon capture unit, the main electricity consumer is the exhaust gas fan, which is needed to overcome the flue gas pressure drop in the absorption towers. A value of 0.34 MJ/kg CO₂ (150 mbar pressure drop through the absorber) was chosen for fan work.

The additional power demand, caused mainly by pumps, in the capture unit was estimated to be 0.05 MJ/kg CO₂. (Bolland & Undrum, 2002)

In some examples found in the studies made previously, the steam for the carbon capture unit is extracted either from the low-pressure steam header and returned to LP economiser or before the LP module of the steam turbine and returned to the LP steam header. In VuB, the LP steam flow is not enough to satisfy the heat requirement of the reboiler of the carbon capture unit. Therefore, the reboiler steam is extracted before the IP module of the steam turbine and the condensate is fed to the district heat exchanger, where some of the excess heat can be recovered. This is possible to implement without extensive alterations to the process of the existing power plant. After IP module, the pressure and temperature levels of the steam are too low for solvent regeneration.

5.1.7 CO₂ compression unit

The carbon dioxide captured in the carbon capture plant need to be compressed and pumped to 110 bar, before it can be transported. The CO₂ compression unit consists of a one electrically driven multi-stage compressor, a dehydration unit, the required intercoolers and a centrifugal pump. The humidity is removed from the CO₂ stream in the dehydration unit and the gas flow is dried. After drying, CO₂ is compressed in the last stages of the compressor and is then liquefied with cooling water and pumped up to desired pressure. Finally, the CO₂ is sent via a pipeline outside the battery limits of the power plant.

5.2 MODES OF OPERATION OF THE POWER PLANT

The steam turbine in Vuosaari B is a back-pressure turbine with a condensing option. There are three ways to run the VuB power plant: back pressure, mixed and condensing mode. The process is modelled for each option in the original case and with the carbon capture unit. It is also possible to generate more district heat by bypassing the steam turbine, but it happens rarely due to the sizing of the reduction heat exchanger (50 % of the full capacity) and of the high price of energy generated with this operation mode. Therefore, this kind of operation mode is not modelled in this thesis. (Hanioja, Vuosaaren B-voimalaitos: Kaukolämpöjärjestelmän järjestelmäkuvaus, 2009)

Operation on partial load was not modelled. In partial loads, power plant overall efficiency drops. If necessary to run on partial loads, it is usual, that one of the gas

turbines would be run down, and the other one is run on full load. However, operation on partial loads should be considered when designing CCS retrofit.

5.2.1 *Back pressure mode*

When running the power plant on the back pressure mode, the low-pressure turbine is not in use. All steam is fed to the district heat exchangers after IP turbine. The condenser is kept on standby, since if the power plant had to be run down all steam is primarily led to the condenser. District heat is generated by district heat exchanger 1 and 2 and by the heat exchangers in the heat recovery steam generators. (Hanioja, Vuosaaren B-voimalaitos: Kaukolämpöjärjestelmän järjestelmäkuvaus, 2009)

The back pressure mode is the most used in Vuosaari B during winter time, when district heat demand is high in Helsinki.

5.2.2 *Mixed mode*

In the mixed mode, all the stages of the steam turbine, including the low-pressure stage, are in use and district heat is generated by heat exchangers 1 and 2 and by the heat exchangers in the heat recovery steam generators. In mixed mode, a part of the low-pressure steam is lead to the low-pressure turbine (at the minimum 10%) and the rest is extracted from the intermediate-pressure turbine to the heat exchangers. (Hanioja, Vuosaaren B-voimalaitos: Kaukolämpöjärjestelmän järjestelmäkuvaus, 2009)

The mixed mode is the most common way to run VuB during summer time, when heat demand is lower and power-to-heat ratio is wanted to keep higher.

5.2.3 *Condensing mode*

In the condensing mode, no district heat is generated. All steam flows from the the intermediate-pressure stage to the low-pressure stage. After the low-pressure stage, steam is condensed in the condenser, district heat exchanger are not in use. (Hanioja, Vuosaaren B-voimalaitos: Kaukolämpöjärjestelmän järjestelmäkuvaus, 2009)

Nowadays, the operation on the condensing mode is relatively unusual in VuB. The condensing mode is used primarily during summer time, when heat demand is low and the price of electricity is high. During the coldest months, it is not exceptional that the low-pressure stage of the steam turbine is not used at all.

The carbon capture unit and compression unit are expected to use DH water for cooling also in the condensing mode. The excess heat can be stored in a heat battery located in Vuosaari power plant area.

5.3 POWER PLANT MODELLING AND SIMULATIONS

A combined cycle gas turbine power plant was modelled with Prosim, software created for process modelling. The modelled power plant is based on an existing power plant, Vuosaari B in Helsinki. The process of the existing power plant was simplified, only the main process is modelled. The main process consists of two gas turbines; two heat recovery steam units; a steam turbine with high-pressure, intermediate-pressure and low-pressure stages; district heat exchangers; a condenser and a feed water tank. The figure of the power plant model made with Prosim can be found in appendix B.

Process values were received from the operation personnel of Vuosaari power plants. Process values are received from hourly measurements made in the year 2010. Values used in simulations were the calculated averages of the hourly values. Data from the hours during power plant shut downs due to maintenance operations or other reasons were excluded from the calculations.

The first model represents the current process of VuB. The model can be considered to represent the power plant process quite well, even though it is only a simple model.

The existing process was simulated three times, in every mode of operation of the power plant: back pressure mode, mixed mode and condensing mode. In the model, the gas turbine operation is similar in each operation mode, thus the flue gas flows remain more or less unchanged. The differences are in the steam use in the steam turbines and heat exchangers.

In reality, there are two intermediate and low pressure stages in the steam turbine. In the model, the steam turbine is simplified so that there are only one intermediate pressure stage (number 2 in Figure 12) and one low pressure stage (number 3 in Figure 12).

In the second model, the heat flows in and out of the carbon capture unit and the compressor unit are integrated into the previous model. The new units are simulated separately. Due to the fact that no precise information about the flows inside a carbon capture unit is available, the unit is modelled with two heat exchanges. The other one represents the heat demand of the solvent stripper (number 5 in Figure 12), which can

be estimated according to values found from the resource material. In this model, the heat demand is estimated to be 3.8 MJ/kgCO₂ according to estimates found in several studies. The required heat is delivered by low pressure steam (7.5 bar in VuB) upstream intermediate pressure steam turbine. This was discovered to be the only viable way to extract steam for the reboiler. The other option for extraction was the LP steam header, but in there the steam mass flow is not large enough to satisfy the heat demand of the reboiler. After the reboiler, the condensed steam is fed to the district heat exchanger (number 4 in Figure 12).

The other heat exchanger enables heat recovery from the carbon capture unit. It heats district heat water by condensing carbon dioxide and steam that exit the stripper in the temperature approximately 120°C (see Appendix C).

