THE USE OF INDIRECT BIOMASS CO-FIRING TO TRANSFORM COAL-FIRED POWER PLANTS INTO RENEWABLE JET FUEL PRODUCTION FACILITIES

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- Roeland Menger
Amsterdam, February 2016

Executive summary

In this research the techno-economic feasibility of gradually transforming coal-fired power plants into renewable jet fuel (RJF) production facilities is investigated. Currently, Greenfield projects on producing RJF through biomass gasification with a Fischer-Tropsch synthesis add-on are proven not to be economically feasible without green allowances or subsidies. On the other hand, coal-fired power plants are on the verge of being mothballed on a large scale, due to environmental regulations accelerated by the UNFCCC COP-21 Paris outcomes, leaving many useful assets stranded. Furthermore, many of these plants will not be amortized at the moment that they are forced to close down, leaving a large budget deficit for the utility companies. To cover both these issues, the proposed solution in this research is to first extend the lifetime of the coal-power plant by introducing indirect biomass co-firing through gasification, after which in the future the coal boiler will be decommissioned and a Fischer-Tropsch synthesis add-on will be installed. This solution cuts both ways, since it first increases the revenues by extending the amortization of the coal-power plant (by making it more sustainable), and later decreases the costs of RJF production compared to Greenfield plants since it can make use of the existing infrastructure and assets available at the coal-power plant.

In this research two case studies are created based on multiple suitability parameters, and in a new model the techno-economic feasibility of the proposed transformation is calculated. These suitability parameters consisted of three main parameters, namely the type of gasification system, the type of feedstock and the geographical region. Based on these parameters, a shortlist of four differentiated potential supply-chain configurations in Europe is composed. Matching coal-power plants to these configurations are investigated and the 2 most promising supply-chain configurations in combination with an existing coal-power plant are selected as case studies. These case studies therefore form archetypes for other similar coal-fired power plants to introduce the same gradual transformation.

The selected case studies are the 23 year-old RWE Amer 9 coal-power plant in the Netherlands and the currently mothballed DONG Energy Asnæs 5 coal-power plant in Denmark. For the Amer 9 case study an Entrained Flow gasification system that operates on torrefied wood chips was chosen, while in the Asnæs 5 case study a pressurized Circulating Fluidized Bed gasification system with fresh woody biomass was selected. Both case studies are compared to each other on their techno-economic performance as well as benchmarked to Greenfield cases with the same feedstock – gasification technology combination.

The main benefits for a Brownfield project like a repurposed coal-fired power plant versus a Greenfield project is the reduction in CAPEX and Fixed Capital Investments (FCI), since assets and utilities like a steam turbine, infrastructure and sometimes even feedstock storage are already in place. Additional benefits for gradually transforming coal-power plants is the extension of the operational lifetime of the plant and the opportunity of a phased transition, making the investment costs in a Fischer-Tropsch (FT) add-on lower, since it is discounted to the future expenditures.

The results show that both case studies have a negative Net Present Value (NPV), which means that they do not form an economic feasible business case. The Amer 9 case study yielded a negative NPV of -1014 million euro, while the Asnæs 5 case study performed much better with a negative NPV of -595 million euro, mainly due to lower biomass feedstock costs, the use of an available heating district for residual heat, and lower investment costs for the gasification system in this case. These results show an advantage over the Greenfield cases, which yielded a negative NPV of -1263 million euro for a Greenfield case based on the feedstock and technology used in the Amer 9 case, and -675 million euro for a Greenfield case based on the feedstock and technology used in the Asnæs 5 case. This represents a cost reduction for Brownfield projects of almost 20% in the case an Entrained Flow (EF) gasifier is selected, and almost 12% in the case a Circulating Fluidized Bed gasifier (CFB) is selected. These reductions are mainly caused by the reductions in CAPEX and the possibility to discount the costs of a future investment in the FT synthesis add-on. Because of the use of existing assets the CAPEX and FCI combined are 30 million euro lower in the Asnæs 5 case compared to the CFB Greenfield case, while 121 million euro lower in the Amer 9 case compared to the EF Greenfield case. Incorporating that the future investment in the FT add-on can be discounted even widens this gap to 104 million euro in the Asnæs 5 case and 218 million euro in the Amer 9 case compared to the respective Greenfield cases. In this reduction the additional costs of decommissioning the coal boiler and surrounding utilities are already incorporated.

To sum up, this research shows that, although the NPV is still negative, producing RJF through biomass gasification with Fischer-Tropsch synthesis is economically more feasible in a gradually transformed coal-power plant than in a Greenfield project. This is based on cases without any subsidies, neither on the renewable electricity produced nor on the RJF produced. With the Dutch SDE+ subsidy on biomass co-firing of 61 €/MWh produced electricity incorporated, the RJF price still needs to be more than 2 times higher than the current kerosene price of 480 €/ton (based on December 2014 levels) in the Asnæs 5 case (i.e. 1072 €/ton RJF) and even more than 3,5 times higher in the Amer 9 case. The Greenfield cases yield in this scenario a quite similar result as their Brownfield counterparts, but are more sensitive to a higher RJF price. When only a subsidy on RJF is introduced, the Greenfield cases show better results than the gradually transformed Brownfield cases. The best performing case is in this scenario the Greenfield CFB case, which is competitive at prices of 1509 €/ton RJF. This is explained by the high impact of RJF revenues and low impact of renewable electricity subsidies on the business case in the Greenfield projects, while in the retrofitted coal-fired power plant cases this is the other way around. This also indicates that with high oil prices or a high subsidy on RJF it still is economically more feasible to transform coal-power plants than to start a Greenfield project, however the transformation should in this case not be gradual but instantly.

Furthermore, in general it can be noted that a CFB gasification system with woody biomass feedstock forms an economically more feasible case than an EF gasification system with torrefied wood chips as feedstock, due to the high feedstock prices.

In the light of the recent events, where not only older coal-power plants are proposed to be mothballed, but also newly built coal-power plants are proposed to be phased out in the near future (e.g. the RWE Eemshaven coal-power plant that was taken into operation in 2015), the gradual transformation does form an interesting business case. Although repurposing old coal-fired power plants yields a negative NPV, repurposing newly built coal-power plants could be less expensive than mothballing these. Since this forced closed down must be expensed on other incomes, such as a compensation or reimbursement from the government, additional expenditures for mothballing are expected. In these cases, a gradual transformation to a RJF production facility could be less expensive than the required compensation by the utilities for shutting the plant down. In an additional calculation the newly built RWE Eemshaven plant was proposed to be transformed to a RJF production facility. In this case, the Amer 9 case study conditions for the transformation were assumed since the logistics and geographical region are quite similar. The results show that a required yearly subsidy (as feed-in tariff for renewable electricity or as a premium on the RJF that is produced) of 122,1 million euro for 15 years is necessary in this case to become break-even. This is approximately a 40% reduction in government spending versus the 3 billion euro claim by RWE for mothballing the plant.

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1. Introduction

The RENJET project is a collaboration of amongst others KLM, SkyNRG, Climate-KIC and Utrecht University, which aims to accelerate the development of sustainable biofuel supply chains and flight operations.

This thesis, embedded in this project, aims to investigate the possibilities and feasibility of gradually transforming coal-fired power plants into renewable jet fuel production facilities, by the use of indirect co-firing (gasification) and a Fischer-Tropsch synthesis add-on.

1.1. Societal background

The world currently faces a climate change that is caused by human activities. This global warming can be mainly attributed to increasing man-made CO_2 emissions (*IPCC, 2103*). It is stated by the *IPCC (2013)* that "continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system." Therefore, limiting climate change requires a substantial and sustainable reduction of all greenhouse gas emissions, and particularly a reduction in man-made CO_2 emissions.

The total anthropogenic greenhouse gas emissions in the world counted up to 49 Gt of CO_2 equivalent in 2010 (*IPCC, 2013*). Of this total, 25% is attributed to the electricity and heat production sector, and 14% to the transport sector (*IPCC, 2013*). This means that these industries together account for almost 40% of the direct man-made greenhouse gas emissions. Both sectors will need to shift towards renewable energy resources to reduce their greenhouse gas emissions.

In this thesis, these two industries are of specific interest. A hypothetical solution of gradually transforming coal-fired power plants into renewable jet fuel production facilities is tested to overcome both the problem in the coal-fired power production industry as in the aviation industry. Both sides are discussed below in more detail.

1.2. Problem definition

1.2.1. Coal-fired power plants

Coal-fired power plants are accountable for 40% of the total electricity production in the world, while it has the most intensive CO_2 emission per kWh produced electricity (*Foster et al., 2014*). Therefore, coal-fired power plants are responsible for more than 70% of the energy sector greenhouse gas emissions (*Foster et al., 2014*).

Due to environmental regulations and the energy transition it is expected that the amount of coal-fired power plants in operation will decrease in the coming years (*Parkinson, 2015*). Especially in Europe and the United States of America, this trend is already visible. Figure 1 is adapted from the *U.S. Energy Information Administration (2012)*, and clearly shows the expected increase in the projected retirements of coal-fired power plants in the United States. Also in Germany a recent announcement was made that a number of coal-fired power plants with a combined capacity of 2.7 gigawatts will be shut down in short notice in order to reach its ambitious climate goals by 2020 (*Nienaber & Wacket, 2015*). Moreover, in the Netherlands the House of Representatives recently accepted a resolution to close all the existing coal-fired power plants in the Netherlands at a reasonable term (*Verlaan, 2015)*. The pace at which these plants are being closed will be of crucial importance, especially to the utilities (GDF Suez, Eon, RWE) which have recently built three new plants with a combined installed capacity of 3470 MW. The Dutch Financial Times quotes these utilities will claim an amount of around 6 Billion Euro if they are forced to close these new power plants in short term (*Koot, 2016*).

The expectation is that after the successful UN Climate Change Conference in Paris (COP21) many other European countries will follow a similar path as the Netherlands is currently taking. Although there is not a statement that coal-fired power plants should be phased out, the conference has increased awareness about the problem of the pollution of coal and the urgency of a quick shift to cleaner energy. The post-COP21 momentum creates a political opportunity to phase-out coal and increase the deployment of clean energy projects (*Kaye, 2015*).

Additionally, the decline of coal-fired power plants is enforced due to other non-climate change related issues, such as an internal overcapacity of the electricity market (e.g. in Denmark) and an ageing plant capacity (e.g. in the United Kingdom) (*IEA, 2014*). The Institute for Energy Economics and Financial Analysis (IEEFA) summarized the challenges and rationale to abandon coal projects after the COP-21 conference as "Declining demand, excess supply, under-utilized coal-related rail and port infrastructure, relentless cost down initiatives, excessive financial leverage, asset write-downs and unprecedented stranded assets shareholder wealth destruction" (*Kaye, 2015*).

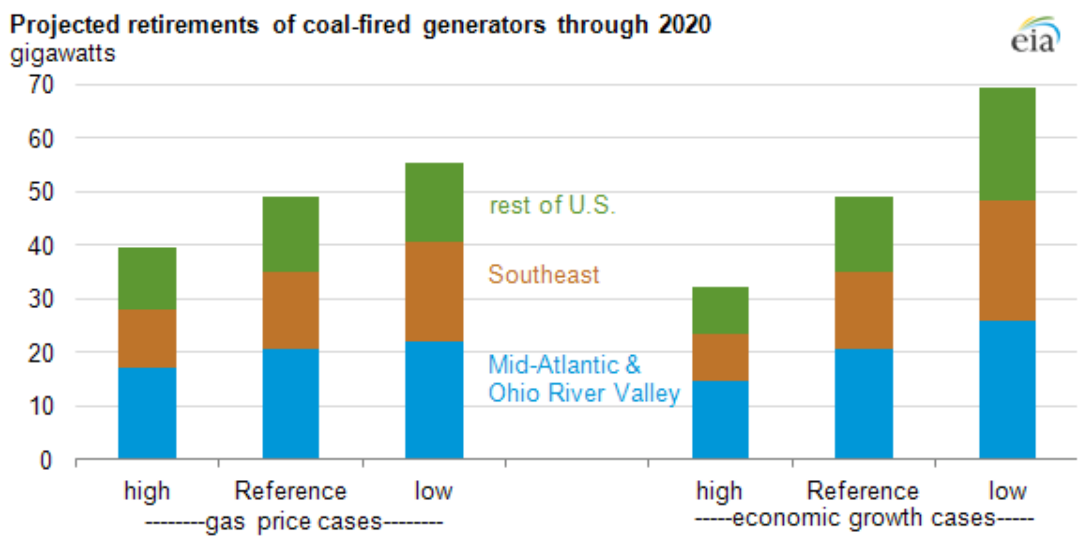

Figure 1: Projected retirements of coal-fired power plants through 2020 (EIA, 2012).

On the other hand, base load capacity is required in an energy system with a high amount of intermittent energy production, and currently coal-power plants still provide this base-load in most of the European countries. To reduce its carbon footprint and earn a license to operate, the coal power sector is inclined to investigate alternative production strategies, such as carbon capture and storage (CCS) or the use of biomass to complement or replace coal as a feedstock. CCS is often mentioned as a possible option, but due to its high CAPEX, high OPEX and high-energy intensity, it is expected to take years before CCS will make its entrance to the commercial mainstream market (*Basu et al., 2010*). Therefore, CCS is considered as a plausible option for the long term to come to zero emission power plants, but not a suitable solution for most of the current issues.

On the other hand, biomass co-firing represents a more attractive near term option, since it is a well-proven technology, which requires minimal modifications and moderate investments (*Basu et al., 2010*). This is endorsed by *Al-Mansour et al. (2010)*, who indicates biomass co-firing as a near-term, low-risk and low-cost sustainable energy development.

1.2.2. Aviation and the transport sector

A similar search for renewable energy resources implementation, as seen for coal-fired power plants, accounts for the aviation industry. The aviation sector produces the highest CO_2 emissions per passenger per travelled kilometer (*Allianz, 2010*). Globally, the aviation sector accounts for 2% of the total man-made CO_2 emissions. This accounts to a total of more than 34 billion ton of CO_2 each year (*Güell et al., 2012*). Since the aviation sector is one of the fastest growing transport sectors worldwide with an expected growth of 5% annually up to 2050, there is a need for alternative and cleaner aviation fuel (*Zschocke et al., 2013*). However, where our society, including the road transport sector, is expected to increase its electrification and corresponding share of renewable energy by wind turbines and solar panels, flying on electricity is not yet feasible (*Atherton, 2015*). Therefore, other solutions should be introduced to reduce the carbon footprint of the aviation sector. The aim of the aviation industry is to reduce the net carbon emissions by 50% in 2050 relative to the 2005 levels, and stabilize the net carbon emissions by 2020 through carbon-neutral growth (*ATAG, 2012)*. Figure 2 gives an indication on where ATAG (2012) suggests these reductions can be achieved.

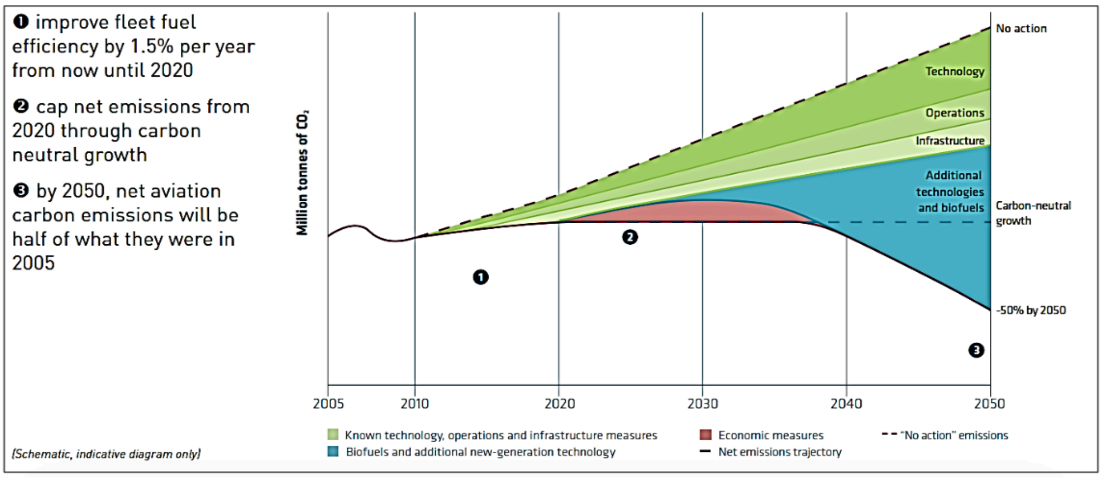

Figure 2: Projected reduction of CO_2 emissions in the aviation sector (ATAG, 2012).

Increasing the efficiency of the jet engines, optimizing the infrastructure and the operations should bridge the gap towards the 2020 goal of carbon-neutral growth. But to halve net aviation carbon emissions in 2050 relative to 2005, it is necessary to introduce renewable jet fuel (RJF), a full drop-in alternative which does not require any modifications to the jet engines, existing infrastructure or other equipment (*Zschocke et al., 2013; Güell et al., 2012; ATAG, 2012*).

There are many different pathways possible to obtain RJF. In their recent benchmark study to synthetic biofuels for aviation, *Güell et al.* (*2012*) identify three technologies as the most promising and suitable technological pathways to convert biomass resources to aviation fuel. This study is "based on data collection provided through in-depth questionnaires by the most relevant stakeholders involved currently in the product of renewable aviation fuel in conjunction with publically available literature (articles, studies, press releases and presentations)" (*Güell et al., 2012*). The three technological pathways are:

1. Hydroprocessed Esters and Fatty Acids (HEFA);
2. Fischer-Tropsch (FT);
3. Alcohol-to-Jet (ATJ).

All three can be categorized to a different technology method: The Hydroprocessed Esters and Fatty Acids is a form of an oleochemical process, Fischer-Tropsch is a form of a thermochemical process and Alcohol-to-Jet is a form of an "hybrid platform", which means that it combines elements of the other methods (*Karatzos et al., 2014*).

Unfortunately, not one of the three processes is currently the silver bullet to renewable jet fuel, since they all face disadvantages. It is expected that the oleochemical processes will not be able to experience a significant expansion, since they are limited by the cost, availability and sustainability of feedstock, partly due to the "food versus fuels" concerns and related debate (*Karatzos et al., 2014*). However, oleochemical processes do have a relatively low technological risk and low capital expenditures, making this method very suitable for a smaller scale. The thermochemical processes, on the other hand, have high capital expenditures and relatively larger technology risks, but can make use of more abundant, non-food, feedstock like lignocellulosic biomass or waste. This can be an indication that thermochemical processes can form a better business case over time, if economies of scale are achieved and the CAPEX lowers due to learning effects (*Hannula et al., 2013 ; Knoope et al. 2013*). Therefore, it is expected that in the near – to midterm future thermochemical technologies will be accountable for a major part of the "drop-in" biofuel capacity growth (*Karatzos et al., 2014*). Furthermore, *Güell et al.* (*2012*) earmarked the Fischer-Tropsch process as a promising process to produce RJF due to the high carbon conversions and the high flexibility to the feed material. However, there is a major downside: Currently none of these processes are proven to be cost-competitive to conventional kerosene yet. The main challenge for the economic feasibility of a gasification + FT process is the high CAPEX of the complete system (sometimes up to 50% of the total expenditures) due to its required large scale (*Güell et al., 2012*). Additionally, the biomass feedstock and logistics form one of the main cost components in it as well (*Wu, 2014*).

1.3. Proposed solution

The hypothesis of this thesis is that combining the two challenges can form an interesting new business case. Case studies show that it is economically most feasible to locate a Fischer-Tropsch RJF production facility at a location where there is a combined heat and power (CHP) plant available and with solid biomass logistics in place or potential (*Ekbom et al., 2009*). The synergies of having a steam turbine, heating district and biomass infrastructure already in place improves the business case compared to a Greenfield Fischer-Tropsch biomass to liquids plant. The hypothesis of this thesis argues that in a Brownfield project of repurposing coal-fired power plants and gradually transforming those to RJF production facilities, all these benefits are in place. Furthermore, by extending the lifetime of the coal-fired power plant –which would otherwise be taken out of production due to environmental regulations– the added profitability of this plant will contribute to the overall economic feasibility of RJF production.

1.4. Research gap

To date, research has primarily focused on the aforementioned phases separately, but never took a combined approach into account.

Al-Mansour et al. (2010), *Basu et al. (2010)* and *Hansson et al. (2009)* have focused on the co-firing of biomass in coal-fired power plants in general. The main findings on co-firing are very positive, especially in the European Union. *Hansson et al. (2009)* calculated that the estimated co-firing potential in the EU-27 countries could amount up to 35% of the goal for the electricity generation of renewable energy resources. In terms of economic viability, *Basu et al. (2010)* notice that the internal rate of return (IRR) of especially more CAPEX intensive systems, like indirect co-firing, depends strongly on the capacity factor of the plant. The downside of these above-mentioned studies is that they all solely focus on co-firing for electricity generation, and do not take other output possibilities into account. The add-on of a Fischer-Tropsch process has therefore not been evaluated in these.

Studies by, amongst others, *Ekbom et al. (2009), Güell et al. (2012), Swanson et al. (2010), Karatzos et al. (2014), Hannula et al., (2013)* and *Yamashita et al. (2004)* have explored the techno-economic feasibility of producing FT fuels. They conclude that currently the cost-effectiveness is low. The main bottleneck in the cost-effectiveness of gasification systems that deliver a suitable quality syngas for liquid fuels is largely attributed to the high CAPEX for these systems and the cost of feedstock (and correlating feedstock infrastructure). Hence, economies of scale are required to make this technology cost-competitive.

Research on different cost reduction possibilities for biomass to liquids (BtL) is performed as well. *Karatzos et al. (2014)* suggest lowering the capital costs of the processes by leveraging existing process units available in petroleum refineries.

Haarlemmer et al. (2012) endorse this finding and state that the integration in an industrial site like a refinery can lead to 20% cost reduction in both the CAPEX as the production costs. Next to this, the study of *Haarlemmer et al. (2012)* show a couple of other ways to decrease the costs and increase the economic feasibility of gasification systems, such as the possibility of injecting raw biomass (i.e. without pre-treatment) into the gasifier. This will decrease the capital expenditures and the production costs, but is far from being technically confirmed and therefore a possible option in the future (*Haarlemmer et al., 2012*).

The elaborate study of *Swanson et al. (2010)* shows that the efficiency of a FT plant highly depends on the type of gasifier, the gas separation unit, the feed processing and the FT plant selection. This efficiency can mainly be improved through process integration (*Swanson et al., 2010*). *Meerman et al. (2013a ; 2013b)* and *Knoope et al. (2013)* both show in different studies the projected future performance and costs of FT production systems. They take both coal-FT processes as biomass-FT processes into account and focus on processes with and without CCS. Their projections on the production costs of future FT processes are given in figure 3.

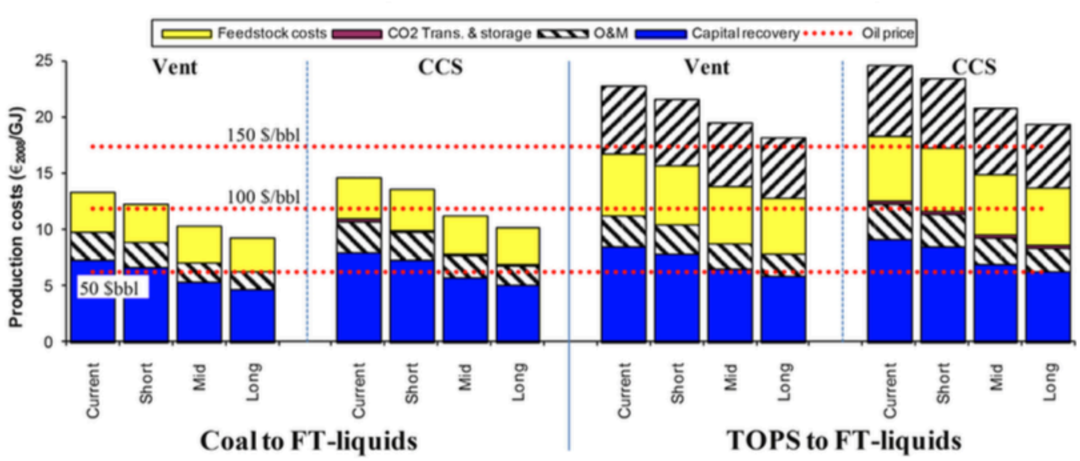

Figure 3: Coal to FT-liquids and biomass to FT-liquids production costs. TOPS stands for torrefied biomass. The lighter upper part of the feedstock bar is the addition in production costs when using the high value for the TOPS price (adapted from Meerman et al. 2013a&b).

The expected cost reduction in FT processes can mainly be attributed to newly available technologies, an increase in efficiency of the process, learning effects due to an increase in installations, benefits due to economies of scale and a possible decrease in the feedstock costs (*Meerman et al., 2013a&b* ; *Knoope et al., 2013 ; Van Vliet et al. 2009*). The largest reduction in production costs is expected in the short- to midterm, since in this time frame new technologies are expected to enter the market (*Meerman et al., 2013a&b*). These new technologies are expected to decrease the capital expenditures, especially regarding the gas cleaning process and in the oxygen production section (*Meerman et al., 2013a&b*). Therefore, in the long term, biomass to liquids could become competitive to oil liquids, depending on, amongst others, the price of oil. *Knoope et al. (2013)* show that with a CO_2 price above 48 €/t CO_2, an oil price above 87 €/bbl, and a feedstock price up to 6,3 €/GJ, biomass to liquids are economically the best alternative for biomass use. However, the current extraordinary low oil price, which is below 30 €/bbl[1], is not contributing to the cost-effectiveness of these systems, and forms a serious threat to current investments, which influences the learning curve and future cost-effectiveness.

In this thesis, the results of the different aforementioned studies are combined to investigate the viability of an integrated approach to gradually transform coal-fired power plants into renewable jet fuel production facilities. The benefits of a gradual transformation are that on the one hand the lifetime of a coal-power plant, that otherwise needs to be closed, is extended and on the other hand that the high investments in a gasification system and a Fischer-Tropsch synthesis add-on are split up over different timeframes. Additionally, the stranded assets of a (future) mothballed coal-fired power plant can in this case be reused in the renewable jet fuel production facility.

This gradual transformation is split up into two different phases:

Phase 1: Integrate indirect biomass co-firing into existing coal-fired power plants. The indirect co-firing makes use of a gasification system, which produces a synthetic gas. This syngas can be burned in the same boiler as the coal to produce electricity. This can be a first step in transforming polluting coal-fired power plants into more environmental friendly power production facilities, without having to amortize these. Biomass co-firing in existing coal-fired power plants can extend the lifetime of the power plant, and make it suitable to meet new regulations and environmental targets set by governments. Moreover, due to the existing supply infrastructure, boiler furnace and steam turbine, the extra investments for biomass co-firing are expected to be low.

Phase 2: The start of phase 2 is the moment when the coal boiler has reached its end of lifetime. At that point, the coal boiler will be decommissioned and a Fischer-Tropsch synthesis add-on can be installed at its place. The output syngas from the gasification system now forms a direct input in the FT process, which converts it to liquid fuels, heat and electricity. As it is anticipated that Fischer-Tropsch synthesis for synthetic liquid fuels will experience a cost-decline from 2020 onwards (*Karatzos et al. 2014*), a Fischer-Tropsch process add-on might become cost-competitive at the moment of its installation. Moreover, the infrastructure present at a coal-fired power plant is likely to allow for efficient feedstock logistics. So in phase 2, the gasification system together with the Fischer-Tropsch unit will produce clean electricity, FT liquid fuels (of which mainly RJF) and possibly residual heat to a heating district in the case that there is one available at the power plant location.

1.5. Research question

Following from the identified research gap and the proposed business case opportunity, the main research question of this study is:

[1] Brent Oil, Q1 2016; *http://nl.investing.com/commodities/brent-oil*

What is the short- to mid-term technical and economic feasibility of incremental development RJF production using FT synthesis by gradual transformation of existing coal-power plants before 2030?

To guide this research question, a set of sub-questions is formulated. These sub-questions also represent the different stages of the research, as discussed in the methodology section (chapter 3).

1.) Scoping supply chain configurations

- Which coal-fired power plants in the European Union are potentially available for biomass co-firing?
- What types of gasification systems and pathways produce a high-quality syngas and are suitable to be installed as biomass co-firing unit in a coal-fired power plant?
- What type of biomass feedstock is physically available on large scale for co-firing in the European Union?
- What is the expected development trajectory of gasification and Fischer-Tropsch synthesis technologies in term of scale and economic feasibility?

2.) Selecting the supply chain configurations and utilities for two case studies

- Is it technically feasible to transform a coal-fired power plant into a renewable jet fuel production facility?
- What system types form a possible pathway for coal-fired power plants to gradually transition from a coal-fired power plant into a renewable jet fuel production facility?

3.) A techno-economic analysis for the two case studies

- What is the techno-economical feasibility to gradually transform a coal-fired power plant into a renewable jet fuel production facility under given circumstances?

4.) Sensitivity analysis on the outcomes of the two case studies

- Is it currently economically viable to produce RJF through biomass co-firing, using these transformed coal-fired power plants, compared to other options like Fischer-Tropsch Greenfield projects? If not, in what scenario is it most likely to be economically viable?
- Provides the phased transition additional benefits compared to a direct transition?

The abovementioned case studies consist of studies performed on real data of existing coal-fired power plants, which can form archetypes for other coal-fired power plants throughout Europe. The selection criteria regarding the choice for the selected power plants are explained in the methodology section (chapter 3).

2. Theoretical framework and background

2.1. Techno-ecnomic analysis

In this thesis, the feasibility of the case studies was calculated by performing a techno-economic analysis. The techno-economic analysis, which is also known as a bottom-up analysis, is specifically focused on individual technologies and determines the potentials through aggregation (*Blok, 2009*). For a techno-economic analysis information on the costs is required. Techno-economic models form the basis for calculations on the technical, economic and profitable potential of projects, and are suitable for a detailed and comprehensive overview (*Blok, 2009*). It should be noted however, that these resulting potentials never imply a forecast or projection to the future, but are solely to provide information. However, it is possible to incorporate a forecast or projection into a techno-economic analysis. This should be done using different scenarios (e.g. business-as-usual) in the techno-economic model, which adds assumptions on the future behavior of the actors involved (*Blok, 2009*).

2.1.1. Techno-economic analysis breakdown

A techno-economic analysis usually consists of multiple factors. Starting at the large overview perspective, first a breakdown needs to be made into parts that can be treated individually. This breakdown needs to be as precise as possible, with every part that consists of multiple processes broken down into new parts (*Blok, 2009*). Second, technologies that are of interest for these different parts are identified and characterized. Since usually through this breakdown a large spread and associating variety of sources comes available, the main challenge here is to compile all the information into one common set of characteristics (e.g. a database). The most important information to be gathered in this process is the technical performance and information on the correlating costs (*Blok, 2009*). From this database calculations are carried out on the technical, economic and profitable potential.

2.2. Biomass co-firing

Biomass co-firing is a process where through the use of co-combustion (direct), gasification (indirect) or an additional boiler (parallel) all types of biomass and wastes are converted to electricity in a coal-fired power plant. The differences in these three main possibilities are briefly explained in more detail below.

Co-firing is considered as the most efficient way of generating power from biomass (*Basu et al., 2010*). In addition, biomass co-firing is expected to substitute coal in coal-fired power plants. Therefore it can contribute significantly to the lowering of the CO_2, SO_2 and even NO_x emissions of coal-fired power plants, while at the same time increase the share of renewable energy resources in the energy balance (*Al-Mansour et al., 2010*). In other words, regarding the EU 2020 goals and the COP21 outcomes, biomass co-firing cuts both ways.

2.2.1. Direct co-firing

Direct co-firing is a process where the biomass is burned in the same boiler furnace as the coal (figure 4.a). Depending on the setup, the coal and biomass are either pulverized using the same mills, or the biomass uses a separate mill to be pulverized. The level of integration mainly depends on the biomass fuel characteristics (*Basu et al., 2010*). Direct co-firing is the least expensive, most straightforward and most commonly applied approach, since it enables co-firing without significant investment costs (*Al-Mansour et al., 2010*).

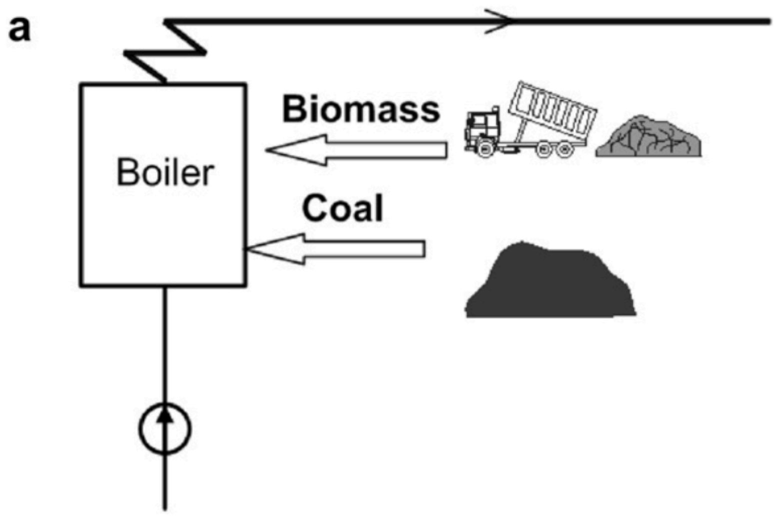

Figure 4.a: Direct biomass co-firing technology (Al-Mansour et al., 2010).

2.2.2. Indirect co-firing

Indirect or gasification co-firing is a process where the solid biomass or waste is first converted into a fuel gas through a gasification system (figure 4.b). This fuel gas is a form of synthetic gas, or syngas. The syngas is then fed to the same boiler furnace as the coal, where it is burned. This approach can offer a high degree of fuel flexibility (*Basu et al., 2010* ; *Al-Mansour et al., 2010*). The fuel gas can be cleaned before the combustion to minimize its impact on the boiler, but this may not be necessary in some cases and depends on the type of biomass. Despite the significantly higher capital investment that is required in relation to a direct co-firing process, the advantages of indirect co-firing form an attractive case for utility companies (*Al-Mansour et al., 2010*).

With regard to the purpose of gradually transforming a coal-power plant into a renewable jet fuel production facility, indirect co-firing of biomass is the only option, since this is the only configuration which includes a gasification system.

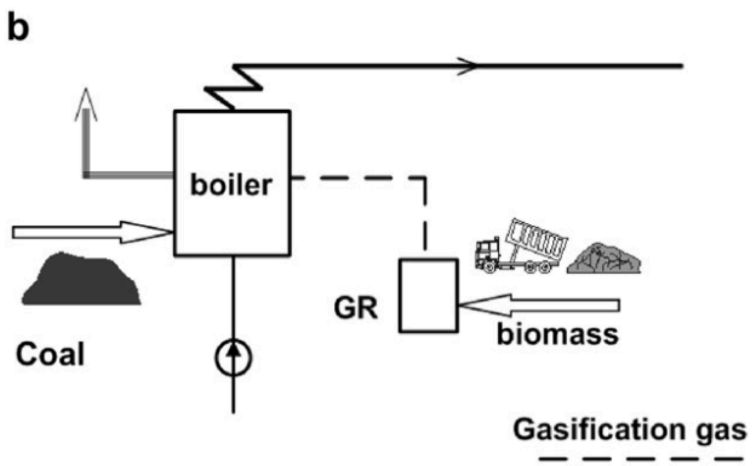

Figure 4.b: Indirect biomass co-firing technology (Al-Mansour et al., 2010).

2.2.3. Parallel co-firing

The third option is the parallel co-firing process (figure 4.c). This process is the most elaborate one, which includes the installation of a completely separate biomass boiler. In this separate boiler the biomass is burned to produce steam, which is utilized in the coal power plant steam system to produce electricity along with the steam from the coal boiler (*Al-Mansour et al., 2010*).

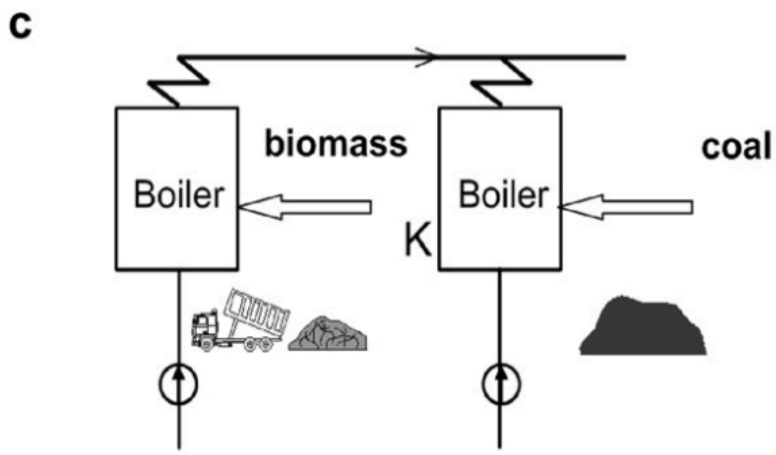

Figure 4.c: Parallel biomass co-firing technology (Al-Mansour et al., 2010).

2.3. Gasification systems

A gasification system uses solid carbonaceous materials as input and breaks this down into simple fuel gasses. These fuel gasses are called synthetic gas, or syngas, and consist of hydrogen and carbon monoxide (H_2 + CO).

2.3.1. Gasification process

Biomass gasification is the process of converting solid biomass to a synthetic gas through high temperatures and pressure, using air, oxygen or steam as a gasifying agent (*Karatzos et al., 2014*). The gasification of biomass is an endothermic reaction, which means it requires high temperatures (*Unruh et al., 2010*).

There are four main types of gasification systems suitable for transforming solid biomass to syngas, namely Fixed Bed, Fluidized Bed (Circulating and Bubbling, respectively CFB and BFB), Entrained Flow (EF) and Plasma Arc. The exact specifications of these different systems are given in Appendix A. Fixed bed gasifiers were placed out of scope, due to the limited capacity of these systems and therefore the limited operational scale that can be achieved (*E4Tech, 2009*).

The main differences between the types of gasification systems are the temperature in the gasifier and the feedstock tolerance. This latter is also the main parameter to which extend pre-treatment of the feedstock is necessary before it can enter the gasification system. In table 1, an overview is given of the feedstock tolerance per type of gasification system (*E4Tech, 2009*).

Gasifier	Size	Moisture	Composition	Other
EF	<1mm	15%	Should not change over time. Limited proportion of high-ash agricultural residues	Pre-treatment steps being used
BFB (and Dual with BFB gasifier)	<50-150mm	10-55%	Can change over time Care needed with some agricultural residues	
CFB (and Dual with CFB gasifier)	<20mm	5-60%	Can change over time Care needed with some agricultural residues	
Plasma	Not important	Not important	Not important, can change over time. Higher energy content feedstocks preferred	Used for a variety of different wastes, gate fees common

Table 1: Feedstock tolerance for each type of gasification system (copied from E4Tech, 2009).

To scope the research, first the different possibilities regarding gasification systems and processes were investigated. In a rough way it can be stated that in gasification processes three variables can be identified:

1. The type of feedstock that can be used;
2. The type of gasification system that can be used;
3. The quality of the output (syngas) that can be delivered.

These three are all interconnected and therefore different chains from feedstock to output can be identified. This thesis focused on indirect biomass co-firing and the production of renewable jet fuel. This means that only gasification systems that can use biomass or municipal solid waste (MSW) as feedstock are taken into consideration.

2.3.2. Oxygen unit and cleanup steps

With an atmospheric-blown gasification system the quality of the output syngas will not be high enough to be suitable for producing FT fuels (*Boerrigter et al. 2006*). Moreover, an oxygen-blown gasifier is a necessity to avoid nitrogen dilution of the syngas, which would increase the equipment costs and reduce the synthesis performance (*Larson et al., 2009*). However, the produced syngas from raw biomass through an oxygen-blown gasification system still needs additional cleaning steps in order to remove impurities and adjust it to FT synthesis requirements (*Unruh et al., 2010*). This cleaning process might be expanded by a water-gas shift reaction, dependent on the quality of the syngas output (*Steen et al., 2008*). This water-gas shift reaction is only necessary if the H_2/CO ratio is not adequate (i.e. below 2:1) to produce FT liquids, which is mainly the case when using an atmospheric-blown gasification system (*Hamelinck et al., 2004*). A drawback, and therefore reason why to avoid it in practice, is that the water-gas shift reaction might result in a loss of carbon yield of the liquid fuel in the overall process (*van Steen et al., 2008*). Therefore, only oxygen-blown gasification systems were taken into account in this research. A drawback on these systems is the extra investments needed in purified oxygen and an on-site oxygen-pressurizing unit, but this outweighs the drawbacks of atmospheric-blown gasification systems.