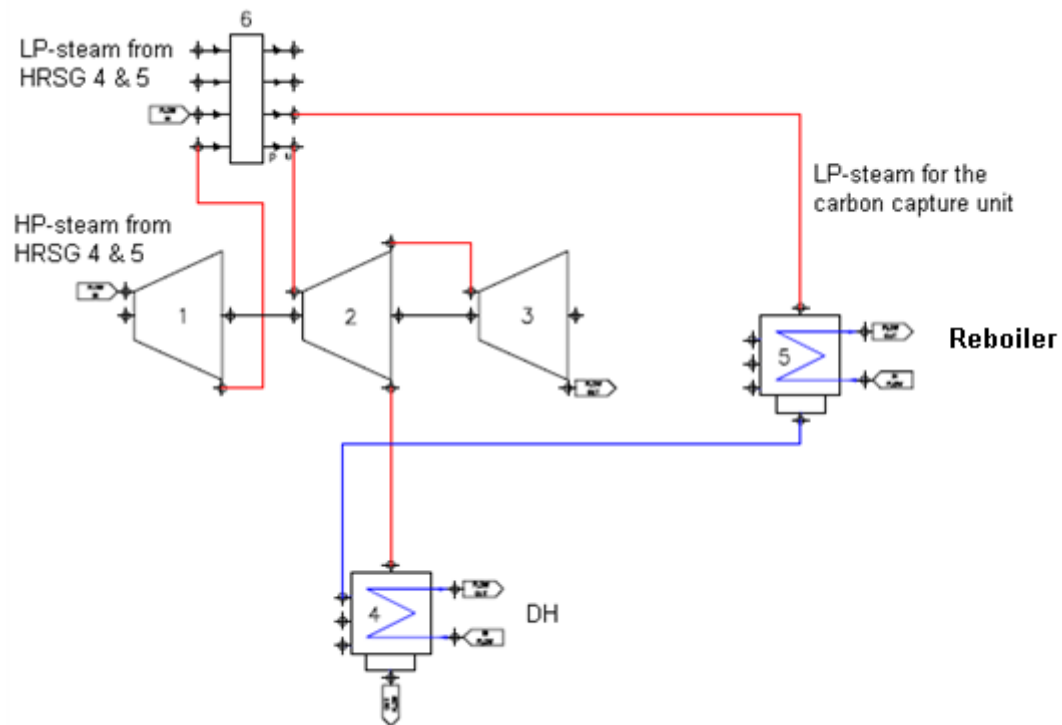


Figure 12. LP-steam extraction before MP turbine for the reboiler of the carbon capture unit. This model was utilized for heat flow simulations of the carbon capture unit.

Carbon dioxide produced by the carbon capture unit has to be compressed and then pumped to 110 bar, before it can be exported via a pipeline. The CO₂ compression unit consists of one electrically driven multi-stage compressor. The compressor has four stages and required intercoolers. In reality, the unit would also have a dehydration unit where the gas is dried before compression to desired pressure. To keep the model

simple enough, the dehydration unit and condensate draining facilities were not included in the model. After each compression level, there is an intercooler utilizing district heat water for gas stream cooling. After the CO₂ is liquefied and pumped up to the desired pressure, it is sent to the outside battery limits of the plant via a pipeline. The model for CO₂ compression unit simulation is presented in Figure 13.

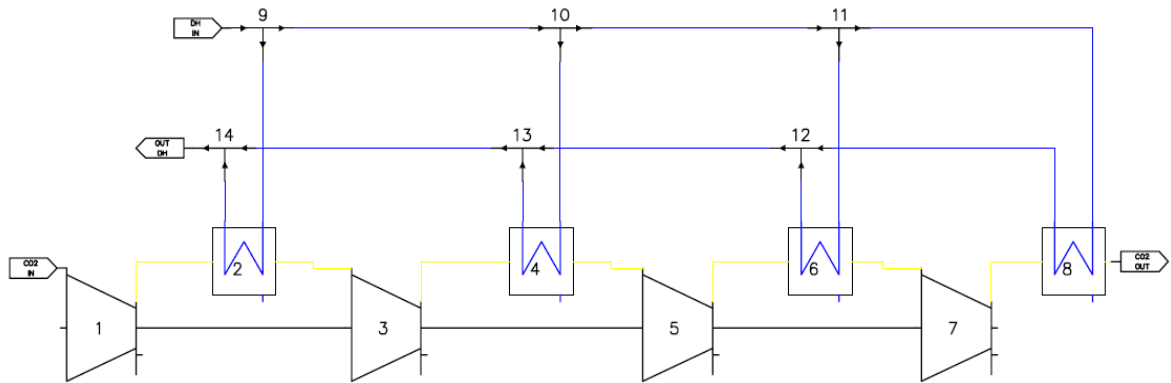


Figure 13. CO₂ compression unit with four compression units and intercoolers. The model was utilized to simulate heat flows in the compression unit.

Also the process after carbon capture retrofit is simulated in all the three modes of operation. Thus, a total of six cases were simulated in order to receive the desired data. Results from the simulations are presented in Chapter 7.1.

6 COSTS

The estimates for the costs of carbon capture and storage vary greatly. Among other things, they depend strongly on operation environment and location. Also the investment costs in industry have risen as a consequence of the risen material and labour costs during last few years. This makes comparison difficult. (Teir, et al., 2011)

Figure 14 presents one estimate for the total cost of early commercial CCS projects.

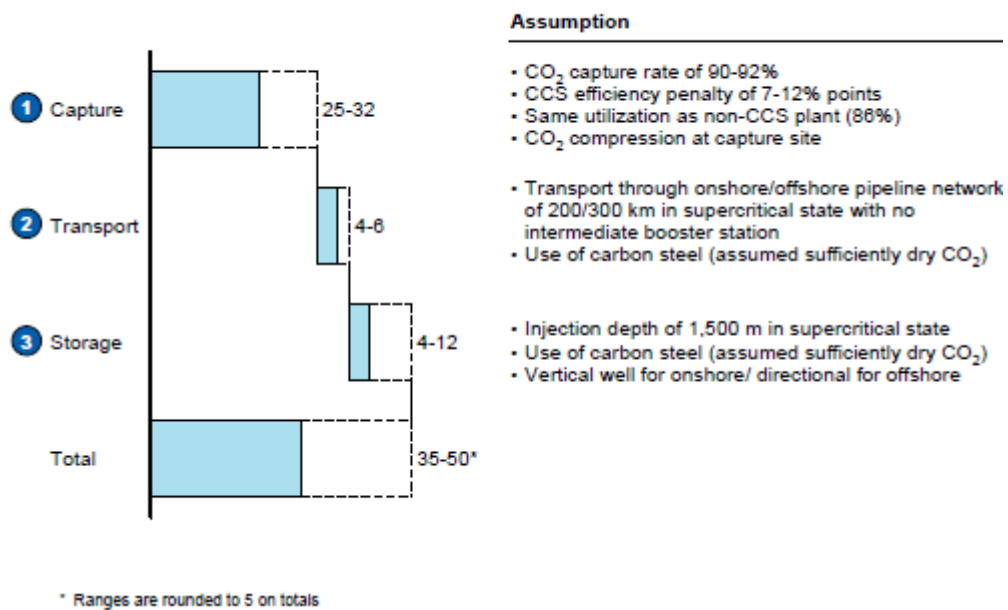


Figure 14. Total cost of early commercial carbon capture and storage projects (reference case). €/t CO₂ abated; ranges include on- and offshore storage. (McKinsey & Company, 2008)