But still regarding solely oxygen-blown gasifiers, the output syngas can have different qualities, depending on the chosen feedstock, type of gasification system and the gasification temperature (*Boerrigter et al. 2006*). The undesired presence of methane, hydrocarbons and tars, in combination with the hydrogen to carbon monoxide ratio value, are the best indicators of the quality of the produced syngas (*E4Tech, 2009*). Only when the quality of the syngas is high enough it can form the input for a subsequent Fischer-Tropsch process to turn the syngas into synthetic fuels (*Güell et al., 2012*). Different aspects of the syngas determine the minimum quality of the input for an efficient FT add-on module. *Boerrigter et al. (2004)* present rule-of-thumb specifications for a Fischer-Tropsch process feed gas, which are especially of importance regarding the impurities of biomass-derived syngas. In table 2 these specifications are given.

Impurity	Removal level
$H_2S + COS + CS_2$	< 1 ppmV
NH_3 + HCN	< 1 ppmV
HCl + HBr + HF	< 10 ppbV
alkaline metals	< 10 ppbV
solids (soot, dust, ash)	essentially completely
organic compounds[a] (tars)	below dew point
- class 2[b] (hetero atoms)	*< 1 ppmV*

[a] Organic compounds include also BTX. [b] Class 2 tars comprise phenol, pyridine, and thiophene.

Table 2: Fischer-Tropsch feed gas specifications (copied from Boerrigter et al., 2004).

2.4. Fischer-Tropsch process

The Fischer-Tropsch process is a relatively old process, from the early experiments in ~1925 to multiple technologies and processes already available in ~1955 (*Schulz, 1999*). However, despite the rich history, it is currently hard to form an economically feasible biomass to liquids Fischer-Tropsch process (*van Steen et al., 2008*). One unconventional strategy that is tested in this thesis is to improve the economic feasibility by making use of existing assets. In figure 5, a simplified overview for the BtL process with gasification system and Fischer-Tropsch synthesis is given.

Figure 5: Flow sheet of the biomass to liquids via Fischer-Tropsch process (Hu, 2012).

2.4.1. FT synthesis reaction

The output syngas ($CO+H_2$) from the gasification system is the input for the Fischer-Tropsch module. In a Fischer-Tropsch synthesis one mole of carbon monoxide reacts with two moles of hydrogen in order to form paraffin straight-chain hydrocarbons (C_xH_{2x}). These long-chain hydrocarbons are called wax or FT-wax (*van Steen et al., 2008*). In the ideal scenario of this process, only minor amounts of branched and unsaturated hydrocarbons, such as 2-methyl paraffin and α-olefins, are formed (*Boerrigter et al., 2006*). The reaction in a FT synthesis process is given in equation 1.

$$CO + 2H_2 \rightarrow\ -(CH_2) - + H_2O \qquad [1.]$$

The FT synthesis reaction is an exothermic process, which takes place over specialized catalysts, such as cobalt- or iron-based catalysts, whose surface acts as an 'anchor' upon which the carbon monoxide and hydrogen adsorb (*Karatzos et al., 2014*). When the carbon monoxide is broken down, the carbon couples to the hydrogen while the oxygen leaves the system (in H_2O). This process continues with the adding of new syngas in the system, until the chain is desorbed from the catalyst and the newly formed hydrocarbon molecule leaves the system (*Karatzos et al., 2014*). Figure 6 gives a simplified representation of this process.

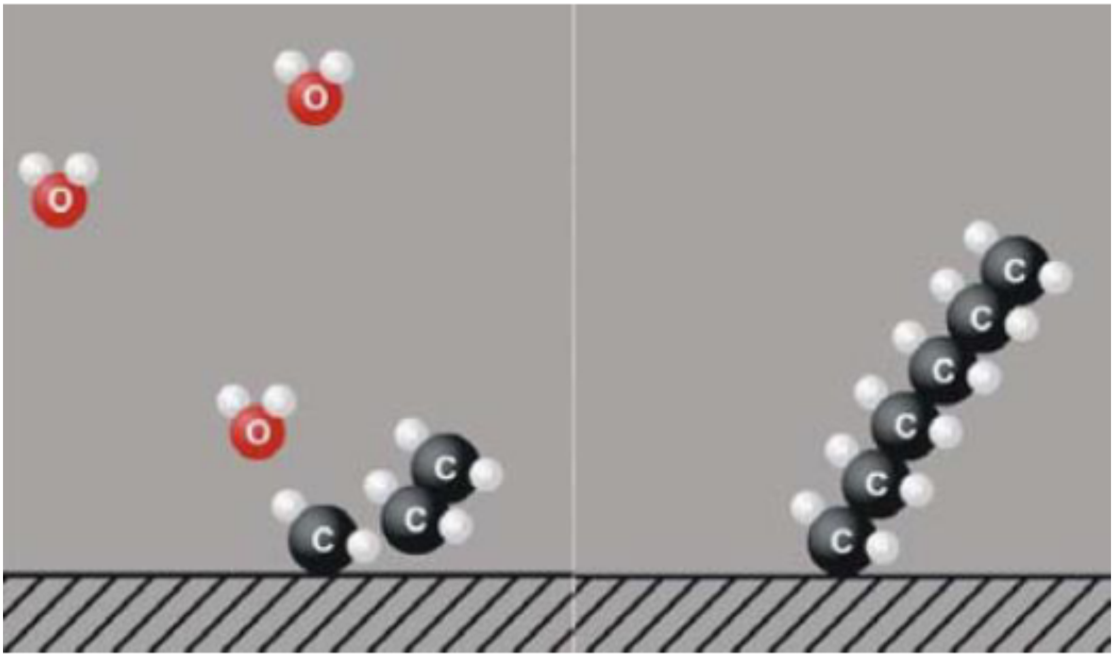

Figure 6: Simplified overview of FT catalyst process (Source: Karatzos et al., 2014)

However, in this process, undesirable side reactions can occur. The formation of these undesirable side reactions, such as Methanation, the Boudouard reaction, coke deposition, oxidation of the catalyst, or carbide formation, depends mainly on the quality of the syngas input in the FT synthesis (*Boerrigter et al., 2006*).

2.4.2. FT liquids and the hydroprocessing

The hydrocarbon output (i.e. FT liquids) is not yet suitable for production purposes or as a fuel. An upgrading step of the primary FT products is necessary in order to produce a maximum yield of high quality fuels. This is done through a hydroprocessing step, which includes hydrocracking and isomerization (*Unruh et al., 2010*). This hydroprocessing can be performed in an existing refinery or in separate hydroprocessing reactors at the FT production site (*Karatzos et al., 2014*). Locating the FT production site near an existing refinery is the most economic solution, since no separate hydroprocessing reactors need to be built and the transportation costs of the FT liquids will be low.

2.4.3. Advantages and disadvantages FT synthesis for BtL

The main advantages for gasification combined with Fischer-Tropsch processes are the wide variety of possible feedstock and the fact that the output is approved for certification as jet fuel (*Güell et al., 2012; Karatzos et al., 2014*). Next to this, Fischer-Tropsch is an already often applied process in combination with fossil feedstock and therefore can be considered as a proven technology to produce synthetic liquids from syngas (*Moholkar et al., 2012*). However, the wide spectra of potential output products from this process can endanger the business case for renewable aviation fuel, since the competing outputs could deliver a more viable business case. In addition, as aforementioned, the Fischer-Tropsch process requires a high-quality syngas as input (*Hu et al. 2012*). This makes not every gasification system suitable to be coupled to a Fischer-Tropsch process.

2.4.4. Current FT-BtL processes

Currently, the production of FT fuels from biomass is still above market prices (*Meerman et al., 2013b*). The expectation is, however, that on the long-term biomass gasification in combination with Fischer-Tropsch facilities will be profitable (*Meerman et al., 2013b*). The exact moment that FT shows to be profitable depends on multiple factors. Research from *Takeshita et al. (2008)* show a big future potential role of Fischer-Tropsch synfuels in the global energy mix. In addition, *Knoope et al. (2013)* show the expected trajectory for Fischer-Tropsch fuel development. Following these researches it can be expected that from 2025 onwards the Fischer-Tropsch synthesis to produce synthetic fuels is an economically viable process, and it will increase its market share from that moment on (*Takeshita et al., 2008 ; Knoope et al., 2013*). Figure 7 and figure 8 show this expected increase in market share in more detail for two possible scenarios. This future potential makes it an interesting process to further analyze in this thesis.

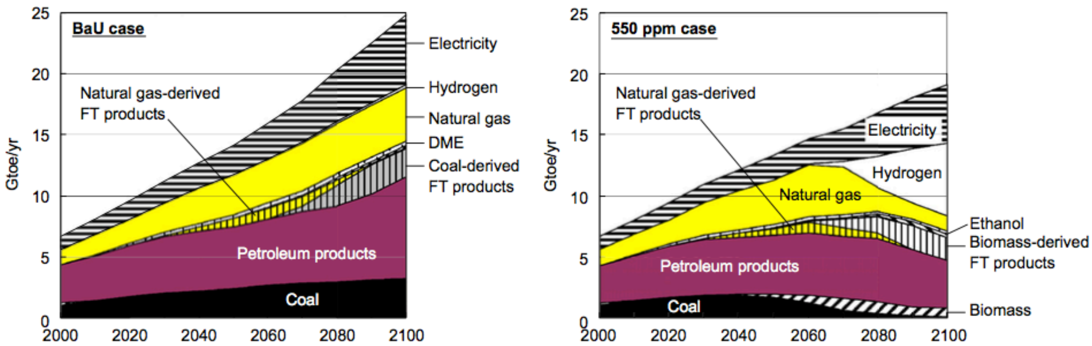

Figure 7: Global final energy consumption in a business as usual case (left) and a 550 ppm limit case (Takeshita et al., 2008).

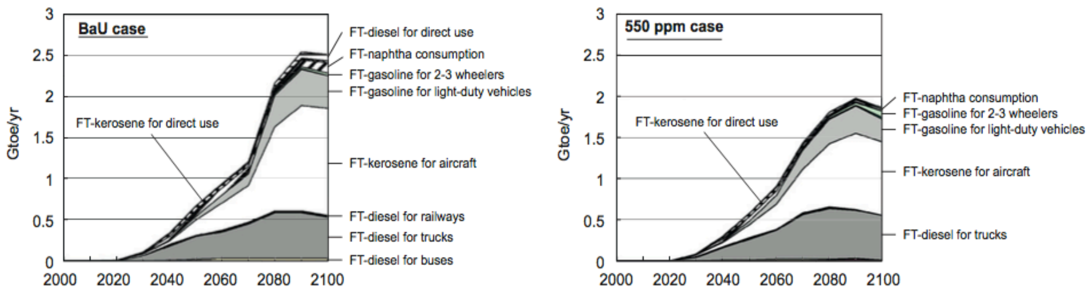

Figure 8: Global FT products consumption in a business as usual case (left) and a 550 ppm limit case (Takeshita et al., 2008).

3. Methodology

The research is structured by dividing it into four different stages, corresponding with the main themes of the sub-questions. In stage 1 a literature review was made to assess key performance indicators of the supply chain components (i.e. feedstock, gasification, coal power plant and FT synthesis). Based on these key performance indicators, 2 different supply chain configurations were identified and case studies were set-up, which could function as archetype for other coal-fired power plants. In the 3rd stage, an economic analysis was performed on the two case studies and their transition scenarios. On the outcomes of this stage sensitivity analyses were performed and a benchmark to Greenfield projects is made. In figure 9 a schematic overview of the different stages is given.

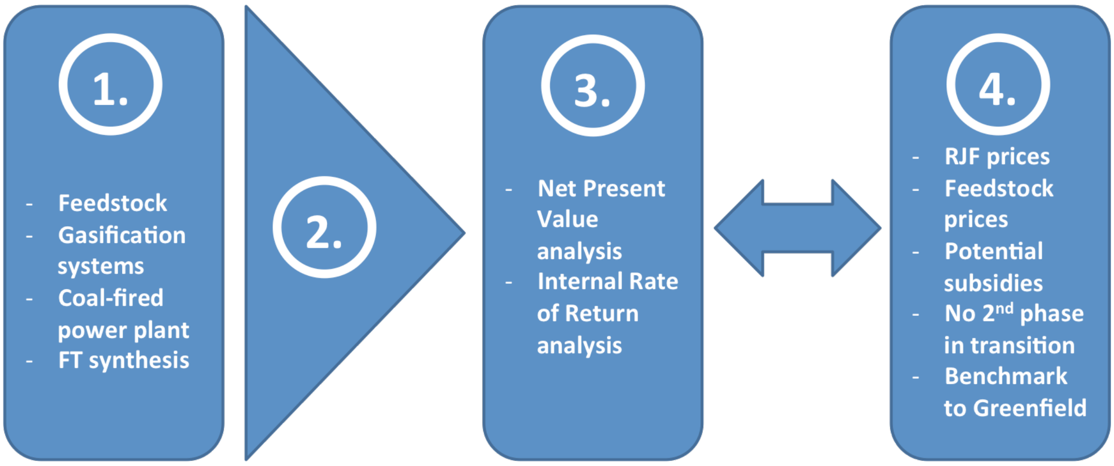

Figure 9: Schematic overview of the different stages in the research.

3.1. Scoping for case studies

The first stage of the research focused on formulating the two case studies by an extensive literature review. This creates an overview of all the possible options for indirect biomass co-firing, from feedstock to end product. The main components of the supply chain configuration are identified to scope this overview in a way that the resulting list of possible supply chain configurations are relevant for this research. The components that were essential in this process, and which are described in more detail below, are:

- Feedstock;
- Type of gasification systems and their scale;
- Available coal-fired power plants.

As a result, a list of possible supply chain configurations (from feedstock to type of gasifier and matching archetypical coal-fired power plants) is made, of which the two case studies were selected. In figure 10 a flow-chart overview is given of this process.

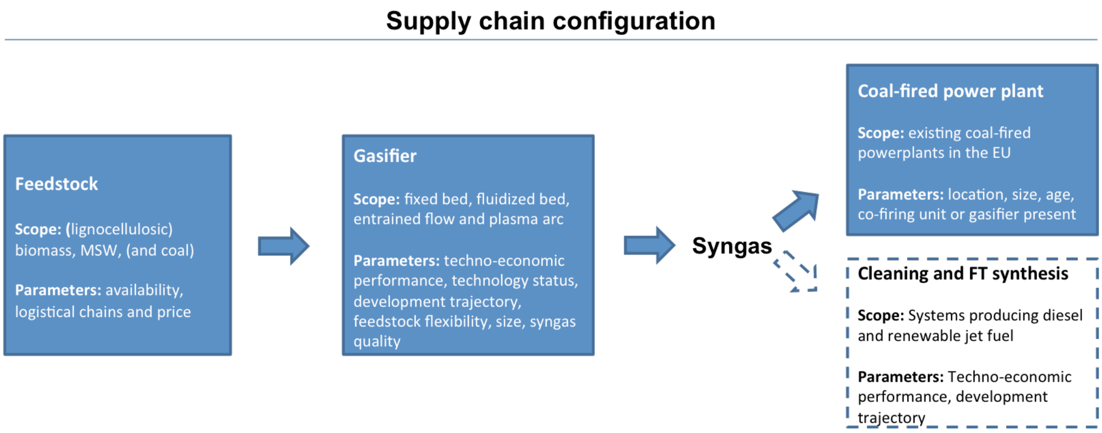

Figure 10: Supply chain configuration with the different parameters for each part.

3.1.1. Feedstock

As mentioned in the theoretical background, in the case of indirect biomass co-firing, a gasification system is set up next to the coal-fired boiler in a power plant. In this gasification system, only biogenic products such as biomass or waste should be used as feedstock in order to meet the EU biomass regulations. Therefore the feedstock was scoped these biogenic products.

Biomass can be subdivided into different categories, depending on its physical characterization and chemical composition. Particularly suitable biomass for co-firing and renewable jet fuel production is lignocellulosic biomass, because of the abundance of the available raw materials and the existing production methods of lignocellulosic biomass to biofuels (*Güell et al., 2012)*. Municipal solid waste (MSW) requires in most cases a different gasification system than other biomass feedstock, since it differs in chemical composition. In this research, due to the limitations it poses on the type of gasification system, waste biomass is not taken into consideration as potential feedstock.

The suitability of the feedstock was tested to the following three parameters:

Availability: The availability of the feedstock was researched using literature, such as the *Biomass Futures* final report, and, more specifically, the *Biomass availability & supply analysis* study performed by *Böttcher et al. (2012)*.

Logistical chain: The logistical chain was also taken into account for the different feedstock possibilities. The main focus here is on the existing infrastructure and geographical location of the feedstock. Local cost-supply curves, like used by *de Jong et al. (2015)* are used to investigate the feedstock locations and possible logistical chain. Note that not only local feedstock is taken into account, but also the availability and possibility of importing feedstock from overseas, such as pelletized wood, is investigated.

Price: The different feedstock have different cost structures, varying from low costs for black liquor or demolition wood to high costs for annual crops and pelletized wood (*Fritsche, 2013*). This can highly influence the viability of the business case, since in some cases feedstock can comprise 50% of the total production costs (*Wu, 2014*).

3.1.2. Gasification systems

Roughly 4 different types of gasification reactors can be identified as proven technology for biomass feedstock, i.e. Fixed Bed, Fluidized Bed, Entrained Flow and Plasma Arc gasifiers (*Wu, 2014 ; E4Tech, 2009*). *Güell et al. (2012)* select the Fluidized Bed reactor and the Entrained Flow reactor as the most promising gasification systems for biomass to liquid processes, due to, amongst others, their large capacity ranges.

The possible types of gasification systems are tested for different parameters, such as the maximum capacity, feedstock flexibility, techno-economic performance and technology status in order to make a selection of the most promising technologies. The performance of each gasification system on these indicators is adapted from general research on gasification systems, such as the research from *E4Tech (2009)*, *Pytlar (2010)* and *Wu (2014)*. In addition, *Hu et al. (2012)*, *Güell et al. (2012)* and *Swanson et al. (2010)* have done specific research to the suitability of different types of gasification systems for synthetic liquid fuel production.

In addition to these indicators, the quality of the syngas output of the gasification systems is also important. As discussed in the theoretical background, the output syngas can have different qualities, depending on multiple factors (see 2.2. Gasification systems for these factors). This is taken into account while selecting suitable supply chain configurations.

Another important parameter that is used to scope the list of gasification systems is the size of the co-firing unit. For an economically viable production process of renewable jet fuel via an FT process, a minimum size of the gasification system is required. This is taken into account in the selection process for a co-firing production unit. Research of *E4Tech (2009*) showed that systems below 100 kt/yr biomass to liquid fuel output (i.e. around 1,500 odt/day biomass input, depending on the type of biomass) can be neglected, since these will not be cost-effective for a Fischer-Tropsch processing plant.

3.1.3. Coal-fired power plants

The selection of suitable coal-fired power plants was done through searching available open-source coal-fired power plant databases like 'Enipedia'[2] and through direct connections at different utilities in Europe.

The suitability of different coal-power plants to be selected as an archetypical case study depended on their score and fulfillment of the following three parameters:

[2] Available at: http://enipedia.tudelft.nl/wiki/Main_Page

Location: The existence of an infrastructure system to supply biomass depends on the location of the coal-fired power plant. Firstly, since lignite power plants are often located closely to the source of lignite, they will most likely lack an extensive infrastructure system and are therefore not of interest for a case study. Secondly, the location of the plant also influences the cooling process of the plant (i.e. an air-cooled system far away from rivers or a water-cooled system near rivers). Thirdly, there must be enough space available for the installation of the additional units. Next to this, since the two case studies should be archetypes for multiple other power plants, the location selection was adapted to this. Therefore, it is suggested that one plant should have great infrastructure possibilities (e.g. in the harbour of Rotterdam) and one plant should have great local feedstock possibilities (e.g. in the Nordic countries, where lots of woody biomass feedstock is available).

Size of the plant: As mentioned before, the gasification system should have a minimum size in order to have an economically viable production process of FT fuels (*E4Tech, 2009*). The co-firing unit which will be placed next to (or in) the coal-power plant should have a minimum capacity of 1,520 odt/day biomass input (*E4Tech, 2009*), which corresponds with ~ 340 MW thermal input, dependent on the type of biomass. This prerequisite also had implications on the suitability of coal-fired power plants, since it meant that only coal-fired power plants that can handle this amount of syngas in the coal boiler were suitable for this research. This is taken into account when selecting the case studies.

Age of the plant: The age of the coal-fired power plant is also taken into consideration. Since the expectation is that the coal boiler will be replaced around 2025 on average for an FT add-on, the plant should at least be operational until then. But, on the other hand, the plant should already be at least 15 years old, since the amortization on the assets and infrastructure should have already taken place. Only plants that are within these limiting constraints are taken into account.

Moreover, the willingness of utility companies to cooperate on case studies is also an important factor in establishing the supply chain configurations and the two case studies.

3.2. Case studies

At the end of the scoping of the supply chain phase, all the important components for the transition from a coal-fired power plant to a renewable jet fuel production facility were identified and tested for their suitability. Using the aforementioned parameters, a merit order for all the components is drafted. This resulted in a shortlist of four potentially promising supply chain configurations. These are identified as the most promising supply chain configurations for different feedstock, gasification system technology and geographic region setups. The total shortlist is given in Appendix B. From this shortlist, a selection for two case studies is made, which mutually clearly differed in structure. In other words, these two case studies represent two completely different possible routes for producing RJF through transforming coal-fired power plants, each tailored to the combination of feedstock, gasification system and geographical region. In order to setup these case studies at existing coal-power plants, the coal-fired power plant database and analyzed data from, amongst others, *Hansson et al. (2009)* is used. The final selection in the combination of a coal-power plant and supply chain configuration to form the case studies is mainly driven by the choice for the most promising supply chain configurations, the willingness of utility companies to cooperate and the availability of data. The two selected case studies are explained separately in more detail below.

The two specific case studies are configured in a model to test the hypothesis for its economic feasibility with real data and simultaneously benchmark two different supply chain configurations and setups. The two case studies are selected on their suitability for this project and can be considered as archetypes for other similar plants. It regards the 23 year-old 625 MW installed capacity Amer 9 plant, operated by RWE and its Dutch subsidiary Essent NL near Geertruidenberg (The Netherlands), and the, currently mothballed, almost 35 year-old 640 MW installed capacity Asnæs 5 plant, operated by DONG Energy near Kalundborg (Denmark). Both case studies were based on actual input data given by RWE and DONG Energy respectively.

3.2.1. Case 1: RWE Amer 9 coal-power plant

The RWE Amer 9 coal-power plant is one of two units at the Amer power station site. Until recently the site consisted of two active units, which together could deliver 1245 MW of electricity and up to 600 MW heat. However, at the end of December 2015, one of the two units (Amer 8) closed down due to a combination of its aging capacity and governmental environmental regulations based on the Energy Agreement (*RWE, 2015*). This Energy Agreement stated that from January 2016 onwards no coal could be added any more to the Amer 8 boiler, making a co-firing an impossible option for this plant. The Amer 9 plant will be 30 years old in 2023, and is therefore also almost at its end of life. So, regarding timing, this is a very suitable plant for a case study. Instead of new investments to extend the lifetime of this plant, the boiler can be switched to a FT synthesis add-on from that moment on.

At Amer 9, already two of the six coal boilers are redesigned to accept wood feedstock. These boilers are making use of pelletized wood. The investment that is already done to optimize the logistics to transport this pelletized wood to the Amer plant and into the boiler accounts for around 35 Million euros (*Bouwmeester, 2015*). This can be seen as an economic benefit (i.e. expenses saved) for the case study. Additionally, Amer 9 has an indirect co-firing unit in place which gasifies waste wood (e.g. demolition wood) at relatively low temperatures, in order to form the so-called wood gas. This gasification unit is an atmospheric CFB gasifier, which means it is not suitable to use for producing FT liquids (*E4Tech, 2009*). However, it should be taken into account that the technology is already available at the plant, and that there are general learnings regarding the technology.

In this case, the decision is made for an Entrained Flow (EF) gasification system with torrefied wood chips as feedstock. Torrefied wood is often used as biomass feedstock for gasification. Due to its ease of transportation and therefore scalability it forms an important option for large-scale plants (*Van Vliet et al., 2009*). The Amer 9 power plant is located next to a waterway that connects it directly to open sea, which indicates perfect logistical conditions to have access to pelletized wood and torrefied wood chips from e.g. overseas. The choice for torrefied wood chips over pelletized wood is based on economic assumptions regarding these two woody biomass feedstocks. Compared to pelletized wood, torrefied wood has the potential of achieving higher co-firing ratios that will result in reducing the CO_2 emissions further, which in turn will benefit the economical value (*Koppejan et al., 2012*). Additionally, when outdoor storage becomes feasible, the logistical cost for torrefied wood will decline, giving it a lower break-even delivered fuel price at the gate of a power plant compared to wood pellets (*Koppejan et al., 2012*).

A typical suitable gasification system for torrefied and densified biomass is an Entrained Flow (EF) gasifier (*Koppejan et al., 2012*). An Entrained Flow system produces a clean syngas from these torrefied wood chips without much pre-treatment necessary. EF gasification is marked as one of the most promising gasification technologies for FT fuels due to the high temperatures and therefore clean syngas it produces (*Boerrigter et al., 2006 ; E4Tech, 2009*). Additionally, the short residence time of the feedstock in the boiler implies that EF is an excellent choice for large projects / scalable projects (*E4Tech, 2009*). This combination makes this setup a suitable one for the Amer 9 power plant. The size of the biomass gasification unit is chosen to a minimal cost-effectiveness level of ~ 400 MW_{th} installed capacity, which corresponds with an input flow of 70 ton torrefied wood chips per hour (*E4Tech, 2009*). The exact thermal capacity in the model is 389 MW_{th} based on a Lower Heating Value (LHV).

At the Amer 9 site a heating district is present. The residual heat that is delivered by the current configuration needs extra energy before it can be delivered to the heating district (*Bouwmeester, 2015*). Therefore, the total amount of heat that is delivered to the heating district is actually derived from the electricity it would otherwise produce. This means that there is a certain amount of heat retrieved from burning coal, which is not allocated to the steam turbine to generate electricity, but is allocated to the heating district. The conversion ratio that is used by RWE is 1 MW_e is needed to produce 6 MW_{th} (*Bouwmeester, 2015*). Because the price of heat is also derived from the price of electricity following a similar conversion as to the amount of power that is derived from the heat, the difference between whether heat or power is produced has little influence on the economic benefits. Therefore, in this case, in correspondence with Mark Bouwmeester, the assumption is made that there is no heating district installed and no heat is delivered for the ease of the calculations (*Bouwmeester, 2015*).

With this chosen setup, the plant can function as an archetype coal-power plant for other relatively large plants that are situated directly or near sea.

3.2.2. Case 2: DONG Energy Asnæs 5 coal-power plant

The DONG Energy Asnæs 5 coal-power plant is one of three units at the Asnæs Værket site. The three units have a combined capacity of 1057 MW electricity and 741 MW heat production. Currently, however, only the smallest unit (Asnæs 2, 147 MW) is in production due to an overcapacity and regulations in the Danish power sector (*Gøbel, 2015*). This means the Asnæs 5 coal-power plant is currently mothballed. The plant is built in 1981 but received a lifetime extension upgrade in 2005, which should have extended its lifetime with 25 years. DONG Energy did not make a decision yet what they propose to do surrounding the Asnæs 5 power plant. The most likely scenario is that a new 100% biomass power plant will be built next to the current plant. This new plant will generate electricity from wood chips, and provide heat through a heating district to neighboring companies like Statoil and Novo Nordisk (*Gøbel, 2015*). However, this thesis does not take these plans into consideration regarding the proposed feedstock and infrastructure in the gradual transformation of Asnæs 5 from coal-fired power plant to RJF production facility, since these plans are not yet confirmed. In this case, there is only taken into account what is currently in place and calculated how the Asnæs 5 plant could become operational and profitable again.

The decision is made for a pressurized, oxygen-blown Circulating Fluidized Bed (CFB) gasification system with forestry residues and other raw woody biomass as feedstock, such as primary forestry residues, prunings and demolition wood. Compared to the rest of Europe and in relation to its size, a high amount of wood and primary forestry residues are located in Finland and Sweden (*Elbersen et al., 2012*). Next to this, the 'post-consumer' wood potential is relatively large in Denmark as well (*Elbersen et al., 2012*). The logistics to acquire this feedstock are already partly in place at and around the Asnæs power plant. This is because of the Pyroneer test plant DONG Energy had set up here, and the nearby Inbicon A/S biomass refinery, also commissioned by DONG Energy. Additionally, another co-firing plant is relatively close to the Asnæs power plant, namely the Studstrup power plant. With a combined demand of these three for amongst others woody biomass from Sweden, a combined infrastructure network can be joined. The CFB gasification system is only suitable for producing a minimum FT input quality syngas if it is pressurized and oxygen-blown (*E4Tech, 2009*). But the advantages are that it can handle a large variety of input, both in composition as in moisture content (*E4Tech, 2009*). Furthermore, its high capacity range makes is suitable for large-scale projects (*E4Tech, 2009*). The size of the gasification unit is chosen to be similar to the case study performed at RWE. This means that in this case a wet biomass input flow of 125,6 ton per hour is chosen, which represents 73,8 dry ton per hour. This corresponds with a thermal capacity of 336 MW_{th} (LHV).

Furthermore, also at the Asnæs site a heating district is present. This is used to deliver residual heat from the power plant to the nearby town of Kalundborg. Approximately 4500 households are connected to this heating district and are provided of residual heat (*Gullev, 2005*). In this case, this heating district in implemented in the model and used to deliver residual heat in both phases.

With this chosen setup, the plant can function as an archetype coal-power plant for other large scale Scandinavian power plants with a heating district.

3.3. Two phases of implementation

In both cases the same division in two separate phases is assumed: The first phase is based on a setup where the newly built gasification system is designed as an indirect co-firing unit. In this phase, it is assumed that electricity and heat is produced through coal burning and the gasification of biomass, which syngas is used in the coal boiler. After the coal boiler's end of lifetime is reached, the coal boiler will be decommissioned. This is the start of the second phase, in which the gasification unit is linked to a Fischer-Tropsch system. The existing feedstock infrastructure and equipment that is still suitable, such as the steam turbine, will remain being used in this phase. In both cases, a lifetime extension of the steam turbine and auxiliary equipment is incorporated in the projected costs. Figure 11.a. and 11.b. give a concise overview of the processes in a process diagram for phase 1 and phase 2. A more elaborate flow chart diagram of the new parameters that were taken into account for each phase separately is given in Appendix C.

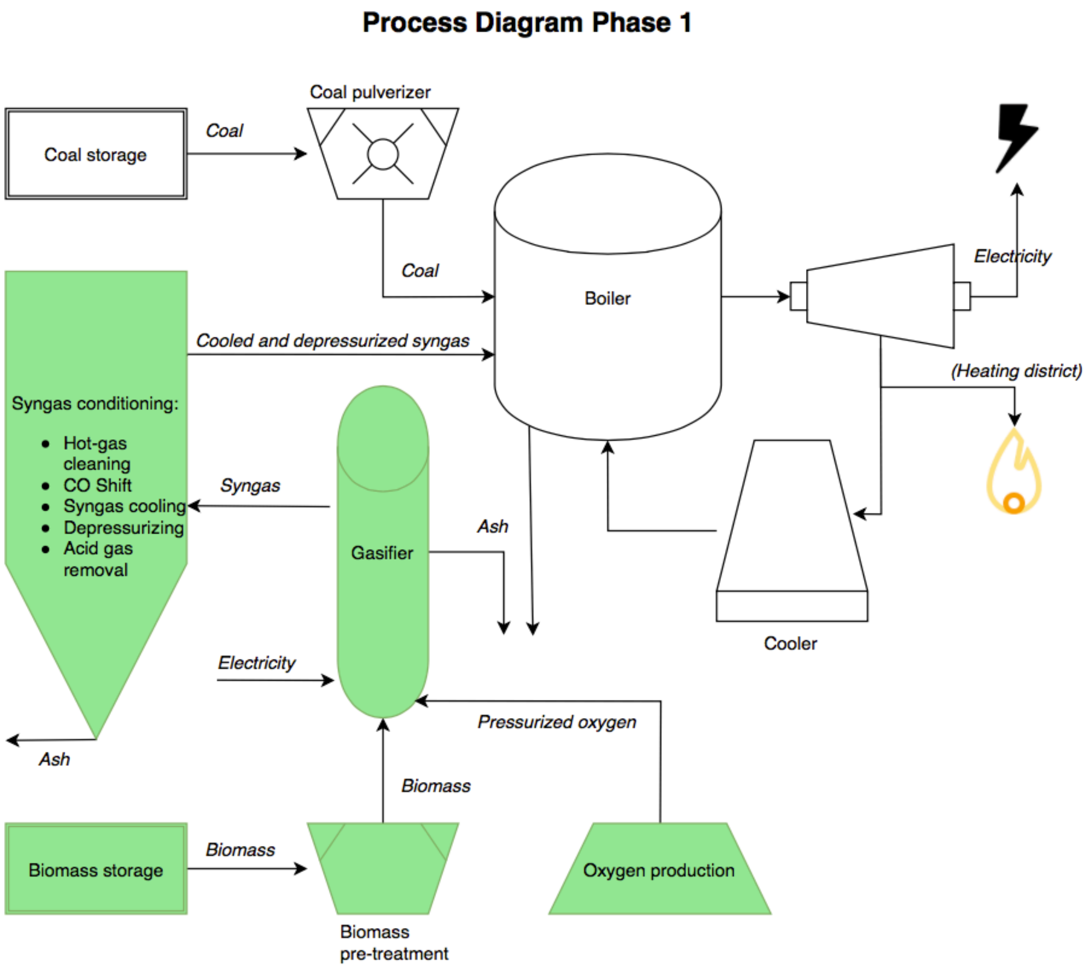

Figure 11.a: Process diagram case study power plant phase 1. Green shaded units are newly installed, the other units are assumed to be present and reused.

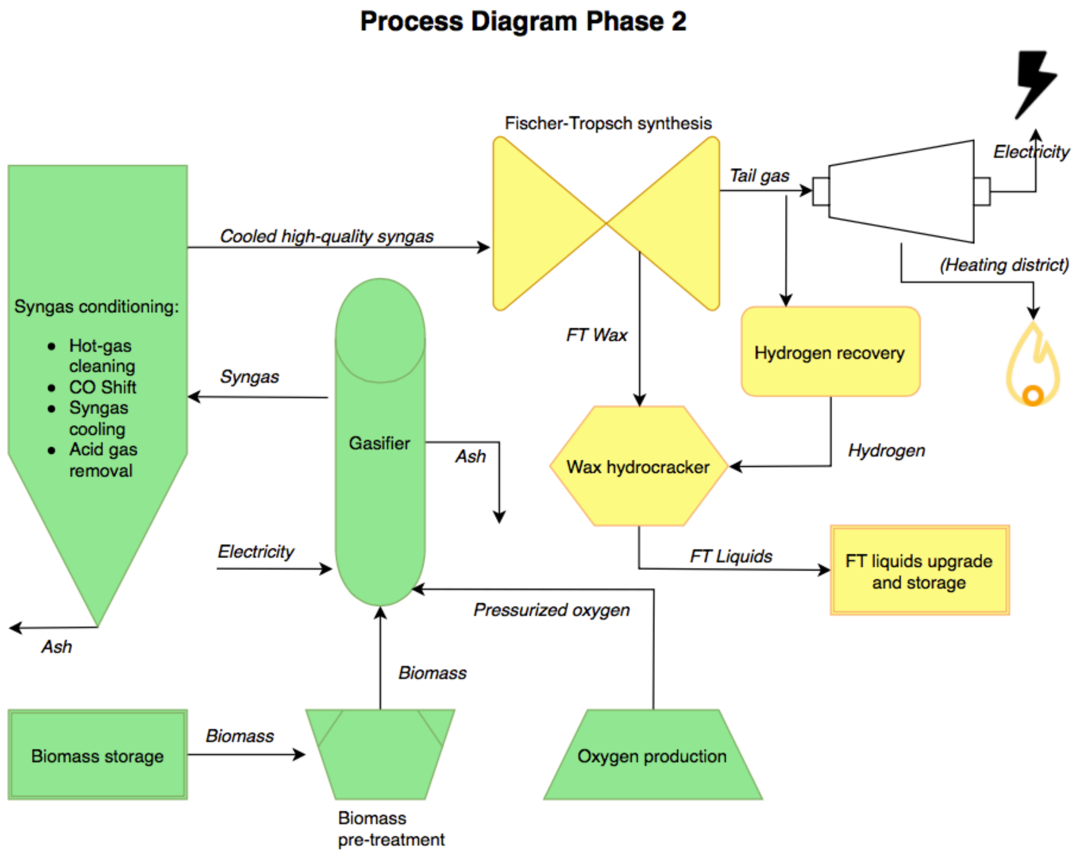

Figure 11.b: Process diagram case study power plant phase 2. Yellow shaded units are newly installed, green shaded units were installed in phase 1, the other units are assumed to be present and reused.

The input data for both the cases is entered in a model developed for this thesis, which uses, amongst others, the mass and energy balance to calculate the output profitability. In order to have a more detailed view on the projects, the timeframe and input for the two phases are modeled for each case specifically. Therefore the different phases are discussed separately, but are clustered per case study in the 'input data' section of this methodology.

3.4. Input data for economic analysis

The techno-economic analysis is performed using Microsoft Excel, which included a technology part (based on mass and energy balances) and an economic part. The performed economic analysis concerns calculations of the complete system of the different case studies, including the capital expenditures (CAPEX) for e.g. adding a gasification unit and FT add-on, as well as the operational expenditures (OPEX) for the processes when in operation. The projects were evaluated on their Internal Rate of Return (IRR) and their Net Present Value (NPV). The IRR was especially chosen as the main result parameter for the project's profitability, since this metric is less sensitive to project size. However, in case studies where the yearly benefits are lower than the yearly OPEX throughout the whole lifetime, no IRR can be calculated, since no revenues are made. This latter was the case for both base line projections in the case studies. But, since the total investment costs for both case studies are quite similar, the NPV can still provide a proper comparative evaluation in these cases.

Although there are similarities in the modeling, the input data for both studies comes from different sources since it regards different technologies and time frames. The case studies are compared with each other per phase, after which a benchmark with two Greenfield projects (which use similar technologies as the case studies) was made.

The input that is kept similar in all the cases is the Weighted Average Cost of Capital (WACC). The WACC is a calculation of the cost of capital in which each category of capital is proportionately weighted. It gives a subdivision between equity value and debt value of the proposed capital needed. This way, the WACC represents the minimum return that a company must earn on an existing asset base to satisfy its creditors, owners, and other providers of capital *(Fernandes, 2014)*. The formula that is used to calculate the WACC is given in equation 2.

$$WACC = \left(\frac{E_{MV}}{E_{MV}+D_{MV}}\right) R_E + \left(\frac{D_{MV}}{E_{MV}+D_{MV}}\right) R_D (1 - T_C) \quad [2.]$$

Here E_{MV} is the total market value of the shareholders equity, D_{MV} is the total market value of the debt, R_E is the cost of equity, R_D is the cost of debt, and T_C is the corporate tax rate. These values are user-adjustable in the model, but on default set to the Western Europe Green & Renewable Energy Industry Standard, as given in table 3 (*Damodaran, 2016*). The Western Europe Coal & Related Energy Industry Standard are currently giving an even slightly lower WACC of 7,14% (*Damodaran, 2016*), but are not chosen as default WACC because of the RJF output calculations in this study. The used value for the WACC is equal to the WACC used in some literature (e.g. *Haarlemmer et al., 2012*), but slightly lower than average WACC's used in most literature. This, however, can be explained by the current historically low interest rates and therefore lower cost of debt than usual.

Weighted Average Cost of Capital	**Constant**	**Part of total market value**
Cost of debt	4,9%	55,4%
Cost of equity	11,2%	44,6%
Tax	12,8%	
WACC	*7,34%*	

Table 3: WACC in the model, following Western Europe Renewable Energy Industry Standard (Damodaran, 2016).

The most important input conditions, like the project timing, used in the model for the case studies and benchmark calculations are given in table 4.