6.1 CARBON CAPTURE COSTS

6.1.1 Investment cost estimate

The investment cost for post-combustion CO₂ capture from natural gas –fired CCGT plants is estimated to be a relatively small part of the total cost penalty for CO₂ abatement, about 30 % of the total. (Gibbins, 2009)

The investment costs consist of two units: carbon capture unit and CO₂ compression and liquefaction unit and an intermediate storage with other transportation equipment in

the harbour. The overall investment cost of each unit can be split into the following items:

- Direct materials:
 - o Equipment
 - o Bulk materials: including the steel structure, piping materials, system for fire fighting, field instruments, electrical equipment and transport of the equipment.
- Construction: including mechanical erection, electrical and instrument installation, painting, insulation and buildings.
- Other costs: Including temporary facilities for construction, assistance for commissioning and technical vendor advisor on site.
- EPCM services: Engineering, Procurement, Construction management, including Contractor's home office services, construction supervision and commissioning.

The actual cost of CCS retrofit is likely to vary from project to project. Greenfield plant designs have the advantage of working with sites that are more flexible concerning space. The extra element of difficulty arises, when CCS retrofit projects have to be carried out in the confines of usually already cramped sites. Important design issues that should be considered are: working around existing structures (such as buildings and pipe racks), limitations on site access, having to work with existing site utility infrastructure (for instance, water purity issues and resource availability). These types of complications will add extra costs and challenges to any CCS retrofit project. Additionally, these costs are very difficult to quantify in advance and they are likely to vary greatly from one project to another. (National Energy Technology Laboratory, 2010)

The cost of avoiding CO₂ emissions is estimated to be 48 – 102 \$/t CO₂ for natural gas fired power plants. Costs per tonne of CO₂ are higher for the gas fired plants than for coal fired plants (27 – 39 \$/t CO₂), because less CO₂ emission is avoided per kWh of electricity generated. (Davidson, 2007)

A fraction of the inlet-air of the gas turbine compressor can be replaced by recycled flue gas. This might reduce the capital cost even further, due to smaller gas flows processed in the capture unit. Upstream of the recycling point, the gas stream would be unchanged

for the rest of the power plant. Flue gas recycling would also increase CO₂ concentrations, making high levels of capture easier. (Gibbins, 2009)

6.1.2 Operating and maintenance costs

The variable operating costs mainly include the following:

- Natural gas
- Raw water make-up
- MEA solvent
- Other chemicals

The fixed operating costs include:

- Operating labour costs
- Overhead charges
- Maintenance costs

For CO₂ abatement, the main additional cost is the extra fuel. Extra fuel has to be burned, because of the power plants reduced efficiency due to energy required by the capture unit and compression equipment. Approximately 20 % of the cost penalty is operating expenses, mostly solvent consumption. (Gibbins, 2009)

In this case, the fuel power of the Vuosaari B power plant doesn't change after CCS retrofit. Instead, the thermal and electrical power decreases due to lower efficiency. To cover the unchanged need for heat and electricity, the extra fuel would have to be burned in other power plants in Helsinki.

6.1.3 Revenues

The products of the power plant are electric power, district heating and carbon dioxide. The prices used for calculations in this thesis are presented in the table 4 below.

Table 4. The used revenues for the cost estimates.

Electricity	46 €/kWh
District heat	30 €/kWh
Emission allowance	25 €/t

The actual price of the decreased district heat generation resulting from losses in thermal efficiency is difficult to evaluate. If less DH is generated in VuB, more district heat has to be generated in other power plants not as efficient as VuB (before CCS retrofit). The heat demand of district heat users in the district heating network has to be satisfied constantly. There must be enough generation capacity and stand-by power plants during every hour of the year. The aim is to complete the heat demand in the most profitable and energy-saving way, and additionally keeping the green house gas emission as low as possible. It is possible to use either cogeneration power plants or district heating plants, simultaneously paying attention to the usability of the power plants, which can be limited due to reasons such as maintenance breaks.

In Helsinki, the Vuosaari cogeneration power plants are considered the most efficient option for electricity and district heat cogeneration. There are also coal-fired cogeneration plants. District heating plants use mainly heavy fuel oil or natural gas. So, if the heat power of Vuosaari B sinks, the heat demand need to be satisfied with other, less efficient power plants and district heating plants. This creates costs and emissions, which are not estimated in this thesis due to their complexity. Nevertheless, they should be taken into account before making decision on whether to make this investment on CCS or not. Here, a cost estimate is given to DH to get a rough evaluation of the overall costs related to CCS retrofit.

6.2 TRANSPORTATION

The costs of carbon dioxide transportation can be estimated quite well since there is a lot of experience of pipeline transportation. Of transportation by ship, there is a lot less experience, but some cost estimates exist. Although, it should be noted that in the

estimates it is usually assumed that the storage sites can be found near the power plant, about 200-300 km away. In Finland, the distance from the largest CO₂ sources to the known possible storage sites in North Sea, the Barents Sea or in Germany is approximately 500-1500 km. Therefore, transportation costs for CCS plants in Finland are likely to be significantly higher than for plants elsewhere in Europe. The estimated costs for pipeline transportation found in the literature vary between 0.5-5.1 €/ (tCO₂*100 km). Respectively, cost estimates for ship transportation vary between 0.4-3.4 €/ (tCO₂*100 km). (Teir, et al., 2011)

The amount of CO₂ captured per year is approximately 1.0 Mt (based on the production data of VuB).

6.3 STORAGE

CO₂ injection well costs can be evaluated by using known costs for drilling oil and gas wells. The main alteration is caused by the additional costs of well bore isolation (usually cementing). The cost of installing and running CO₂ monitoring equipment is typically low in comparison with the storage costs. The costs for offshore well increase as a function of water depth and well complexity, and they can be more than four times higher than for onshore wells even in shallow water environments. (IEA, 2008)

If the carbon dioxide is utilized for enhanced oil recovery (EOR), the revenue from enhanced oil production could in some cases be even greater than the total cost of carbon capture, transport and storage. However, if CCS would become widely applied technology, most of the CO₂ would have to be stored in deep saline aquifers and this would generate no revenue. (Davidson, 2007)

7 RESULTS

7.1 EFFECTS ON THE PROCESS

The power plant process was modelled in the three modes of operation of the power plant: the back pressure mode, mixed mode and condensing mode. In each operation mode, the effects of CCS retrofit on the original process were evaluated. The plant thermal input can be considered the same before and after implementing CCS. In this model, the gas turbines are not changed when the carbon capture unit is added to the power plant. Therefore, also the gas turbine electrical output is considered to remain unchanged.

VuB is rarely operated on partial loads, and that is why they are not modelled. The efficiency of VuB decreases on partial loads. If energy demand sinks, Helsingin Energia's coal and oil-fired district heating plants are first to reduce their generation, while they usually have higher generation costs and emission rates than natural gas-fired Vuosaari power plants. During low district heat demand periods, VuB can be operated with one gas turbine at the time.

The heat required by the reboiler of the carbon capture unit is delivered by condensing low-pressure steam. When the heat demand for the absorption process is 3.8 MJ/kg CO₂, the required mass flow for low pressure steam (7.5 bar; 220 °C) is approximately 80 kg/s. Approximately 2 MJ/kgCO₂ is used for breaking the chemical bond between capture carbon dioxide and MEA solvent. The rest, 1.8 MJ/kgCO₂ is needed to cover the heat losses of the capture unit and to provide sensible heat for the temperature cycling.

As the plant thermal input is virtually the same in each modelled mode of operation, the flue gas mass flow also remains unchanged. Therefore, also the steam requirement for different operation modes is similar in the models. The electricity output of the high-pressure turbine remains the same.

Low pressure steam for heating the desorber tower is extracted before the intermediate pressure turbine. Due to lower steam flow left for the intermediate pressure steam turbine, the electrical output of the steam turbines decreases. The electrical efficiency of the steam turbine does not change notably even though the steam mass flow decreases

radically. The condensate from the carbon capture unit is returned upstream of the district heat exchanger, so the remaining heat can be recovered as district heat. Still, the thermal output of the heat exchanger sinks radically as shown in tables 5, 6 and 7. In the condensing mode, the recovered heat from the carbon capture mode can be stored in a heat battery if not needed elsewhere.

The following tables show the power generation efficiencies during normal operation in the back pressure mode, the mixed mode and in the condensing mode. In each table, process values are first presented for current situation before CCS retrofit, and then with carbon capture unit and compressor equipment. The model of the existing plant can differ from reality in some respects, but the aim is specifically to illustrate the changes in process values that are caused by CCS.

District heat is recovered from the carbon capture unit after the solvent stripper. The heat exchanger cools the CO₂-rich steam that also has some water and solvent vapour from the desorber temperature (approximately 120 °C) to 50 °C before it is compressed in the compression unit.

In the back pressure mode, as presented in table 5, net electrical output sinks by 45.4 MW after CCS retrofit. This is due to the dropped power generation of the intermediate-pressure steam turbine and increased auxiliary electrical consumption caused by the carbon capture and compression unit. District heating thermal power drops by 118.1 MW. Most of the heat is utilized to satisfy the heat requirement of the chemical reaction in the desorber. The power-to-heat ratio of the power plant rises from 0.9 to 1.1. This is primarily due to the fact that the heat power of the plant decreases more than electrical power. The auxiliary electrical consumption of the CO₂ capture and compression units is considered to remain more or less the same regardless of the mode of operation.

Table 5. Overall plant performance before and after carbon capture retrofit in back pressure mode of operation.

	Before CCS retrofit	After CCS retrofit
District heating temperature		
Inlet temperature, °C	46	46
Outlet temperature, °C	103	88
Plant thermal input		
Thermal energy of NG (LHV basis), MWth	919,2	919,2
Plant electrical output		
Gas turbine, MWe	306,9	306,9
Steam turbine, MWe	119,3	110,7
Total, MWe	426,2	417,6
Gross electrical efficiency (LHV basis), %	46,4 %	45,4 %
Auxiliary Electrical consumption		
Power Plant, MWe	14,2	14,2
CO ₂ capture, MWe	0,0	17,3
CO ₂ compression, MWe	0,0	19,5
Net electrical power output	412,0	366,6
Net electrical efficiency, %	44,8 %	39,9 %
Plant thermal output		
DH from CCGT, MWth	442,8	302
DH from CO ₂ capture unit, MWth	0,0	3,4
DH from CO ₂ compression unit, MWth	0,0	19,3
District heating thermal power, MWth	442,8	324,7
Thermal power efficiency, %	48,2 %	35,3 %
Overall plant efficiency		
Electrical and district heating	93,0 %	75,2 %
Power-to-heat ratio	0,9	1,1
CO ₂ capture rate, %	0 %	90 %
CO ₂ emitted flowrate, kg/s	49,3	4,9

Table 6. Overall plant performance before and after carbon capture retrofit in mixed mode of operation

	Before CCS retrofit	After CCS retrofit
District heating temperature		
Inlet temperature, °C	46	46
Outlet temperature, °C	98	87
Plant thermal input		
Thermal energy of NG (LHV basis), MWth	919,3	919,3
Plant electrical output		
Gas turbine, MWe	306,9	306,9
Steam turbine, MWe	130,5	112,5
Total, MWe	437,4	419,4
Gross electrical efficiency (LHV basis), %	47,6 %	45,6 %
Auxiliary Electrical consumption		
Power Plant, MWe	14,6	14,6
CO ₂ capture, MWe	0,0	17,3
CO ₂ compression, MWe	0,0	19,5
Net electrical power output	422,9	368,0
Net electrical efficiency, %	46,0 %	40,0 %
Plant thermal output		
DH from CCGT, MWth	400,3	292,3
DH from CO ₂ capture unit, MWth	0,0	3,4
DH from CO ₂ compression unit, MWth	0,0	19,3
District heating thermal power, MWth	400,3	315,0
Thermal power efficiency, %	43,5 %	34,3 %
Overall plant efficiency		
Electrical and district heating	89,5 %	74,3 %
Power-to-heat ratio	1,1	1,2
CO ₂ capture rate, %	0 %	90 %
CO ₂ emitted flowrate, kg/s	49,3	4,9

In mixed mode, net electrical output sinks by 54.9 MW according to the model. This is caused by dropped power generation in the IP and LP stages of the steam turbine and increased auxiliary electrical consumption in the carbon capture and compression unit. District heating thermal power drops by 85.3 MW in mixed mode. Most of the heat is lost when trying to satisfy the heat requirement of the chemical reaction in the desorber.

Also in mixed mode, power-to-heat ratio of the power plant is higher after CCS retrofit. Results from simulations made for the mixed mode are presented in Table 6.