PROJECT TIMING AND INPUT	RWE AMER 9	DONG ASNAES 5	EF + FT[a]	CFB + FT[b]
Gasification module				
Construction Start Date	01/01/17	01/01/17	01/01/17	01/01/17
Construction Length (months)	12	12	12	12
Operation Start Date	01/01/18	01/01/18	01/01/18	01/01/18
Operation Length (years)	25	25	25	25
Operation End Date	01/01/43	01/01/43	01/01/43	01/01/43
Fischer-Tropsch add-on				
Installment of FT after (years)	5	10	0	0
Construction Start Date	01/01/22	01/01/27	01/01/17	01/01/17
Construction Length (months)	12	12	12	12
Operation Start Date	01/01/23	01/01/28	01/01/18	01/01/18
Operation Length (years)	20	15	25	25
Operation End Date	01/01/43	01/01/43	01/01/43	01/01/43
Operational hours				
Phase 1 Operational hours	8000	8000	8000	8000
Phase 1 District heating hours	-	5500	-	5500
Phase 2 Operational hours	8000	8000	8000	8000
Phase 2 District heating hours	-	5500	-	5500

a: EF + FT is an Entrained Flow gasifier + Fischer-Tropsch add-on as given in Haarlemmer et al. (2012).
b: CFB + FT is a pressurized Circulating Fluidized Bed gasifier + Fischer-Tropsch add-on as given in Hannula et al. (2013).

Table 4: Input conditions for the different case studies and benchmark calculations.

Since the end of lifetime of the Amer 9 plant is expected in 2023, the Fischer-Tropsch add-on will be installed five years after the beginning of the project in 2017, so it can be operational at the moment that coal boiler’s end of lifetime is reached.

The Asnæs 5 plant is currently mothballed, but received a lifetime extension in 2005. Therefore the coal boiler and steam turbine are expected to last for the coming years. To differentiate this case from the RWE Amer 9 case, it is assumed that 10 years after the beginning of the project, the FT synthesis add-on is installed. This provides a longer window for electricity generation through coal burning combined with the indirect co-firing gasification unit. Since Denmark’s share of renewable energy was in 2013 already 26,7%, it is well set to accomplish the EU 2020 renewable energy target of 20% of total energy consumption from renewable resources (*Danish Energy Agency, 2015*). Therefore the later switch to FT fuels and longer period of burning coal is not in breach with environmental regulations.

The EF + FT case regards a Greenfield project with an Entrained Flow gasifier and Fischer-Tropsch add-on, based on the same feedstock and technology combination from the same literature as used in the RWE Amer 9 case study. The CFB + FT case regards a Greenfield project with a pressurized Circulating Fluidized Bed gasifier and Fischer-Tropsch add-on, based on the same feedstock and technology combination from the same literature as used in the DONG Energy Asnæs 5 case study. For these benchmark calculation cases the same start date as for the two case studies is given, in order to provide a level playing field. For similar reasons, the lifetime of these cases is set to equal the lifetime of the case study projects.

Table 5 denotes the general input information and mass and energy balances for both case studies and both phases in the phased transition.

INPUT	RWE AMER 9	DONG ASNAES 5
Gasification system		
Gasifier type	Entrained Flow	Pressurized CFB
Biomass type	Torrefied wood chips	Woody biomass
Biomass input dryer (t/h)	-	126
Biomass input gasifier (t/h)	70	74
Biomass input (MWth)	389	336
Efficiency gasifier biomass to electricity[a]	40,0%	40,0%
Coal Boiler		
Installed capacity (MW)	625	640
Coal input boiler (t/h)	94	96
Efficiency coal power plant	40,9%[b]	36,0%[c]
Mass & Energy Balance (PHASE 1)		
Feedstock coal input (kt/yr)	750	768
Feedstock biomass input (kt/yr)	560	590
Power input gasifier + oxygen plant (MW)	44	27
Electricity output coal (MW)	256	227
Electricity output gasifier (MW)	156	127
District heat output coal (MWth)	-	59
District heat output gasifier (MWth)	-	20
Total process energy efficiency phase 1	38,9%	43,1%
Mass & Energy Balance (PHASE 2)		
Feedstock biomass input (kt/yr)[d]	560	590
Power input gasifier + oxygen plant (MW)	44	27
RJF output (kt/yr)	*63*	*58*
Renewable diesel output (kt/yr)	*27*	*25*
Naphtha output (kt/yr)	*22*	*21*
Total FT liquids output (kt/yr)	112	104
Electricity output (MW)	55	29
District heat output (MWth)	-	79
Total process energy efficiency phase 2[e]	52,2%	73,1%

a: Meerman et al. (2012a) show for both types of gasifier similar efficiencies to electricity.
b: Source: Bouwmeester (2015); c: Source: Gøbel (2015).
d: Based on minimum viable input for FT processes (E4Tech).
e: The connection and use of a heating district explains the higher total process energy efficiency in the Asnæs 5 case study, in regard to the Amer 9 case study.

Table 5: General input and mass & energy balances for both case studies.

The EF + FT and CFB + FT cases are not included in table 5 since these could not be split up into two different phases. Therefore, table 6 denotes the relevant input information and mass and energy balances for these two cases.

INPUT	EF + FT[a]	CFB + FT[b]
Gasification system		
Gasifier type	Entrained Flow	Pressurized CFB
Biomass type	Torrefied wood chips	Woody biomass
Biomass input dryer (t/h)	-	126
Biomass input gasifier (t/h)	70	74
Biomass input (MWth)	389	336
Mass & Energy Balance		
Feedstock biomass input (kt/yr)	560	590
Power input gasifier + oxygen plant (MW)	44	27
RJF output (kt/yr)	*63*	*58*
Renewable diesel output (kt/yr)	*27*	*25*
Naphtha output (kt/yr)	*22*	*21*
Total FT liquids output (kt/yr)	112	104
Electricity output (MW)	55	29
District heat output (MWth)	-	79

a: Based on literature of Haarlemmer et al. (2012).
b: Based on literature of Hannula et al. (2013).

Table 6: General input and mass & energy balances for the Greenfield cases.

To construct the RWE Amer 9 case study mass and energy balances, input data from RWE is used, which is mainly derived through interview sessions with Mark Bouwmeester[3]. The input and output data for the second phase of the Amer 9 project, and for the EF + FT Greenfield case is based on the literature review performed by *Haarlemmer et al. (2012)*. This paper is selected to use as input for this case study since it acknowledges the large variation in, amongst others, the yield and production costs reported in literature until that date. Furthermore, it includes a comparison and analysis of other studies performed on this subject (*Haarlemmer et al., 2012*). These insights provide a solid base for the simulations that are performed in the research of *Haarlemmer et al. (2012)* and automatically create a benchmark of this research to other previous studies. Therefore, in the Amer 9 case study it is assumed that the same Entrained Flow gasification unit + FT synthesis add-on will be installed as the types that are used in the article of *Haarlemmer et al. (2012)*.

To construct the mass and energy balances of the Asnæs 5 case study, input data from Benny Gøbel[4] is used. This concerns previous data of the currently mothballed Asnæs 5 power plant and surrounding heating district. The numbers on the gasification unit and Fischer-Tropsch process are extracted from a case study of

[3] Mark Bouwmeester is Developer at RWE Generation – New Energy
[4] Benny Gøbel is Senior Specialist in Proces Chemistry and Thermal Power at DONG Energy

Hannula et al. (2013). In this study, *Hannula et al. (2013)* discuss 20 different configurations and plant designs for producing FT liquids from biomass. One of these case studies regards a Greenfield pressurized CFB plant with a Fischer-Tropsch add-on based on woody biomass feedstock. A similar feedstock - gasifier supply chain configuration was proposed for the Asnæs 5 case study. Furthermore, in the study of *Hannula et al. (2013)* this gasifier + FT system is connected to a heating district, which is of exactly the similar installed capacity that is needed to feed the municipality of Kalundborg (*Gøbel, 2015 ; Gullev, 2005*). Therefore, this literature study forms an exceptional good basis for the Asnæs 5 case study. Also, in this research the same pressurized Circulating Fluidized Bed gasification system + FT synthesis add-on is assumed to be installed as the types that were used in the article of *Hannula et al. (2013)*. Additionally, this case study by *Hannula et al. (2013)* formed also the basis for the CFB + FT Greenfield case.

Furthermore, data on the energy efficiency of both the gasification systems for indirect co-firing is extracted from *Meerman et al. (2012a)*, since they give a broad overview of the energy efficiencies for different types of gasification systems.

For the main calculations in the model for both case studies, the parameters that are given in table 7 are used.

PARAMETERS	RWE AMER 9	DONG ASNAES 5	EF + FT	CFB + FT
LHV Coal (MJ/kg)[a]	24	24	24	24
LHV Torrefied wood chips (MJ/kg)[b]	20	-	20	-
LHV Wet woody biomass (MJ/kg)[c]	-	8,6	-	8,6
LHV Dry woody biomass (MJ/kg)[c]	-	16,4	-	16,4
LHV FT Liquids (MJ/kg)[c]	44	44	44	44
LHV RJF (MJ/kg)[d]	44	44	44	44
LHV Renewable Diesel (MJ/kg)[d]	43,2	43,2	43,2	43,2
LHV Naphtha (MJ/kg)[d]	44,9	44,9	44,9	44,9
FT Liquids split to end products[e]				
Renewable Jet Fuel	56%	56%	56%	56%
Renewable Diesel	24%	24%	24%	24%
Naphtha	20%	20%	20%	20%

a: Source: Bouwmeester (2015).
b: Source: Haarlemmer et al. (2012).
c: Source: Hannula et al. (2013).
d: Source: Argonne National Laboratory (2010).
e: Subdivision in FT liquids based on Ekbom et al. (2009).

Table 7: Parameters for conversion calculations for both case studies.

3.5. Economic analysis

For the economic analysis, the prices of feedstock and prices of the output products are assumed to be fixed at the current rate for the entire lifetime of the plant. This is chosen for the ease of calculation and the inability to accurately predict future prices. The users of the model can adjust these prices to their own preferences. The Fixed Capital Investments (FCI) and some of the Operation & Maintenance (O&M) costs are derived from the initial investment in the equipment, and therefore vary with a change in the equipment costs. The prices and rates differ at some points between the case studies, due to the difference in the supply chain configuration. For both the case studies the prices and rates are given in table 8.

PRICES PER UNIT	RWE AMER 9	DONG ASNAES 5	EF + FT	CFB + FT
Torrefied wood chips feedstock (€/t)[a]	152	-	152	-
Woody biomass feedstock (€/t (dry))[b]	-	95	-	95
Coal feedstock (€/t)[c]	60	60	60	60
Electricity (€/MWh)[c]	35	35	35	35
Green Electricity (€/MWh)	35	35	35	35
District heat (€/MWh-th)[d]	-	25	-	25
Renewable Jet Fuel (€/t)[b]	480	480	480	480
Renewable Diesel (€/t)[b]	446	446	446	446
Naphtha (€/t)[b]	363	363	363	363
FCI and O&M				
O&M Gasifier (as part of gasifier TPC)[e]	5%[c]	4%[f]	N/A	N/A
O&M FT (as part of FT add-on TPC)[e]	5%[c]	4%[f]	N/A	N/A
Installation of equipment[g]	-[h]	30%[f]	-[h]	30%[f]
Engineering & head office[g]	20%[i]	15%[f]	20%[i]	15%[f]
Start-up costs[g]	5%[c]	5%[f]	N/A	5%[f]
Royalties & Fees[g]	2%[c]	2%[f]	N/A	2%[f]
Annual costs[f,j]	-	-	4%	4%

a: Source: Argus Biomass Markets – ARA spot price (January 2015).
b: Source: de Jong et al. (2015), European average 2014.
c: Source: Bouwmeester (2015).
d: Source: Gøbel (2015).
e: Includes personnel costs, maintenance, insurances, (chemicals and catalysts (FT)).
f: Source: Hannula et al. (2013).
g: Percentages as part of the CAPEX on equipment.
h: Included in the Equipment CAPEX.
i: Source: Haarlemmer et al. (2012).
j: Includes O&M, personnel and insurances; given as a percentage as part of depreciable capital cost.

Table 8: The prices per unit and FCI that were used in the case studies.

In the base case, the green electricity price is kept to the same level as the normal electricity price. In the model this division is made to further analyze the potential of the proposed project if a subsidy or other green electricity incentive would be implemented. For the same reason, the renewable jet fuel, renewable diesel and naphtha price is based on similar products derived from the oil price without a renewable premium. The oil price is based on the spot price for Brent crude oil at December 2014 levels, which is $62 per barrel. The rationale to choosing for the December 2014 level is based on the fact that the current low oil price is below most exploration costs and is therefore expected to rise from 2017 onwards to the December 2014 level in 2021 (*World Bank, 2016*). Additionally, in order to keep the calculations accurate, the biomass feedstock price is therefore selected for the same timeframe as the chosen oil price.

For the Amer 9 case study, the Fixed Capital Investments that are given in *Haarlemmer et al. (2012)* are discussed with Mark Bouwmeester, since the Amer 9 plant already has experience with a gasification system. It was advised to be very careful with assumptions regarding a reduction on the start-up costs and on the head office due to the brownfield nature of the project (*Bouwmeester, 2015*). This is because the lower start-up costs and head office spending could be outweighed by the fact that in an existing power plant case the most optimal position for your new installations cannot be chosen. Furthermore, the learnings of the existing gasification system are that the start-up costs were highly underestimated in that case (*Bouwmeester, 2015*).

For the Asnæs 5 case study the FCI and O&M percentages mentioned by *Hannula et al. (2013)* are used as input. As can be seen in the table, these vary slightly with the input in the RWE case, but since these are correlated to the investment costs and operational costs that are given by *Hannula et al. (2013)*, these values are used. An explanation for the lower O&M and lower engineering costs is the lower complexity of a pressurized CFB system versus an Entrained Flow system, and the lower temperatures experienced in a pressurized CFB system in contrast to the high temperatures in an Entrained Flow system (*E4tech, 2009*).

Based on the numbers of *Haarlemmer et al. (2012)* and *Bouwmeester (2015)* for the Amer 9 case study, the numbers of *Hannula et al. (2013)* and *Gøbel (2015)* for the Asnæs 5 case study, and the numbers given in the aforementioned tables, the overall CAPEX, OPEX and benefits for both case studies are calculated. The resulting numbers are given for phase 1 and phase 2 separately in table 9 and table 10 respectively. These estimations are based on an N^{th} plant with the currently available technology.

Since the configuration of the Greenfield benchmark cases is not split up into two different phases, the numbers on these two cases are given in table 11 separately.

ECONOMICS PHASE 1	RWE AMER 9	DONG ASNAES 5
CAPEX Gasifier (Equipment)		
Feedstock pretreatment (M€)	52[a]	31[b]
Oxygen production (M€)	50[a]	47[b]
Buildings (M€)	-	9[b,c]
Acid gas removal (M€)	-	36[b]
Utilities (M€)	13[d]	-
Syngas cooling (M€)	-	10[b]
CO Shift (M€)	-	6[b]
Hot-gas cleaning (M€)	-	39[b]
Compression	-	9[b]
Syngas conditioning (M€)	44[e]	-
Gasifier (M€)	-	51[b]
Total gasification system (M€)	139[a]	-
Power island (M€)[f]	0	0
Total CAPEX (Equipment) (M€)	**298**	**239**
CAPEX (FCI)		
Installation of new equipment (M€)[g]	0[h]	72
Engineering & head office (M€)	60	36
Start-up costs (M€)	15	12
Royalties & Fees (M€)	6	5
Total CAPEX (FCI) (M€)	**81**	**124**
OPEX		
Biomass feedstock (M€/yr)	85	56
Coal feedstock (M€/yr)	45	46
Electricity use gasifier (M€/yr)	12	8
O&M Coal boiler (M€/yr)	21[i]	15[j]
O&M Gasifier (M€/yr)	9	10
Total OPEX (M€/yr)	**173**	**134**
Benefits		
Electricity from coal (M€/yr)	72	64
Green electricity from biomass (M€/yr)	44	35
District Heating from coal (M€/yr)	-	8
District Heating from biomass (M€/yr)	-	3
Total Benefits (M€/yr)	**115**	**110**

a: Source: Haarlemmer et al. (2012); b: Source: Hannula et al. (2013).

c: A 50% reduction factor is implemented on the given costs in Hannula et al. (2013) due to the brownfield nature of the project, based on de Jong et al. (2015) and Gøbel (2015).

d: Includes buildings and a sulphur plant (necessary to avoid significant air pollution by SO_2 or H_2S).

e: Includes hot gas cleaning, CO shift, syngas cooling, and compression.

f: Already in place in a coal-power plant.

g: Includes amongst others the instrumentation and controls, electrical connections, piping, insulation, and site preparation.

h: The installation costs are already incorporated in the equipment costs.

i: Source: Bouwmeester (2015); includes personnel costs, O&M and insurances.
j: Source: Gøbel (2015); includes personnel costs, O&M and insurances.

Table 9: CAPEX, OPEX and Benefits in phase 1 for both case studies.

ECONOMICS PHASE 2	RWE AMER 9	DONG ASNAES 5
CAPEX (New equipment)		
FT reactor (M€)	-	41[a]
HC recovery plant (M€)	-	8[a]
H2 production (PSA system) (M€)	-	1[a]
Wax hydrocracker (M€)	-	26[a]
FT recycle compressor (M€)	-	1[a]
Total FT synthesis add-on (M€)	115[b]	-
Power Island lifetime extension (M€)	27[c]	0[d]
Total CAPEX (Equipment) (M€)	**142**	**77**
CAPEX (FCI)		
Decommissioning costs (M€)[e]	25	25
Installation of new equipment (M€)[f]	0[g]	23
Engineering (M€)	28	12
Start-up costs (M€)	7	4
Royalties & Fees (M€)	3	2
Total CAPEX (FCI) (M€)	**63**	**65**
OPEX		
Biomass feedstock (M€/yr)	85	56
Electricity use gasifier (M€/yr)	12	8
O&M Gasifier (M€/yr)	9	10
O&M FT add-on (M€/yr)	6	3
Total OPEX (M€/yr)	**112**	**76**
Benefits		
Green Electricity (M€/yr)	15	8
Renewable Jet Fuel (M€/yr)	30	28
Renewable Diesel (M€/yr)	12	11
Naphtha (M€/yr)	8	8
District Heating	-	11
Total Benefits (M€/yr)	**66**	**65**

a: Source: Hannula et al. (2013).
b: Source: Haarlemmer et al. (2012), costs are for the complete unit, including a wax hydrocracker unit and a HC recovery plant.
c: Haarlemmer et al. (2012) incorporates these cost in utilities cost. Subdivision between utilities in phase 1 and phase 2 is made following Hannula et al. (2013).
d: Already received a lifetime extension in 2005 and is currently mothballed (Gøbel, 2015).
e: Source: Gøbel (2015), includes decommissioning of coal boiler, old utilities and old infrastructure.
f: Includes amongst others the instrumentation and controls, electrical connections, piping, insulation, and site preparation.
g: The installation costs are already incorporated in the equipment costs.

Table 10: CAPEX, OPEX and Benefits in phase 2 for both case studies.

ECONOMICS GREENFIELD (BASE)	EF + FT[a]	CFB + FT[b]
CAPEX (Gasifier + FT equipment)		
Feedstock pretreatment (M€)	52	31
Oxygen production (M€)	-	47
Buildings (M€)	-	19
Acid gas removal (M€)	-	36
Utilities in gasification system (M€)[c]	90	-
Syngas cooling (M€)	-	10
CO Shift (M€)	-	6
Hot-gas cleaning (M€)	-	39
Compression	-	9
Syngas conditioning (M€)	44	-
Gasifier (M€)	-	51
Total gasification system (M€)	139	-
Power island (M€)	-	27
FT reactor (M€)	-	41
HC recovery plant (M€)	-	8
H2 production (PSA system) (M€)	-	1
Wax hydrocracker (M€)	-	26
FT recycle compressor (M€)	-	1
Total FT synthesis add-on (M€)	115	-
Total CAPEX (Equipment) (M€)	**440**	**352**
CAPEX (FCI)		
Installation of new equipment (M€)	0[d]	106
Storage Facilities (M€)	110	-
Engineering & head office (M€)	88	53
Buildings and Infrastructure (M€)	66	-
Licenses (M€)	1	-
Start-up costs (M€)	-	18
Royalties & Fees (M€)	-	7
Total CAPEX (FCI) (M€)	**265**	**183**
OPEX		
Biomass feedstock (M€/yr)	85	56
Electricity use (M€/yr)	12	8
Annual costs (O&M) (M€)	18	14
Total OPEX (M€/yr)	**115**	**78**
Benefits		
Green Electricity (M€/yr)	15	8
Renewable Jet Fuel (M€/yr)	30	28
Renewable Diesel (M€/yr)	12	11
Naphtha (M€/yr)	8	8
District Heating	-	11
Total Benefits (M€/yr)	**66**	**65**

a: Based on literature of Haarlemmer et al. (2012).
b: Based on literature of Hannula et al. (2013).
c: Includes steam turbine, oxygen production and sulphur plant.
d: The installation costs are already incorporated in the equipment costs.