Table 7. Overall plant performance before and after carbon capture retrofit in condensing mode of operation

	Before CCS retrofit	After CCS retrofit
District heating temperature		
Inlet temperature, °C	-	-
Outlet temperature, °C	-	-
Plant thermal input		
Thermal energy of NG (LHV basis), MWth	919,2	919,2
Plant electrical output		
Gas turbine, MWe	306,9	306,9
Steam turbine, MWe	229,0	144,6
Total, MWe	535,8	451,5
Gross electrical efficiency (LHV basis), %	58,3 %	49,1 %
Auxiliary Electrical consumption		
Power Plant, MWe	17,4	17,4
CO ₂ capture, MWe	0,0	17,3
CO ₂ compression, MWe	0,0	19,5
Net electrical power output	518,5	397,3
Net electrical efficiency, %	56,4 %	43,2 %
Plant thermal output		
DH from CCGT, MWth	0,0	0,0
DH from CO ₂ capture unit, MWth	0,0	3,4
DH from CO ₂ compression unit, MWth	0,0	19,3
District heating thermal power, MWth	0,0	22,7
Thermal power efficiency, %	0,0 %	2,5 %
Overall plant efficiency		
Electrical and district heating	56,4 %	45,7 %
Power-to-heat ratio	-	-
CO ₂ capture rate, %	0 %	90 %
CO ₂ emitted flowrate, kg/s	49,3	4,9

Process values for the condensing mode are presented in Table 7 above. When running the CCS retrofitted power plant on the condensing mode, the net electrical power is 121.1 MW lower than before CCS retrofit. As the steam for the reboiler is extracted after the high pressure turbine, the electrical output is lower in both intermediate-pressure and low-pressure turbine stages. For overall efficiency, this means a radical drop from 56.4 to 45.7 %.

Figure 15 illustrates the changes in thermal and electrical power generation in all three operation modes before and after CCS retrofit. It can be seen, that the difference between mixed mode and back pressure mode are quite small after CCS retrofit. Therefore, the modes of operation of the power plant would probably have to be reconsidered if decided to do the retrofit.

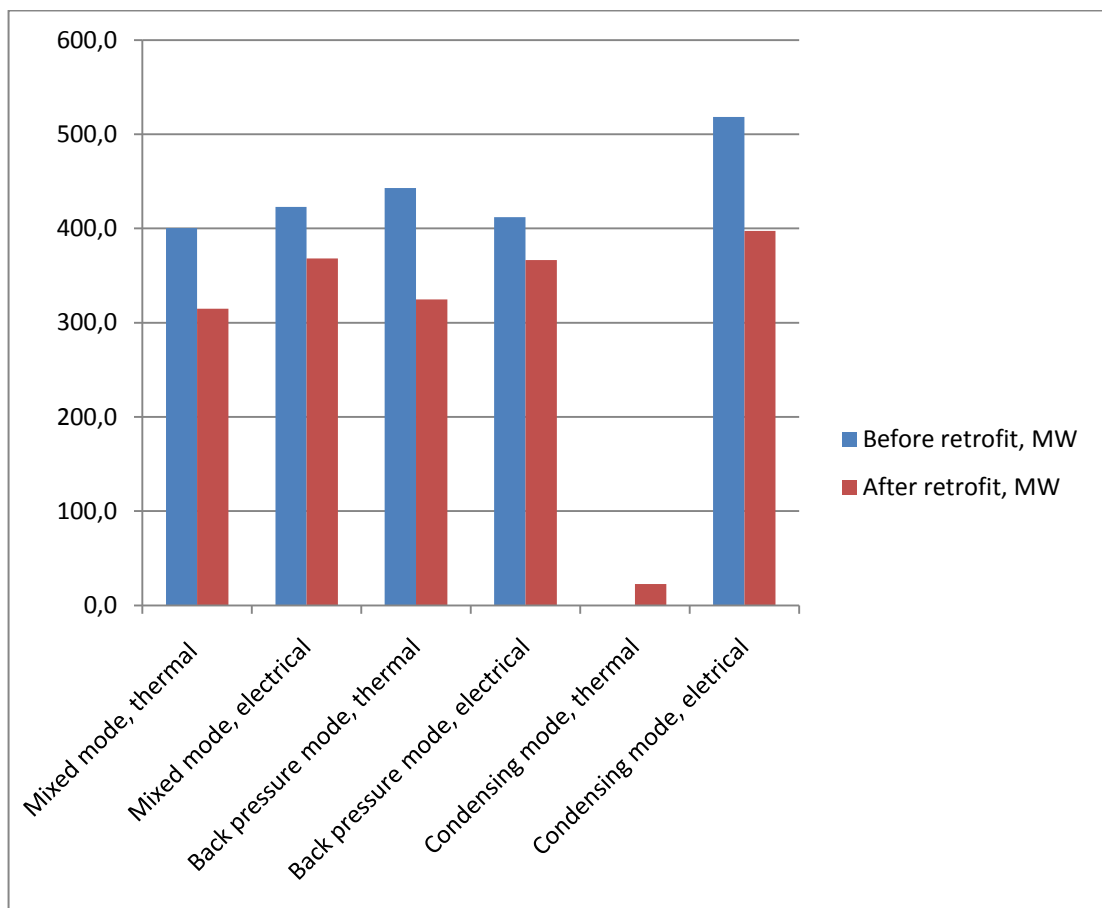


Figure 15. Changes in electrical and thermal power before and after carbon capture retrofit for each mode of operation of the power plant.

For clarity, the mass flow of district heat water is constant in the calculations before and after CCS retrofit. The temperature of the incoming district heat water is 46 °C in each case. After retrofitting CCS to the CCGT process, the outlet temperature of DH water

decreases due to lowered heat power. In reality, the district heat water mass flow is not constant.

The drop in total efficiencies is the most significant in the back pressure mode, 17.8 percentage units. Presumably this is caused by the fact that the drop is the biggest in heat power, which naturally affects most in the back pressure mode. After CCS retrofit, the power plant generates nearly as much electrical power as heat power. In mixed mode, total efficiency is 15.2 percentage units lower with CCS and in condensing mode 10.7 percentage units lower.

7.2 EFFECTS ON THE CO₂ EMISSIONS

The decrease in overall CO₂ emissions is not as big as the CO₂ capture rate of the carbon capture unit. The fuel use increases due to losses in the overall efficiency of the power plant thus increasing the green house gas production. The extra fuel is also needed to generate the energy required for CO₂ transportation and storage. Additionally, it is possible that there are leakages during CO₂ transportation. Figure 16 illustrates the proportion of the avoided CO₂ emissions to the captured CO₂.

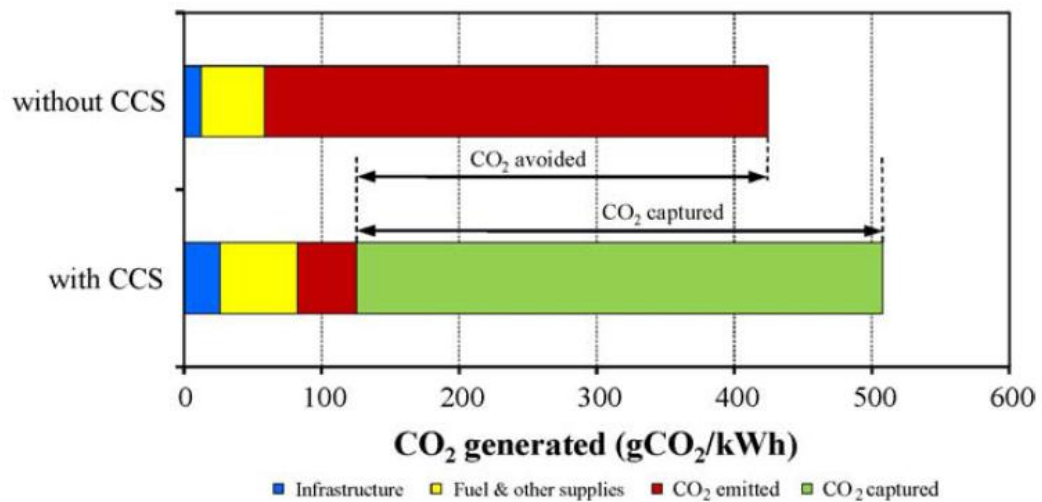


Figure 16. The total CO₂ production increases as a result of losses in overall efficiency of the power plant, transport and storage, and possible leakages during transport. (Singh, Stromman, & Hertwich, 2011)

As thermal efficiency would go down in Vuosaari B as a result of CCS, the district heat demand remains the same. This would mean an increase in the use of other power

plants and district heating plants, which are more expensive to use for energy generation than VuB. District heating plants use natural gas and also oil as a fuel, which produces more CO₂ and other emissions than the relatively clean natural gas used in VuB. It is difficult to estimate how much the overall emissions in Helsinki would decrease as a consequence of introducing CCS in VuB. This depends on the current order of operation of the power plants.

In VuB itself, the yearly emissions would sink from the original 1,1 Mt/CO₂ (average emissions calculated on the grounds of yearly natural gas consumption) to 0,1 Mt/CO₂, if the separation rate was the estimated 90 %. The CO₂ capture rate of 90 % from the flue gases enable avoiding 70 % per kWh of total CO₂ emissions into the atmosphere and results in reducing global warming potential (GWP) by 64 % (Singh, Stromman, & Hertwich, 2011).

7.3 EFFECTS ON THE COSTS

The cost estimates are made on a general level on purpose. The main focus of interest in this thesis is the effect that CCS has on the power plant process. The cost estimates are merely to give an indication of the costs involved in the CCS implementation.

Investment costs to carbon capture unit and compression equipment large enough for required flue gas mass flow are approximately 177 M€, ±50 % accuracy. More precise price information could be obtained by calling for offers from different licensors. For illustration, in a green field power plant with CCS the CO₂ capture and compression unit investment costs represents approximately 30 % of the total investment costs. Additional costs resulting from building the necessary pipelines for LP steam, flue gases, condensate and separated CO₂ flows are not included in the investment costs. (Foster Wheeler, 2010)

To evaluate maintenance costs precisely, the costs would have to be broken down amongst the numerous components of the capture plant. These kinds of costs depend mostly on the type of equipment selected for the plant. Evaluation of this accuracy is considered premature at this stage. The annual maintenance cost of the carbon capture and compression unit is evaluated to be 2 % of total investment costs, which would be 3.54 M€/year (Foster Wheeler, 2010).

When using chemical absorption as the carbon capture technology, the need for chemical solvent also creates costs that should be included in the cost evaluations. The cost of MEA solvent is 3850 €/t (Foster Wheeler, 2010) and the need for MEA makeup due to solvent degradation is approximately 1.5 kg/tCO₂ (Rao & Rubin, 2002).

Rise in the price of emission allowances will make Vuosaari power plants more profitable compared with other, coal-using power plants of Helsingin Energia. In the coming years, the utilization rate is expected to remain high. (Hanioja, Vuosaaren voimalaitosten pitkän tähtäyksen suunnitelma, 2010)

The change in revenues after implementing carbon capture is shown in the following Table 8. District heat and electricity generation is approximated according to data of VuB from recent years. Heat and electricity generation would decrease significantly, thus bringing the revenues down. The revenues from captured CO₂ depend on emission allowance prices.

Table 8. The unit prices and CCS related changes in the revenues.

Product	Unit price		Generation before CCS yearly		Change in generation	Change in revenues M€/year
Electricity						
CHP	46	€/MWh	3141367	MWh/y		
Condensing mode	46	€/MWh	172356	MWh/y	-298235,07	-13,71881
District heat	30	€/MWh	2866251	MWh/y	-687900,24	-20,63701
CO₂	25	€/t	989395	t/y	989395	24,734875
Total						-9,620945

Table 9 presents the estimated costs and revenues for 25 years of operation. The carbon capture unit is introduced in 2015. The present value is also calculated using 5 % as a discount rate. For electricity and district heat, the revenues are presented as how they would change for the present due to CCS retrofit.

Table 9. Investment and solvent costs and changes in revenues and power plant's maintenance costs and their present values after CCS implementation for power plant life cycle (25 years). Carbon dioxide marked as a negative cost.

Year	Investment, M€	Maintenance, M€	MEA, M€	Electricity, M€	Revenues		Total, M€	Present value, M€
					District heat, M€	CO2, M€		
2015	177						177	168,6
2016		3,54	5,7	13,7	20,6	-24,7	18,9	17,1
2017		3,54	5,7	13,7	20,6	-24,7	18,9	16,3
2018		3,54	5,7	13,7	20,6	-24,7	18,9	15,5
2019		3,54	5,7	13,7	20,6	-24,7	18,9	14,8
2020		3,54	5,7	13,7	20,6	-24,7	18,9	14,1
2021		3,54	5,7	13,7	20,6	-24,7	18,9	13,4
2022		3,54	5,7	13,7	20,6	-24,7	18,9	12,8
2023		3,54	5,7	13,7	20,6	-24,7	18,9	12,2
2024		3,54	5,7	13,7	20,6	-24,7	18,9	11,6
2025		3,54	5,7	13,7	20,6	-24,7	18,9	11,0
2026		3,54	5,7	13,7	20,6	-24,7	18,9	10,5
2027		3,54	5,7	13,7	20,6	-24,7	18,9	10,0
2028		3,54	5,7	13,7	20,6	-24,7	18,9	9,5
2029		3,54	5,7	13,7	20,6	-24,7	18,9	9,1
2030		3,54	5,7	13,7	20,6	-24,7	18,9	8,6
2031		3,54	5,7	13,7	20,6	-24,7	18,9	8,2
2032		3,54	5,7	13,7	20,6	-24,7	18,9	7,8
2033		3,54	5,7	13,7	20,6	-24,7	18,9	7,5
2034		3,54	5,7	13,7	20,6	-24,7	18,9	7,1
2035		3,54	5,7	13,7	20,6	-24,7	18,9	6,8
2036		3,54	5,7	13,7	20,6	-24,7	18,9	6,5
2037		3,54	5,7	13,7	20,6	-24,7	18,9	6,1
2038		3,54	5,7	13,7	20,6	-24,7	18,9	5,9
2039		3,54	5,7	13,7	20,6	-24,7	18,9	5,6
2040		3,54	5,7	13,7	20,6	-24,7	18,9	5,3
							648,8586	421,9

The margin of error for these cost estimates is quite large, so it is necessary to conduct more detailed calculations before making any decision about whether to invest in CCS or not. The calculations presented here are only to give an impression of the possible costs involved in CCS.