Table 11: CAPEX, OPEX and Benefits for the Greenfield cases.

As denoted in the comparison with the Greenfield cases, most of the economic data for the Amer 9 case study is retrieved from *Haarlemmer et al. (2012)* and for the Asnæs 5 case study from *Hannula et al. (2013)*, especially regarding phase 2.

The difference in CAPEX and FCI between the case studies is mainly due to the different gasification system, since an EF gasifier is more expensive than a CFB. Additionally, although *Haarlemmer et al. (2012)* and *Hannula et al. (2013)* treat the differentiation between CAPEX and FCI dissimilar, the total calculations are equal.

The difference in CAPEX and FCI between the Brownfield and Greenfield cases is mainly due to the reuse of existing assets in the Brownfield cases. Because of the use of existing assets the CAPEX and FCI combined are 30 million euro lower in the Asnæs 5 case compared to the CFB Greenfield case, while 121 million euro lower in the Amer 9 case compared to the EF Greenfield case.

3.5.1. RWE Amer 9 case

There is a lot of research available on biomass to liquids processes and the economic performance of different configurations, such as the studies performed by *Larson et al. (2009)*, *Meerman et al. (2012a ; 2012b)*, *Swanson et al. (2010)* and *Tunå et al. (2014)*. A techno-economic analysis on the more specific combination used in the Amer 9 case study of an Entrained Flow gasification system that uses torrefied wood chips to produce FT liquids is, however, mentioned less often in literature. The additional fact that *Haarlemmer et al. (2012)* present simulations based on previously published articles (between the years 2000 to 2011), and offer a comparative study of those articles, proves that it is a well-grounded research.

Since the costs for feedstock and the prices for output are variable over time, but make up a large part of whether or not a gasification + FT project is profitable, only the CAPEX costs are useful to compare with other studies. In this case, it turns out that the CAPEX reported by *Haarlemmer et al. (2012)* are quite high compared to other studies. Figure 12 shows the CAPEX on the x-axis versus the production costs on the y-axis of different studies, including the one of *Haarlemmer et al (2012)* and *Hannula et al. (2013)*.

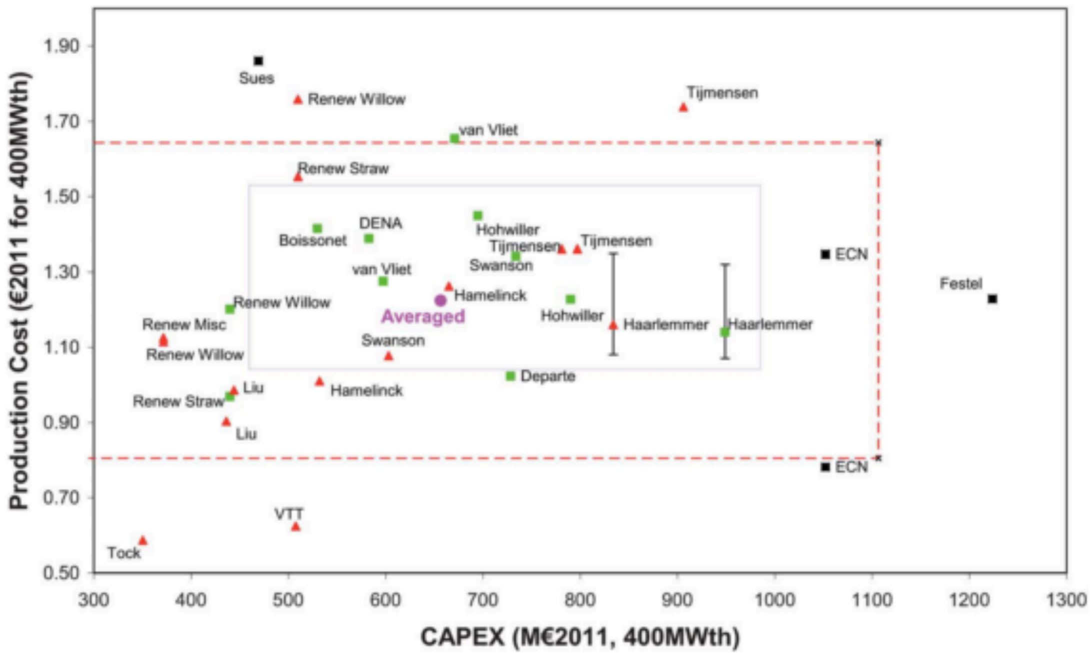

Figure 12: Comparison of literature on CAPEX and Production Cost for different BtL plants (Haarlemmer et al, 2012). A green square represents a pressurized entrained flow reactor, a red triangle represents a pressurized fluidized bed reactor.

When only focusing on CAPEX, it is clear that the study of *Haarlemmer et al. (2012)* is resulting in an approximately 200 to 300 million euro higher investment than the average of other studies performed until 2011, based on a similar installed capacity and an Entrained Flow gasification system. These large variations may be subject to the different interpretation of the authors what to include in CAPEX and what not. For example, *Haarlemmer et al. (2012)* includes the installation costs of the equipment in the equipment price, while others (e.g. *Hannula et al. (2013)*) exclude these from CAPEX and mention them separately.

Choosing, in the RWE Amer 9 case study, for the elaborate research of *Haarlemmer et al. (2012)*, which may yield a higher CAPEX than others show, provides the opportunity to be on the safe side with the calculations. When using the input numbers of the research of *Haarlemmer et al. (2012)* is proving to be an interesting business case, the conclusion can be drawn that the results are actually worth further investigation by RWE. However, this high CAPEX estimation should be taken into account when judging the results, since an underestimation of the potential of this constellation is otherwise lurking.

3.5.2. DONG Energy Asnæs 5 case

Compared to other studies for biomass to liquids based on a pressurized CFB, the results of *Hannula et al. (2013)* seem to be an average estimation, as can be seen in figure 12. The total Greenfield project CAPEX (excluding FCI) of 370 million euro in the study of *Hannula et al. (2013)* are almost similar -but slightly higher- than the results of a Greenfield project CAPEX (excluding FCI) of 361 million dollar from a similar plant in the study of *Swanson et al. (2010)*. Also after including the FCI, these two studies yield similar results. The more recent study of *Tunå et al. (2014)*, who compared a broad range of techniques to produce renewable transportation fuels out of woody biomass, gives a slightly higher total investment. But, taken into consideration that this regards a 400 MW_{th} plant, their estimation is comparable to the numbers in the study of *Hannula et al. (2013)*. Although other studies, such as *Larson et al. (2009)*, consider a different biomass feedstock (in this case switchgrass), or a different nominal capacity, they all provide similar investment cost estimations per MW as the study of *Hannula et al. (2013)*.

Besides this, the case study of *Hannula et al. (2013)* focuses on a Greenfield plant in Finland, which has large similarities to the (economic) climate in Denmark (Hoydal, n.d.). Therefore, this input can be considered as a reasonable representation of the actual costs in the case study for the Asnæs 5 power plant.

In comparison with the RWE Amer 9 case, the total CAPEX for the DONG Energy Asnæs 5 case are considerably lower. This can be appointed to multiple factors, of which the biggest are the difference in type gasification system in phase 1 and the additional power island lifetime extension that is necessary in the 2nd phase of the Amer 9 case.

3.6. Calculations

In order to provide an answer to the research question the data is modeled using Microsoft Excel. This model calculates the Net Present Value (NPV) and Internal Rate of Return (IRR) of as well both the case studies as for other user-entered configurations and projects for repurposing coal-fired power plants to RJF production facilities.

To calculate the profitability of the case study projects, Net Present Value (NPV) and Internal Rate of Return (IRR) calculations are performed. The formulas used for these calculations are given in equation 3 and equation 4 for the NPV and IRR respectively.

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0 \qquad [3.]$$

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+IRR)^t} - C_0 = 0 \qquad [4.]$$

where C_t is the net cash flow for period t, C_0 the initial investment in year 0, and r the discount rate for the project, which is the WACC.

As can be seen, the Internal Rate of Return is the discount rate that makes the NPV of all cash flows equal to 0. Since this cannot be calculated analytically, the IRR function in Microsoft Excel is used to calculate the IRR automatically. The results of the economic analysis are a direct indication of the economic viability of gradually transforming coal-fired power plants to renewable jet fuel production facilities for the two case studies, and for similar coal-fired power plants, for which the case studies formed an archetype.

3.7. Sensitivity analyses

On the results of the economic analyses a sensitivity analysis is performed in order to quantify the sensitivity to uncertainties. Parameters in this sensitivity analysis are the price for RJF, possible subsidies on the renewable electricity generated, the feedstock prices, the variation in the total investments given in different literature studies, and the question what happens if the FT add-on module will not be installed due to e.g. changing market conditions. These analyses are performed to see the impact of the different input parameters on the overall economic viability of the case studies, but also in order to increase the certainty that the archetype case studies can hold up as a model for multiple other coal-fired power plants.

The outcomes of these analyses have both decoupled the costs of gradually transforming coal-fired power plants into RJF production facilities from the specific case studies and put it in a broader perspective, as provided an in-depth analysis on the uncertainties in the case studies. On the basis of these analyses a conclusion is drawn on the viability of using the existing coal-fired power plants for the production of renewable electricity and renewable jet fuel.

Furthermore, the Greenfield benchmark cases are also included in the sensitivity analyses. This is for similar reasons as aforementioned, with the addition of putting the outcomes of the case studies in a broader perspective of producing RJF through biomass gasification + FT in general. This way, a conclusion is drawn on the feasibility of transforming the coal-fired power plants compared to Greenfield projects.

3.8. Strategic analysis for utility companies

Finally, a strategic analysis on the results for utility companies is performed. This includes future recommendations based on the current developments in the sector. The main driver behind this analysis is the anticipation of the proposed phasing out of new coal-power plants. Based on the outcomes of the UNFCCC COP-21 Paris conference environmental regulations are expected to become more stringent and even newly built coal-power plants could be mothballed in the near future. The gradual transformation of these coal-fired power plants to RJF production facilities can become an interesting business case opportunity, as well from a government perspective as from the utility companies perspective. Therefore, a calculation on this gradual transformation for a newly built coal-power plant is performed and compared to a possible claim by the utility company for mothballing the plant.

4. Results

Looking at the input without subsidies and following December 2014 and January 2015 market prices for the input and output, the model shows a negative Net Present Value for both the case studies, as well as for the Greenfield cases. This means the projects are not profitable and therefore do not form an economically viable business case. Since the case studies show yearly losses (i.e. the yearly OPEX is larger than the yearly benefits) no IRR can be calculated, because the initial investment will never be recovered.

4.1. Main results and Net Present Values

A summary of the main results and the NPV for both the projects, based on a discounted cash flow with a discount rate of 7,34%, is given in table 12 for both the case studies as well as the Greenfield base cases.

RESULTS	RWE AMER 9	DONG ASNAES 5
Installation of gasification system (year)	*2017*	*2017*
Total Investments *(phase 1)* (M€)	378,3	362,8
Total yearly OPEX *(phase 1)* (M€)	166,6	134,2
Total yearly Benefits (*phase 1)* (M€)	115,1	109,8
Installation of FT synthesis add-on (year)	*2022*	*2027*
Total Investments *(phase 2)* (M€)	205,5	141,9
Total yearly OPEX *(phase 2)* (M€)	112,3	76,2
Total yearly Benefits (*phase 2)* (M€)	65,6	65,3
Discount Rate	7,34%	7,34%
Net Present Value (M€)	**-1014,2**	**-595,4**
Greenfield base cases	***EF + FT***	***CFB + FT***
Lifetime (years)	25	25
Total Investments (M€)	770,5	535,2
Total yearly OPEX (M€)	115,0	77,7
Total yearly Benefits (M€)	65,6	65,3
Discount Rate	7,34%	7,34%
Net Present Value (M€)	**-1263,1**	**-675,3**

Table 12: Main results and NPV for the case studies and Greenfield cases.

Although both cases have a negative NPV, it can be seen that both Brownfield case studies show more potential than their Greenfield base case counterparts. In the case of the Amer 9 study versus the EF + FT Greenfield case the benefits are 248,9 million euro, or nearly a 20% higher NPV. In the Asnæs 5 case the benefits versus the CFB + FT Greenfield case are 79,9 million euro, or nearly a 12% higher NPV. These reductions can be mainly attributed to the lower CAPEX due to the reuse of assets and the possibility of discounting the future costs of the FT synthesis add-on. These combined benefits account for a reduction of 104 million euro in the Asnæs 5 case and 218 million euro in the Amer 9 case compared to the respective Greenfield cases. In this reduction the additional costs of decommissioning the coal boiler and surrounding utilities are already incorporated.

The woody biomass with pressurized Circulating Fluidized Bed gasifier cases (i.e. the DONG Energy Asnæs 5 case, and the CFB + FT case) show far more potential than the Torrefied Wood with Entrained Flow gasifier cases. This can mainly be explained by the smaller difference between the yearly benefits and the yearly OPEX in these cases. For the DONG Energy Asnæs 5 case, the difference between OPEX and Benefits is in the second phase relatively small (~ 10 million euro), while in the RWE Amer 9 case this difference is more than 50 million euro. This is mainly due to the higher price for the torrefied wood chips feedstock in this latter case.

In order to provide an insight in the subdivision of the costs and benefits in this NPV, an overview of the different costs and benefits over the lifetime of both case studies is generated. In figure 13 and figure 14 this subdivision is graphically shown for the RWE Amer 9 case and the DONG Energy Asnæs 5 case respectively. In both graphs, the mentioned future costs and benefits are discounted with the same discount rate of 7,34%.

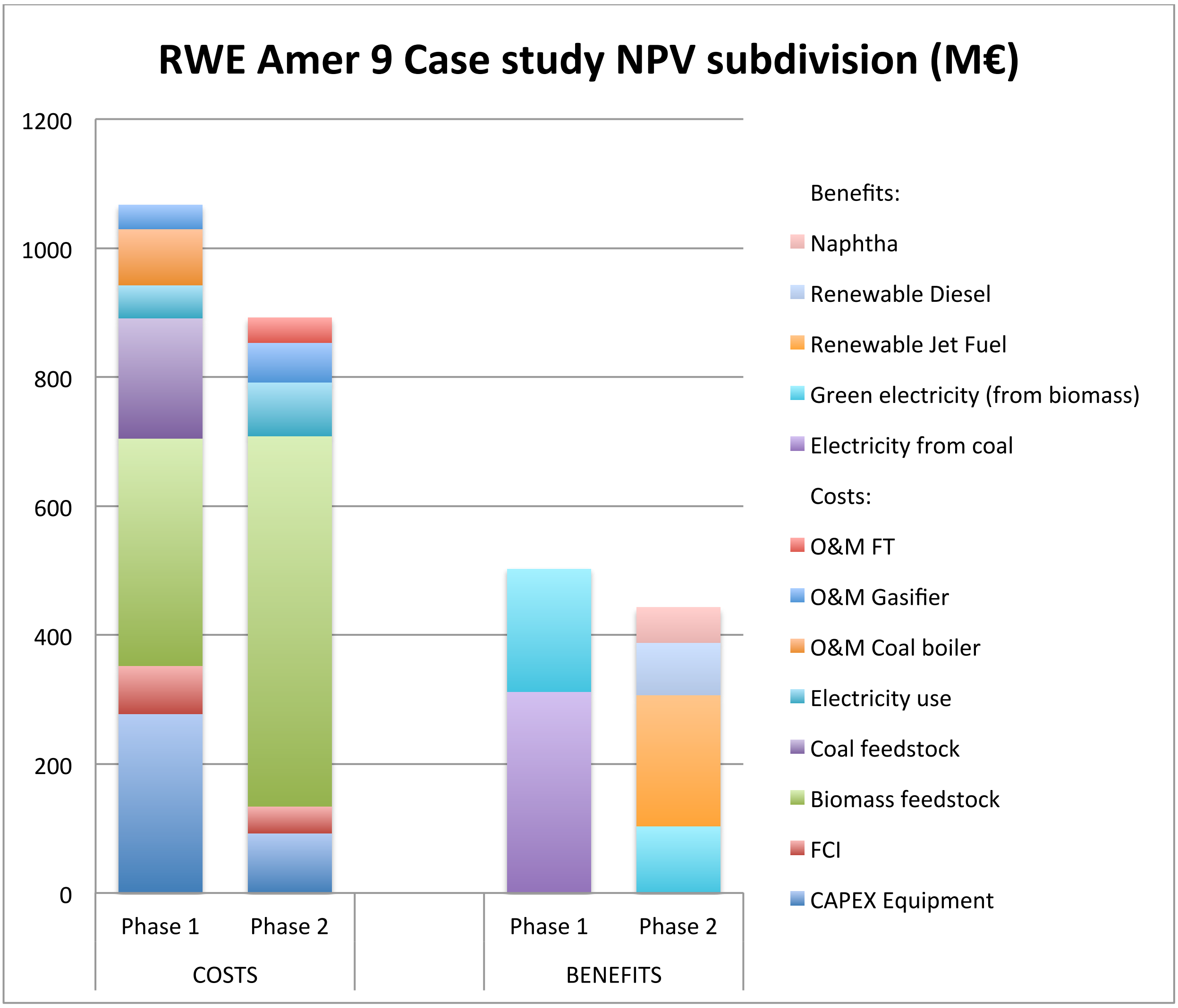

Figure 13: Graphical illustration of the subdivision in the NPV for the Amer 9 case.

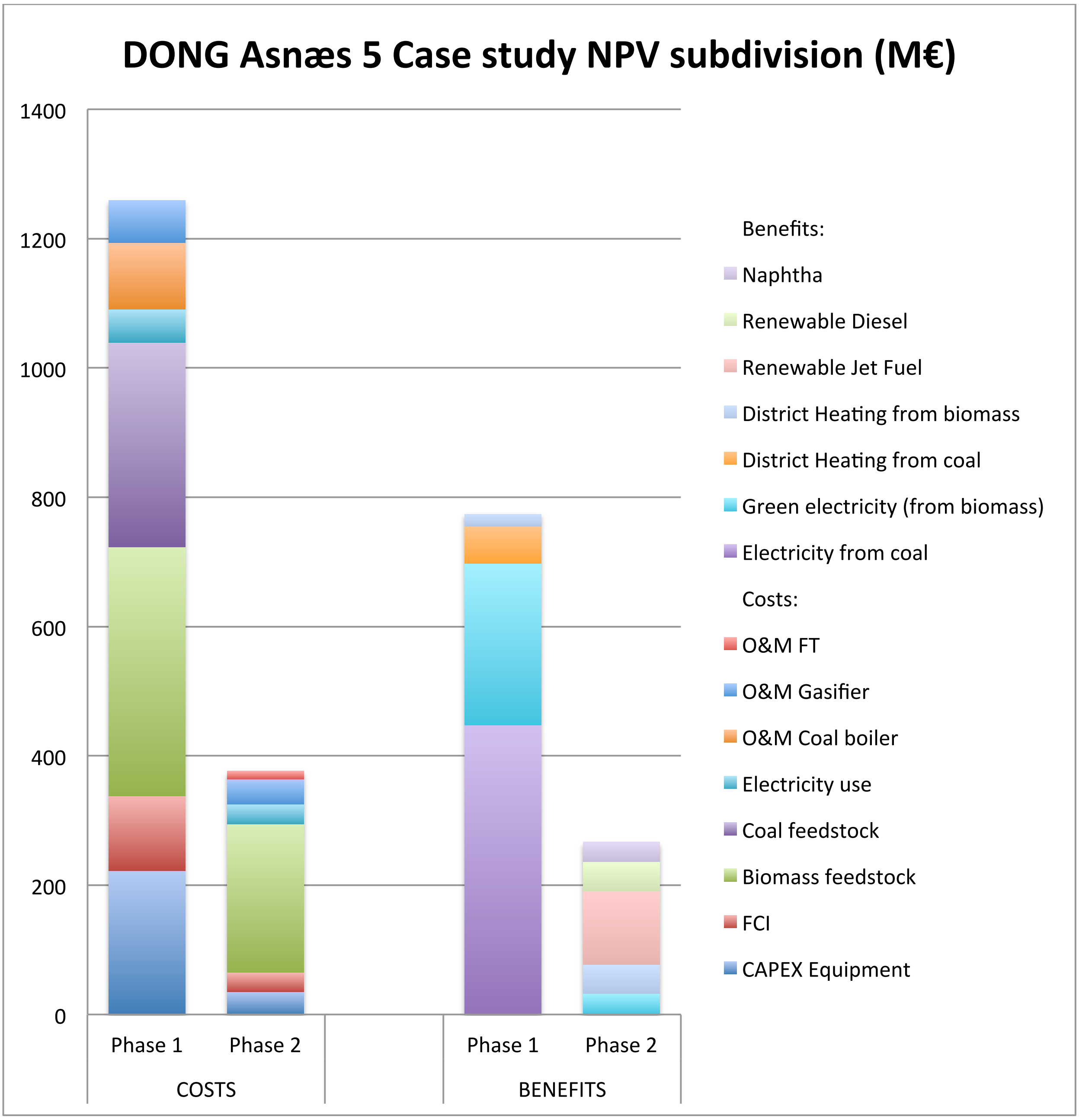

Figure 14: Graphical illustration of the subdivision in the NPV for the Asnæs 5 case.