For this investment to be economically feasible, CO₂ price should be over 57 €/tCO₂. In the calculations presented in the Table 9, the CO₂ price was estimated to be 25 €/t for the whole plant operation time.

The carbon dioxide transportation and storage cause extra costs that are not calculated in this thesis.

8 CONCLUSIONS

As shown in the previous chapters, adding carbon capture to an existing power plant causes a significant energy penalty to both heat and power generation. Naturally, the energy penalty also has a financial impact. For carbon capture and storage to become a viable option for large scale green house gas emission reduction also financially, the CO₂ emission price will have to rise significantly from the present level.

According to calculations presented previously, both heat and power generation would decrease significantly as a result of adding carbon capture to Vuosaari B. This would increase the use of other fossil fuels, such as coal and oil, in other power plants in Helsinki, due to the fact that especially district heat demand of the users has to be met. It is also an option to study the possibility of raising the fuel power of VuB. Then, the thermal and electrical power would not change and compensatory power generation would not be necessary. In this case, the consumption of natural gas would naturally increase in Vuosaari.

The most important reasons for the significant drop in overall efficiency are fairly obvious: At present, the CCS process is inefficient and energy consuming. Additionally, Vuosaari B is not designed for carbon capture retrofit. The options for steam extraction for the stripper reboiler are limited due to inadequate low pressure steam flow. The only found option was to extract the superheated steam before the intermediate pressure turbine which decreases both electrical and heat efficiency significantly. For example, steam extraction from the low-pressure steam header from the heat recovery boiler (steam not superheated) is not possible due to inadequate LP steam flow. During writing this thesis, no better way to integrate a carbon capture unit into the existing power plant was discovered.

It has been discovered that in coal-fired power plants the thermal power can be even higher after CCS retrofit than before. According to simulations performed for this thesis, the same phenomenon does not concern natural gas-fired CCGT power plants. On the contrary, thermal power decreases even more radically than electrical power. A rather small part of the heat delivered to the reboiler can be later recovered and utilized as district heat. Therefore, it is important to develop solutions for heat loss

minimization and more efficient heat recovery from the carbon capture unit. Of the heat consumption of the desorber, approximately 50 % is used to break the chemical bond between the absorbent and CO₂. The rest is used to the supply of sensible heat for the temperature cycling and heat losses from the system. The heat losses consist of both convective and radiation losses as well as evaporation losses for the absorbent and water from the stripper.

The results are heavily influenced by the heat demand of the stripper of the carbon capture unit. According to references, it is estimated to be 3-5 MJ/kgCO₂. In this thesis, the value 3.8 MJ/kgCO₂ was chosen for calculations. Higher or lower values have an effect on the overall efficiency and on the profitability of the power plant. Therefore, CCS technology related research should focus on cutting the energy penalty caused by carbon capture and on process integration.

Long transportation distances to potential storage locations make Finland quite unfavourable location for CCS. The nearest known storage sites are located in the southern Baltic Sea and in the North Sea. Long distances make transportation via a pipeline virtually impossible, and currently ship transportation is considered the only viable option. Therefore, it might be reasonable to assess, whether it would be better in this phase of development to invest in CCS in countries with shorter transportation distances. In the future, development in the industrial use of captured carbon dioxide could make CCS more profitable in Finland.

Before making decisions on CCS investments, the real overall greenhouse gas emissions of the capture chain from the power plant to the possible storage location should be studied carefully. When analyzing the results, it is important to remember that a tonne carbon dioxide stored is not the same as a tonne carbon dioxide avoided. While the emissions are decreased by the carbon capture unit, additional emissions are created by the tankers used for CO₂ transportation, storage equipment and additional fuel (possibly coal or oil) use in Helsinki to cover the heat demand.

Flue gas recycling is an option for CCS in combined cycle gas turbine power plants. Replacing a fraction of the inlet-air by recycled flue gas increases CO₂ concentrations, making high levels of capture easier. Flue gas recycling can also reduce capital costs when capture unit processes smaller gas flows. This is an option that should also be considered if planning carbon capture for VuB.

In addition to evaluating costs and greenhouse gas reduction potential, it is also recommended to include human health and environmental impacts on the estimates.

However, it should be noted that these results are merely indicative. More extensive and accurate calculations are necessary before making possible investment decisions. Since there has been hardly any research on integrating carbon capture units on existing CHP CCGT power plants, it is probable that in future more efficient solutions for heat integration and prevention of heat losses will be developed. It is also possible that carbon capture technologies more suitable for VuB type of power plant than chemical absorption with MEA are developed in the future.