The major difference between phase 1 and phase 2 in both the costs and the benefits in the Asnæs 5 case can be attributed to the longer period of co-firing. Where in the RWE Amer 9 case after 5 years phase 1 is ended and phase 2 begins is this in the DONG Energy Asnæs 5 case only after 10 years. Obviously, this shifts the costs and benefits more to the first phase.

The benefits of a brownfield project are remarkably visible in figure 13 and figure 14. Not only the reduction in CAPEX through the reuse of the existing infrastructure, but also the benefits in phase 1 of producing electricity through coal-firing are of significant added value for the case studies. This coal-power plant lifetime extension of producing coal-generated electricity covers more than 50% of the benefits in phase 1 for both case studies.

As shown by the above stated figures, the feedstock costs comprise a big part of the total OPEX. Especially in the second phase, ~ 75% of the total operational expenditures can be attributed to the cost of biomass feedstock in both the case studies. Another remarkable outcome is that in both cases ~ 45% of the output benefits in the 2nd phase can be attributed to the revenues of RJF production. Therefore, the impact of the input data which was used for these two parameters was further analyzed in a sensitivity analysis. Additionally, the effect of a higher or lower total investment and the effect of higher earnings on renewable electricity, due to e.g. subsidy schemes, are investigated. These sensitivity analyses are described in more detail below.

4.2. Sensitivity analyses

In order to have an insight in the IRR's of the projects the profitability of the cases needs to be boosted. By simulating the effect of potential subsidies on the projects the feasibility can be improved. To do this, different sensitivity analyses are performed on the results, regarding both the cost structure as on the benefits. As mentioned before, especially the impact of a higher price for renewable jet fuel (due to an increasing oil price or renewable energy subsidies) is interesting to analyze further. Next to this, lower biomass feedstock costs, a renewable premium on the green electricity that is produced, and variations in CAPEX were subject to a sensitivity analysis in order to take their impact in the potential profitability of the case studies into account. Lastly, the effect of a possible later decision that would eliminate the addition of a Fischer-Tropsch module, due to e.g. changing market conditions, is analyzed. All these analyses include both the case studies as well as both the Greenfield cases in order to provide a benchmark.

4.2.1. Renewable Jet Fuel price variations

The price that is used in the model for renewable jet fuel is based on the normal kerosene price without any potential renewable energy subsidies incorporated. In the market, however, a higher price for renewable jet fuel than for normal kerosene is quite common due to corporate green allowances like the KLM Corporate Biofuel Programme (*KLM, 2016*). This is however only to co-fund the small-scale pilot plants and not a guarantee to large-scale premiums. On the other hand, oil prices are expected to rise again after 2020, making even normal kerosene more expensive (*World Bank, 2016*). Therefore a sensitivity analysis on the renewable jet fuel price is given. The relation between the RJF price and the NPV of the case studies and Greenfield cases is given in figure 15, based on ceteris paribus conditions. This means that the price of jet fuel is uncoupled from the price of oil in this analysis, since only the influence of a higher RJF price is investigated and not a corresponding higher price for renewable diesel and naphtha.

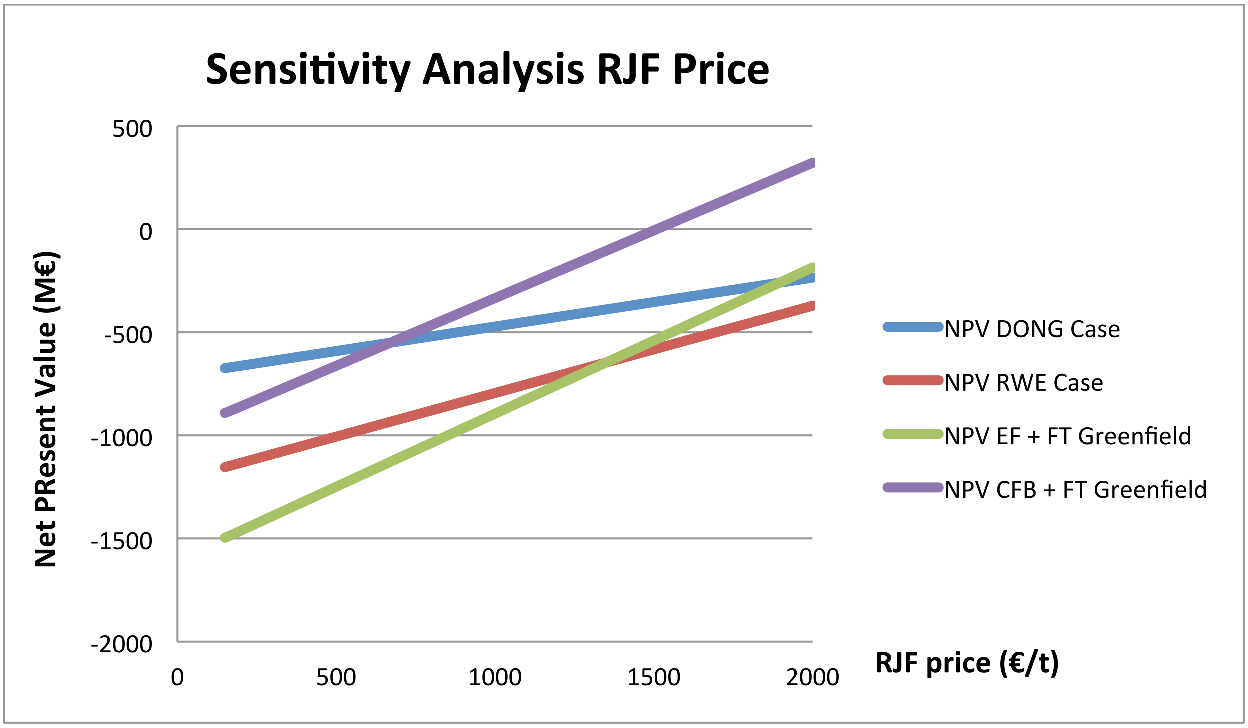

Figure 15: Sensitivity analysis on the RJF price.

As denoted by figure 15, the Greenfield cases show better results when a higher RJF price is calculated than the Brownfield cases. This is because the dependency on RJF revenues is higher in these cases, since from the first operational moment onwards RJF is being produced. This is also reflected in the steepness of the lines for these cases. However, this does not indicate that with higher RJF prices Greenfield cases are better of than Brownfield cases. Brownfield cases could still be economically more feasible than Greenfield cases when the transformation is not gradual but instantly (i.e. from the first operational moment onwards RJF should be produced). The later the FT synthesis add-on is installed, the flatter the curve is (e.g. in the Asnæs 5 case this is in 2027 while in the Amer 9 case in 2022), meaning there is a lower dependency on the RJF revenues.

The results from this sensitivity analysis show that for most of the cases a large subsidy or green allowance on the kerosene price alone will not turn it into profitable projects. Only in the CFB + FT Greenfield case a positive NPV is yielded, at a kerosene price of 1509 €/ton, which is more than 3 times the current kerosene price. In the other cases it turns out to be more unfeasible. Even if the kerosene price would be more than 4 times higher than the current price (i.e. 2000 €/ton), than the Amer 9 case study still yields a negative NPV of -371,1 million euro and an Internal Rate of Return of -6,01%. Note that this latter can be calculated in this scenario, since in phase 2 the benefits of the kerosene will then be larger than the OPEX. The DONG Energy Asnæs 5 case study yields in this 2000 €/ton case a negative NPV of -234,5 million euro with an IRR of -3,84 %, while the EF + FT Greenfield case yields a similar negative NPV of -185,4 million euro.

Focusing on how high the RJF price should be, based on ceteris paribus conditions, for the case studies to be break-even, a further calculation is made using the

Microsoft Excel Solver function. This yielded an RJF price of 2877 €/ton in the Amer 9 case and 2987 €/ton in the Asnæs 5 case. This is approximately 6 times the current kerosene price based on $62 per barrel of Brent oil. In comparison, the Greenfield cases need a kerosene price of 1509 €/ton and 2261 €/ton for the CFB + FT case and EF + FT case respectively. This is approximately 3 to 5 times the current kerosene price based on $62 per barrel of Brent oil. As mentioned before, the impact of a high RJF price is of more influence in these Greenfield cases than in the gradual transformation case studies, but this does not mean the Greenfield cases are economically more feasible.

4.2.1.1. RJF price variation combined with green electricity subsidy

The Dutch government has a subsidy scheme, called SDE+ budget, which provides subsidies to encourage sustainable energy production, such as renewable electricity. Companies and utilities can apply for this subsidy in order to improve their business case in generating renewable electricity. Also for biomass co-firing in coal-power plants an SDE+ budget is available, which was in 2015 fixed to 61 euro per MWh (*RVO, 2015*).

For the RWE Amer 9 case this SDE+ subsidy can form an extra income to improve the business case. Therefore, the same sensitivity analysis as showed above on the price of RJF on the NPV was performed, but this time included with the premium of 61 €/MWh for the produced renewable electricity. The results are given in figure 16. Although it concerns Dutch regulations, which means that only Dutch power plants are eligible for this specific subsidy, other subsidies may be available in the other cases. For the ease of calculation it is assumed in all cases a subsidy of 61 €/MWh for green electricity can be obtained.

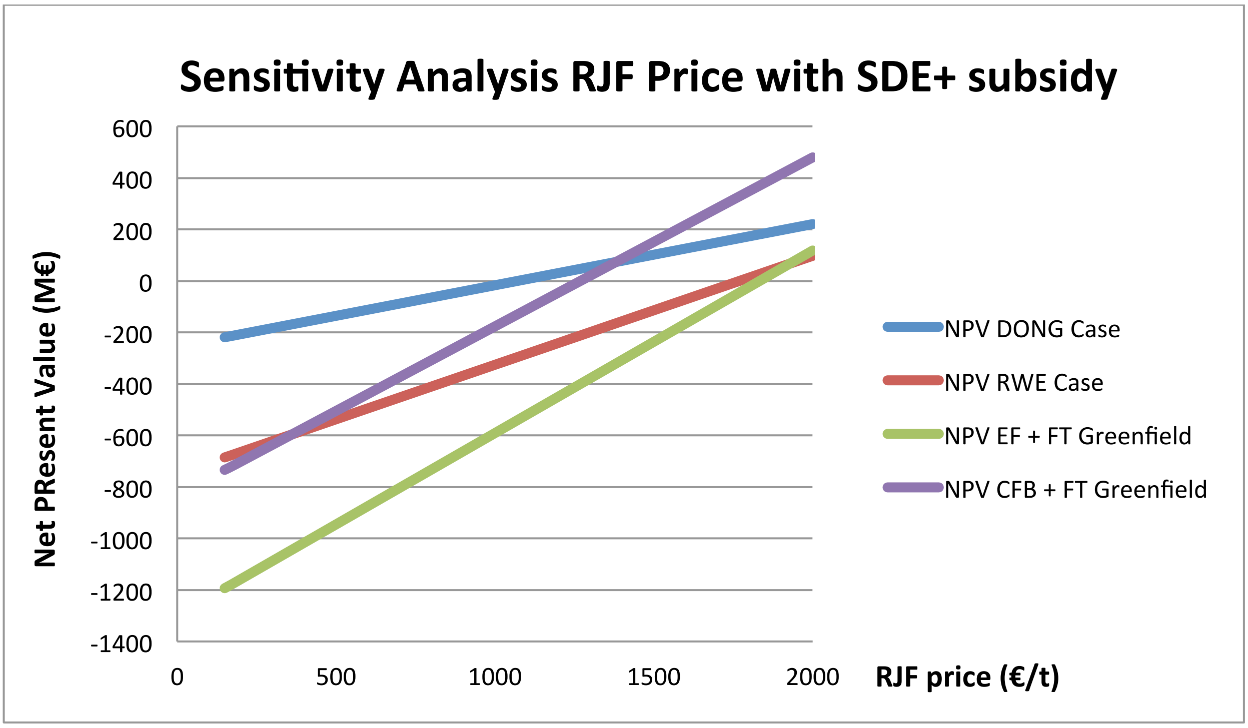

Figure 16: Sensitivity analysis RJF price including SDE+ subsidy of 61 €/MWh green electricity.

As expected, figure 16 denotes that the profitability of the cases improves significantly with the renewable electricity subsidy incorporated in the calculations. Although at the current price of 480 €/ton RJF the cases are all still not profitable, the NPV is significantly higher. The RWE case yields in this case a negative NPV of -545,8 million euro, while the DONG Energy case yields a negative NPV of -140,5 million euro. Since in this latter case, more green electricity is produced during the lifetime of the project, the subsidy has a larger impact on the NPV and therefore this case's break-even point. With the hypothetical SDE+ subsidy on renewable electricity, the break-even point for the DONG Energy case is calculated at 1072 €/ton RJF, which is a little more than only a doubling of the current kerosene price. The RWE Amer 9 has a higher break-even point with the SDE+ subsidy incorporated of 1770 €/ton RJF.

The Greenfield cases yield in this scenario a negative NPV of -518,1 million euro in the CFB + FT case and -959,7 million euro in the EF + FT case. The break-even points are in these cases quite similar to their Brownfield counterparts, namely 1269 €/ton for the CFB + FT Greenfield case and 1834 €/ton for the EF + FT Greenfield case. This is explained by the higher impact of RJF revenues on the business case in these Greenfield projects, but lower impact of a renewable electricity subsidy than in the cases where a Brownfield coal-fired power plant is gradually transformed.

4.2.2. Biomass feedstock price variation

Since the biomass feedstock price is currently quite high, and has proven to be an important factor in the cost structure of the projects, a sensitivity analysis on this input is performed. In figure 17 the influence of the biomass feedstock price on the NPV, under ceteris paribus conditions, is given. The range for this sensitivity analysis is set purposely to incorporate a large variation of the current price of pelletized wood and fresh woody biomass respectively, since it is an important input parameter with little certainty on future price-development. On the one hand, competing biomass projects might cause an increase in price (due to an increase in the demand), but on the other hand new harvesting and production techniques in combination with improved transportation possibilities might lower the price. The prices in the figures are given in euro per dry ton biomass feedstock.

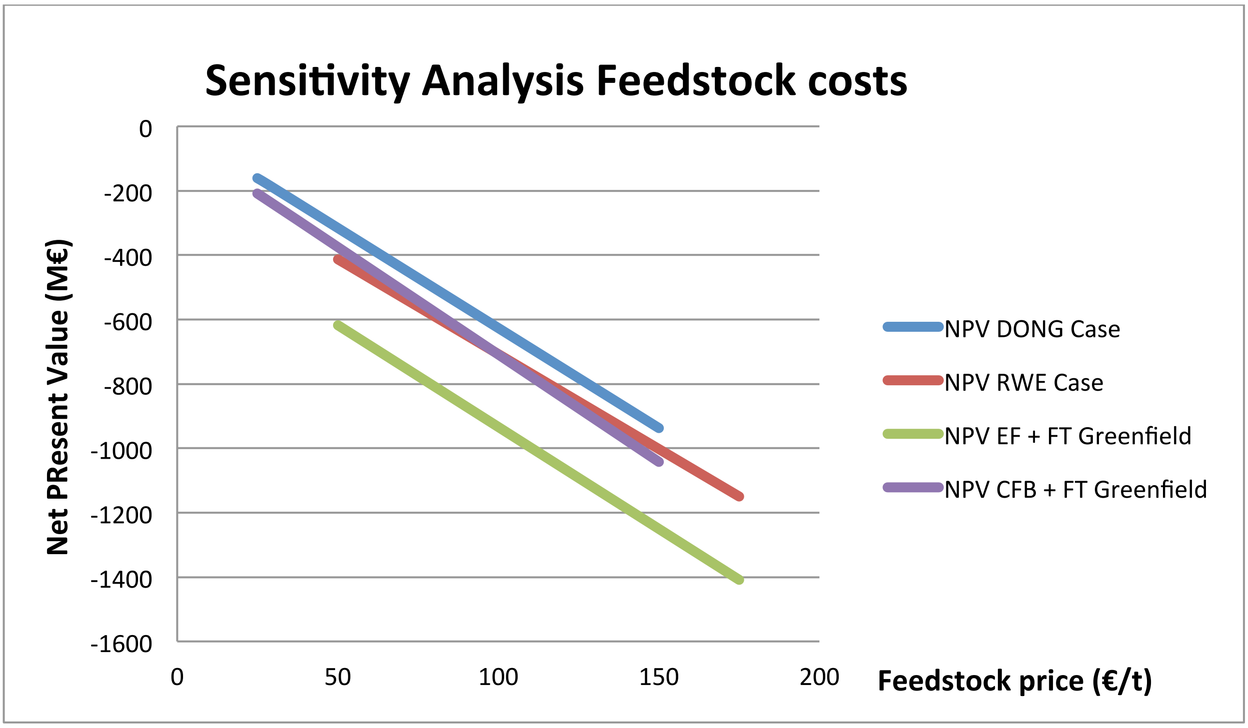

Figure 17: Sensitivity analysis on the cost of biomass feedstock.

As shown in figure 17, in all the cases the sensitivity analysis does not yield a positive NPV in the given ranges. Only a negative feedstock price (e.g. tipping fee) could turn the negative NPV for both case studies as well as the Greenfield cases into a positive one. However, the steep curve that the sensitivity analysis is giving confirms the aforementioned importance of this parameter in the cases.

4.2.3. CAPEX price variation

The total investment in the cases forms a significant part of the total costs, although it is not as dominant in the costs as in the Greenfield cases. Literature reports in some cases even that the CAPEX of a Greenfield project account for nearly half of the total lifetime costs (*Güell et al., 2012*). In the case studies performed in this study, this is not the case. It it could be argued, however, to which extent this can be attributed to the Brownfield nature of the project. Therefore, the sensitivity analysis on the CAPEX includes a range based on literature sources of Greenfield projects. The CAPEX data of different studies with similar gasification systems as used in the case study (i.e. Entrained Flow for the RWE case and pressurized CFB for the DONG Energy case respectively) was extracted from *Haarlemmer et al. (2012)*. These data are non-discounted for future investments, since the article is based on Greenfield projects. Therefore, the data of the sources used in *Haarlemmer et al. (2012)* are first split up in the two main parts (i.e. gasification part and FT synthesis add-on part), and then entered in the model, so the FT add-on investments could be discounted over the period until the module is expected to be installed. The range of the non-discounted CAPEX, retrieved from *Haarlemmer et al. (2012)* for EF gasifiers + FT add-on is between 400 million euro and 950 million euro. For CFB gasifiers + FT add-on this range is between 350 million euro and 900 million euro. As aforementioned in the methodology section this enormous range in CAPEX numbers given in literature are mainly subject to the different interpretation of the authors what to include in CAPEX and what to include in depreciable capital cost. The results of the sensitivity analysis are given in figure 18. Note that the discounted CAPEX is used in these figures. For the EF + FT and CFB + FT Greenfield cases, which are also included in this figure, the non-discounted CAPEX is used, since there are no future investments and therefore discounting the CAPEX would have no effect.