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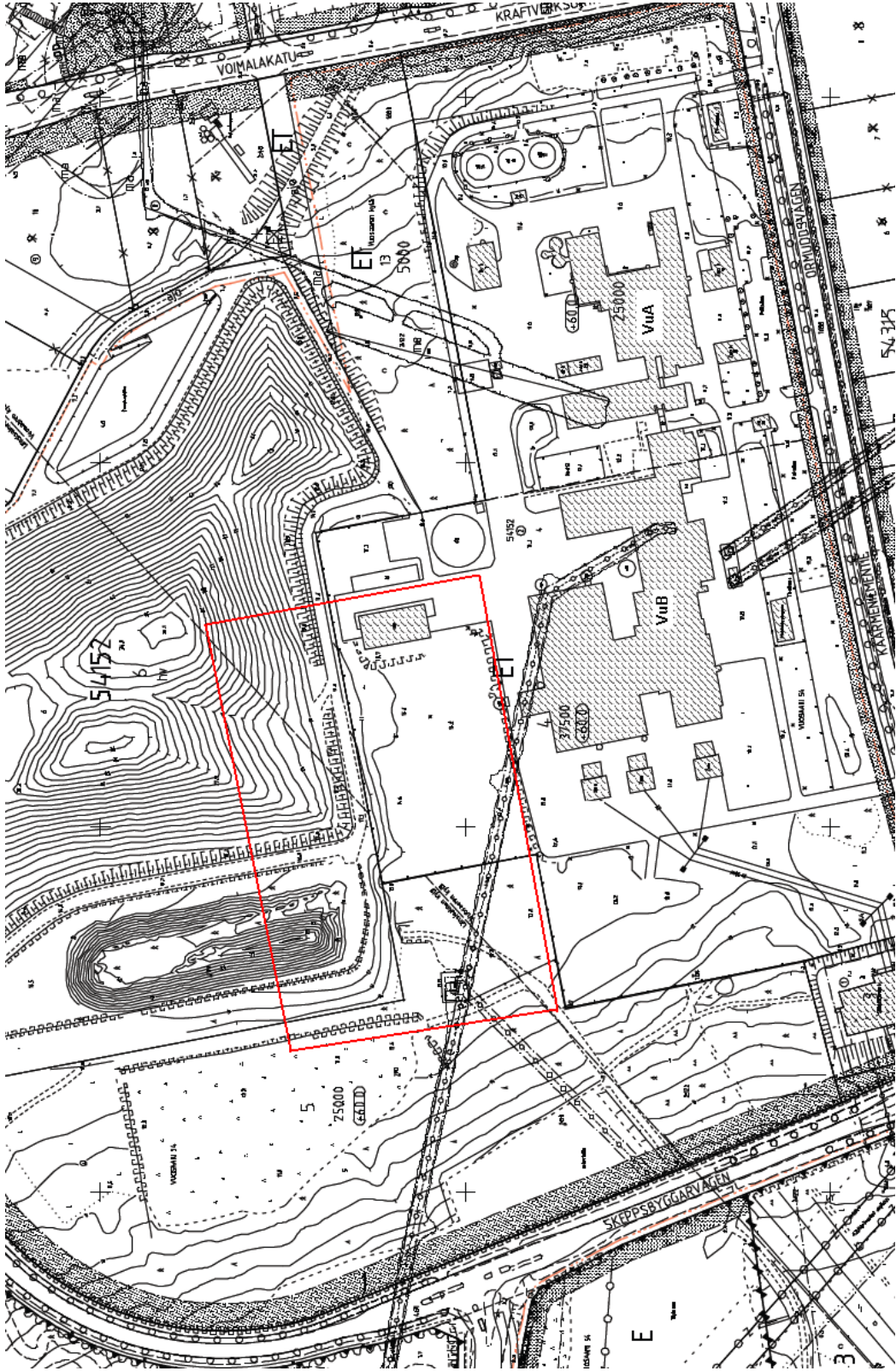
APPENDICES

Appendix A: Space requirement of CCS unit for Vuosaari B. Map: (Helsingin kaupungin kiinteistöviraston kaupunkimittausosasto, 2007)

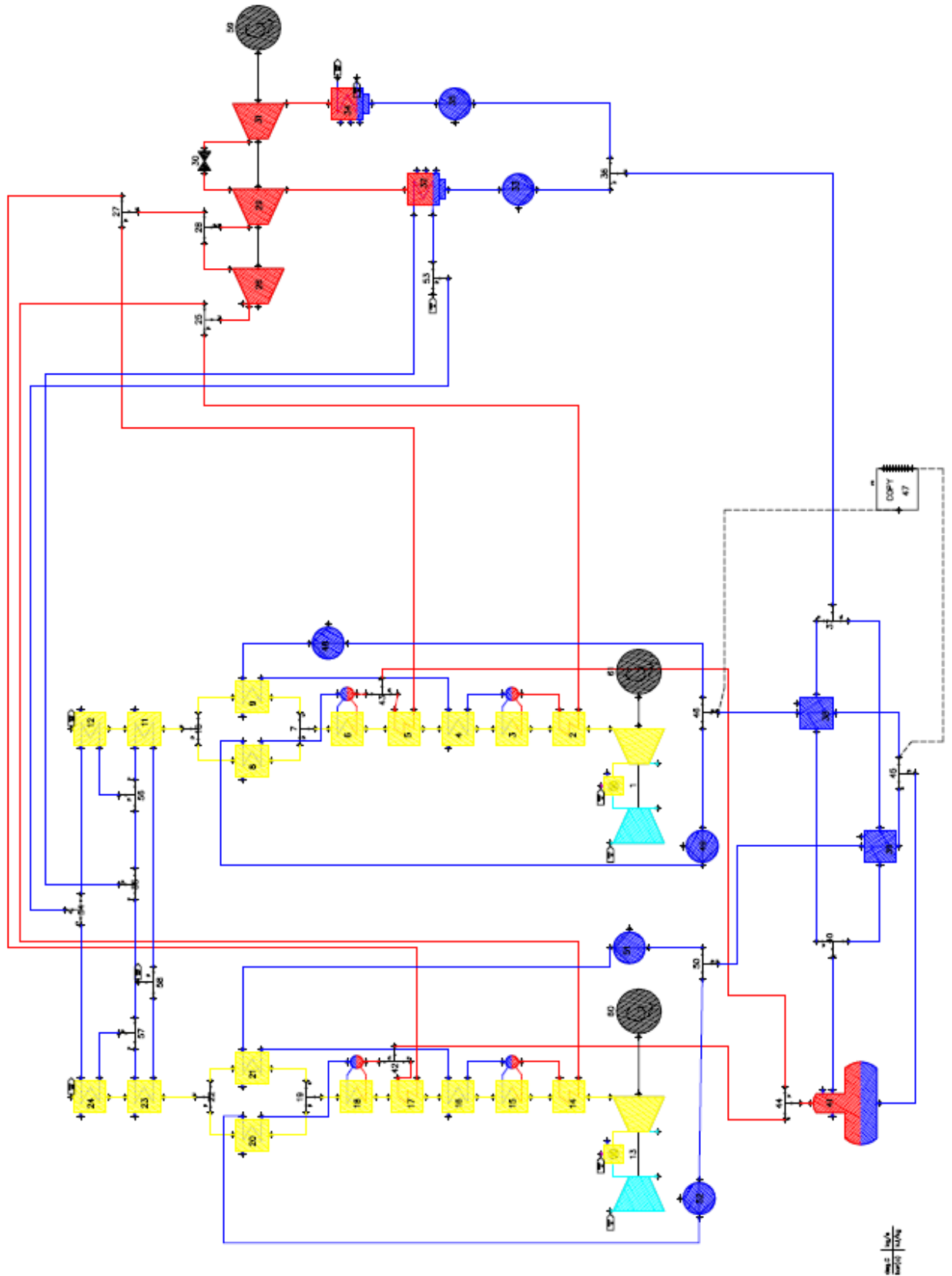
Appendix B: Vuosaari B simulation model (made with Prosim)

Appendix C: Carbon capture unit

APPENDIX A



APPENDIX B



APPENDIX C