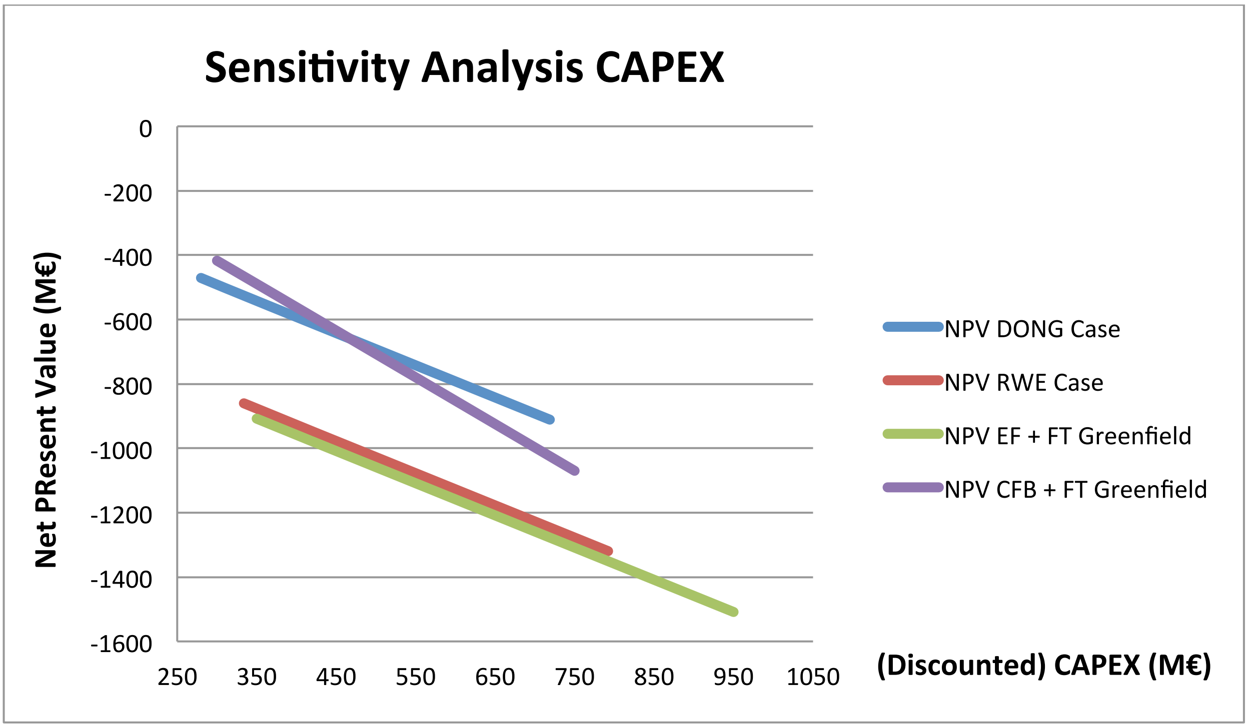

Figure 18: Sensitivity analysis on the (discounted) CAPEX.

The results of this sensitivity analysis show that in both case studies the CAPEX is of importance, but given the range for the costs that is currently available in literature, both projects will not be an economically viable business case if the CAPEX would turn out to be lower than the numbers used in this study. The same applies for the Greenfield cases, of which the CFB + FT case is proven to be the most sensitive for CAPEX fluctuations.

Learning effects on the CAPEX of indirect co-firing units is not taken into account in this thesis, since the proposed start of the building period will be within one year for both the case studies. Learning effects on the FT synthesis add-on module could have been incorporated in the thesis, but are also out of scope. This is because the future investment in the FT synthesis add-on is already discounted in the case studies as if it is a current investment, which is to be spent in the future. This makes the investment in the module already lower, due to the time preference of money. Therefore, implementing learning effects in the future FT add-on investment will have an insignificant effect on the total economic feasibility of the case studies, since the discounted CAPEX for the FT add-on is already quite low compared to other expenditures. However, this exclusion does not indicate that learning-by-doing cannot improve the costs of the module in the future.

4.2.4. No transition to phase 2 calculations

It could be a possible scenario that after the installation of the indirect co-firing unit, the profitability on RJF is still too low to incorporate an FT add-on module in the power plant. In this case, the utilities could consider not implementing the phased transition but extending the lifetime of the power plant and keep using the indirect co-firing unit to generate renewable electricity.

Assuming a lifetime extension of the current coal boiler and steam turbine is necessary, which will cost around 50 million euro, the NPV and IRR for both case studies were calculated (*Gøbel, 2015*). These calculations excluded the phased transition and the second phase of the project, and assumed that the first phase will be extended until the end of lifetime of the gasification system (i.e. after 25 years).

Since the OPEX is in the base case still higher than the benefits for both case studies, no IRR could be calculated. The Net Present Values are also still negative in this scenario, namely -985,1 million euro for the RWE Amer 9 case and -608,5 million euro for the DONG Energy Asnæs 5 case. However, quite remarkably, this forms a slightly better result than the total phased transition for the RWE case (i.e. NPV of -1014,2 million euro), but a slightly worse result than the total phased transition for the DONG Energy case (i.e. -595,4 million euro). This can mainly be attributed to the residual heat of the system that can be used in the Kalundborg heating district in the second phase in the DONG Energy Asnæs 5 case, and the lower cost of feedstock, which means the RJF can be produced at lower costs and is therefore more profitable in this case.

When the earlier mentioned SDE+ subsidy of the Dutch government is introduced in the cases, the results shift. If RWE applies for this subsidy, and the 61 euro per MWh premium for the renewable electricity would be granted, the Net Present Value of the project (without a second phase) will be -185,6 million euro, with an Internal Rate of Return of -6,17%, meaning it will almost reach its break-even point. If the same subsidy is hypothetically applied to the DONG Energy Asnæs 5 case, the project even yields a positive NPV of 42,3 million euro, which means an IRR of 1,33%.

4.3. Strategic analysis on the results for utility companies

The results of this research, including the results of the sensitivity analyses, do not show the most promising results for utility companies with aging coal-power plants on their balances. The upcoming environmental policy changes driven by the COP-21 outcomes will imply more stringent regulations on these plants, and increase the urge to become more sustainable. However, following this research, it is obvious that subsidies and green allowances are necessary in order to form economically viable business cases. Even solely indirect co-firing of biomass to produce renewable electricity (i.e. without producing RJF) in order to increase the sustainability of the plant is proven to be economically not interesting without subsidies of the government on the price of the renewable electricity that is produced. A note that needs to be added here is that the selected gasification system produces a high-quality syngas, which is not per se necessary for indirect co-firing.

However, there are some possible strategies for future plants. When specifically looking at the RWE Amer 9 case in the Netherlands, a strategic cooperation between RWE and the Dutch government can be initiated. As mentioned in the introduction, the House of Representatives recently accepted a resolution to close all the existing coal-fired power plants in the Netherlands at a reasonable term (*Verlaan, 2015)*. This imposes, amongst others, an expected cost on RWE for their Eemshaven coal-power plant (Unit A and Unit B) of around 3 billion euro (*Koot, 2016*). It is expected that RWE will hold the Dutch government liable for these costs, since the Dutch government appointed the location for this plant 10 years ago and invited RWE to build the plant. Looking at the NPV for the Amer 9 case study, a more practical (and possibly sustainable) solution can be found: When a similar gasification + FT installation as proposed in the Amer 9 case study is implemented in the Eemshaven plant, the plant could possibly stay in operation for a longer period. The logistics at the Eemshaven plant are quite similar to the Amer 9 plant, so for a calculation similar conditions can be assumed. When assuming that RWE claims 3 billion euro from the Dutch government for taking the plant out of operation, and taking the reported capital investments of 2,2 billion euro into account[5], a rough calculation to the potential of repurposing this plant can be made.

Assuming that the Eemshaven plant is expected to be amortized following the industry standard of 15 years, the yearly net cash inflow should be 246,7 million euro to redeem the CAPEX investments of 2,2 billion euro, based on a discount rate of 7,34% (as is used in all other calculations in this research). This roughly corresponds with the proposed one-time 3 billion euro redemption fee that is expected to be claimed by RWE from the Dutch government for closing down the plant. But instead of mothballing the plant and spending the 3 billion euro, the proposed transition to a RJF production facility, following the Amer 9 case study in this research, can form an alternative opportunity. Given the resulting Net Present Value of -1014,2 million euro over 25 years of operation for the gradual transformation in the Amer 9 case study, such a transformation will impose additional expenditures to the Eemshaven plant when repurposing it. However, when a 15 year guaranteed yearly subsidy of 246,7 million euro as feed-in tariff for renewable electricity and RJF production is incorporated in these calculations, the NPV for the repurposing and gradual transformation is becoming a positive number of 1034,7 million euro (with an IRR of 37,2%). Note that this yearly 246,7 million euro for 15 years is the same number that would otherwise be spent as a redemption fee for the shutting down of the Eemshaven plant. For a break-even scenario (i.e. NPV = 0) in repurposing the Eemshaven plant, the 15 year guaranteed yearly subsidy can even be lowered to 122,1 million euro. From a government perspective this latter is a far better (and significant lower) spending of the SDE+ budget than just handing over 3 billion euro for closing down the RWE Eemshaven plant. On the other hand, from the RWE perspective it could also form a reasonable compromise, certainly when it assures RWE of future earnings from the Eemshaven power plant as well as

[5] Numbers available at:
http://www.sourcewatch.org/index.php/Eemshaven_Power_Station#cite_note-2

an improved and sustainable image. Furthermore, when the oil price rises in the future, the whole project even could become more profitable for RWE.

This combined investment of the Dutch government with RWE in a phased transition proves in this case to be beneficial to a single governmental reimbursement for closing down the plant. A more in-depth calculation is recommended for future research, since these promising results could not only be applicable for this RWE Eemshaven case, but possibly also for multiple other newly built coal-power plants that are proposed to be phased out.

5. Conclusion

This study was performed in order to answer the main research question, which is: *What is the short- to mid-term technical and economic feasibility of incremental development RJF production using FT synthesis by gradual transformation of existing coal-power plants before 2030?*

Looking at the two case studies, the conclusion can be drawn that in the short- to mid-term the technical feasibility is promising, but the economic feasibility is still very low. There are a lot of constraints and preconditions, as specified in the sensitivity analyses section, which need to be taken into account to make the project economically viable. Although there are quite some differences in the supply chain configuration and the data used for modelling, both the case studies showed large negative Net Present Values for the proposed gradual transition. The main source to this negative NPV is the high price for biomass feedstock and the low price for electricity, RJF and other refined renewable FT liquids. Compared to the Greenfield benchmark cases, the gradual transformation of existing coal-power plants does provide a better overall Net Present Value. The higher NPV of nearly 20% in the Amer 9 case versus a Greenfield EF system and nearly 12% in the Asnæs 5 case versus a Greenfield CFB system can be mainly attributed to the reductions in CAPEX and FCI, plus the possibility to discount the costs of a future investment in the FT synthesis add-on. Furthermore, it can be noted that a CFB gasification system with woody biomass feedstock forms an economically more feasible case than an EF gasification system with torrefied wood chips as feedstock for both Greenfield case studies as for the gradual transformation of coal-power plants. This is mainly due to the high feedstock prices of torrefied wood, and the higher CAPEX on gasifier + pre-treatment for an Entrained Flow system. Additionally, the presence of a heating district next to the plant is of added value for the overall economic feasibility.

When focusing on newly built power plants that are forced to close down due to new regulations, the gradual transformation shows more promising results. In the RWE Eemshaven plant case, a 40% reduction on governmental expenditures can be realized in transforming the plant to RJF production facility compared to a one-time redemption fee for mothballing the plant. This is based on a yearly subsidy of 122,1 million euro for 15 years which is necessary to reach a break-even point, compared to the expected 3 billion euro claim by RWE for mothballing the plant.

5.1. Technical feasibility

The technical feasibility of the proposed case studies consists of a combination of proven and relatively new technologies. Research showed that the combination is looking promising, and the costs are expected to be declining in the future. The main technical drawbacks in the system are related to the required high-quality syngas output, which forms a necessity in the input for the FT synthesis add-on. In order to produce a high-quality syngas an oxygen-blown gasification system is needed. This is associated with high costs of on site pressurizing oxygen. Additionally, the gasification system itself is also pressurized in order to get a high-quality syngas output. However, the syngas that is needed for the indirect co-firing needs to be depressurized to be suitable for the boiler. On top of this, the high-temperature of the output syngas, due to the high temperatures in the gasification system, can form an additional problem for the existing boiler. Therefore, the syngas should be depressurized and cooled down before it can enter an existing coal-fired boiler. This procedure is a difficult process and in terms of energy efficiency not an attractive option, unless this heat can be used in another process or heating district nearby.

5.2. Economical feasibility

The biggest operational losses are made in phase 1 (i.e. the phase before the installation of a FT synthesis add-on), which is not expected beforehand, but is due to the high biomass feedstock prices and the low electricity price. This implicates that a subsidy or green allowance on RJF alone cannot improve the business case as much as a combined subsidy on both the renewable electricity that is generated and the RJF that is produced. This is in contrast with what is seen in the Greenfield cases, where a subsidy or green allowance on RJF has a far higher impact on the feasibility. This means that with a high oil price and / or high RJF price it is economically more feasible to transform the coal-power plants instantly instead of gradually.

Additionally, the DONG Energy Asnæs 5 case proves that the use of residual heat from the process and delivering it to a heating district is increasing the process efficiency significantly and is therefore of added value to make an economically more feasible business case.

De Jong et al. (2015) write in a recent study that without subsidies Greenfield projects for producing RJF are currently proven not to be economically viable. This performed research endorses this fact and adds to this conclusion that, based on the two case studies, producing RJF using gradually transformed coal-fired power plants is also not economically viable without subsidies. However, the use of stranded assets from a coal-power plant does improve the business case for producing RJF through biomass gasification + FT relative to Greenfield production plants.

5.3. Future strategy

The profitability of the BtL technology through gasification + FT is currently still dependent on subsidies. However, it can be expected that due to learning-by-doing this will improve in the future. Therefore it is important to keep investing in these solutions. The government should endorse this by subsidies and environmental regulations on conventional fossil-based energy. A first step is made in the COP-21 agreement, but there still is a long way to go. Instead of seeing renewable energy and fossil energy as two different ballgames, the focus should be on a combined approach. The repurposing of old coal-power plants does show benefits to Greenfield projects and is therefore worth taking into consideration. With a SDE+ subsidy of 61 €/MWh on the renewable electricity produced and a RJF price of 1072 €/ton the repurposing of the DONG Energy Asnæs 5 is economically viable. This is a reasonable future scenario, where government subsidies should be maintained at the current levels and the oil price should approximately double from December

2014 levels. Since this case study forms an archetype for other coal-power plants in Nordic regions, these results could be projected to a total installed capacity of 9,04 GW. This number is based on the 'Global Energy Observatory Database'[6] and includes all the coal-power plants in Finland, Sweden and Denmark that are currently operational.

When looking at newly built coal-power plants, which are proposed to be phased out in the near future, the gradual transformation can form additional benefits. Instead of having governments spend subsidy budget to claims of utility companies for their loss of earnings and redemption fees, it is economically more feasible from a government perspective to transform these coal-power plants to RJF production facilities. This transformation requires lower subsidies than the single redemption fees, and increases the renewable energy production. For the utility companies this transformation can form a compromise in order to extend the operational lifetime of their power plants and assure them of future earnings from their assets. As briefly mentioned in the general conclusion, in a calculation on the newly built RWE Eemshaven plant the yearly subsidy as feed-in tariff for renewable electricity or as a premium on the RJF that is produced should be 122,1 million euro for 15 years in the case of a gradual transformation.

5.3.1. Recommendations from the author

A forced close down of all coal-power plants in Europe is still unthinkable and, if that would happen now, it will result in massive government spending and a poorly reliable electricity grid. Therefore, although the results of this research show an economically unviable business case without subsidies, combining fossil power plant assets for BtL processes and gradually phasing out the fossil fuel can become a promising alternative in the future.

[6] Available at: http://globalenergyobservatory.org/list.php?db=PowerPlants&type=Coal

6. Discussion

In this section, the results and implications of this research are discussed following three categories. First a reflection on the research, methodology and the model is given. This regards mainly the reliability of the results and the possible further extension and improvement of the model. Second, the content of the research and its hypothesis is discussed. Lastly, recommendations for future research are given, which are based on the results of this research.

6.1. Reflection on the research, methodology and the model

As mentioned in the methodology section, the case studies should be considered as archetypes for other similar coal-power plants and therefore the results of the case studies should represent results for similar power plants. However, during the research and modeling some site specific parameters are introduced, making the modeled case studies in some parts very specific for the existing one. Examples of such parameters are the installed capacity, on site available assets and infrastructure (e.g. a new steam turbine or biomass storage facilities), and projected lifetime of these existing assets. Therefore, the results cannot be blindly copied and assumed to represent other power plants with different capacities, different installed assets, or other end of lifetime expectancies. However, all these parameters affect the CAPEX. The installed assets are part of the reduction in the total CAPEX, and with a larger installed capacity, the CAPEX could be easily scaled using scale-factors like the Standardized Cost Estimation for New Technolgies (SCENT) developed by *Ereev & Patel (2012)*. So, the impact is assumed to be relatively small, certainly given the fact that the impact of a higher or lower CAPEX is less significant in the Brownfield case studies compared to the Greenfield cases. Regarding the end of lifetime expectancy and moment of FT add-on introduction, this has a larger impact on the economical feasibility of the case studies and should therefore be taken into account when copying these results to other coal-fired power plants.

The production ramp-up rate that a gasification system normally needs to be fully operational from its construction date onwards is not taken into account in the model. Normally a gasification system only produces 50% of its nominal capacity in year 1 and 80% of its nominal capacity in year 2 after construction (*de Jong et al., 2015*). Due to uncertainties about the future behavior of gasification systems and FT processes, this is not taken into consideration. However, implementing this into the model does form a more realistic scenario at this moment and will further worsen the current business case.

Another addition in the model that would increase the accuracy is the cost allocation of an increasing oil price on the outputs. In this research, a sensitivity analysis is performed on the price of RJF and its impact on the NPV. However, when assuming the price of RJF increases due to an increasing oil price, the price of the other FT liquid outputs (renewable diesel and naphtha) would increase as well. This is not incorporated in the current calculations and is recommended to implement in future continuations of this research.

A final note is that the input data on the gasification system and Fischer-Tropsch synthesis module is retrieved from literature research to the technical and economic behavior of these units. It would, however, give a more accurate picture if actual data from manufacturers of these systems, or operators of these systems, could be used in the model.

6.2. Reflection on the hypothesis

Regarding the benefits of retrofitting power plants, including the benefits of reusing already existing infrastructure and machines, the conclusion can be drawn that this has both advantages as disadvantages over Greenfield projects. There are indeed less CAPEX costs, mainly due to lower Fixed Capital Investments, and furthermore, the existing feedstock infrastructure can be considered as an additional benefit to choose for a Brownfield project over a Greenfield project. However, the lower FCI and costs of infrastructure could be outweighed by the fact that in an existing power plant case one cannot choose the most optimal position for the new installations. This can go on expense of the process efficiency or the installation costs. Another drawback is that new additional infrastructure needs to be implemented in the existing infrastructure, which means that the risk of less efficient routes is significant. In this thesis these drawbacks were taken into account by reducing the advantages on e.g. the head office costs for a brownfield plant. However, further research to the exact advantages and disadvantages needs to be performed.

One of the positive points of transforming an existing coal-power plant is that there is already a permit given for generating electricity and all the other activities, making it easier to set up a new gasification unit. These costs could be implemented as benefits in the model. However, it needs to be further investigated if producing FT-liquids can be done under the same permit, or if there is a chemical processing permit necessary. In the latter case, an existing power plant case could be worse off than Greenfield projects, since the site is not designated for chemical processes. It can be imagined that appeals to a chemical permit at a power plant site from e.g. the neighboring villages and industries will be much higher than at a Greenfield site that is specifically chosen for its suitability to deal with the chemical processes.

An additional remark regarding the site of coal-fired power plants is that it is not set up to deal with a refinery process. This regards both the site's capacity (i.e. it should be large enough) as the absence of a FT liquids distributing network and storage facilities. In both the case studies that are investigated in this research, a chemical industry and open water was nearby. However, this is not the case for all coal-power plants. Therefore, this prerequisite could be incorporated in the choice for the location of suitable coal-fired power plants. For example, in a further study only coal-power plants that are close to refineries or other chemical infrastructure and open water should be taken into account.

6.3. Future research recommendations

One of the main future research recommendations is to do research to other supply chain configurations by selecting other case studies from the shortlist. Especially supply chain configurations with a substantial lower biomass feedstock cost, such as straw feedstock, are highly recommended to further investigate. Also Plasma Arc gasification should be investigated further. In this research the Plasma Arc supply chain configuration is not selected as a case study due to the large uncertainties surrounding the techno-economic performance, because of the novelty of the system. However, since Plasma Arc has significantly lower, and sometimes even zero, feedstock pre-treatment costs, and in combination with municipal solid waste (MSW) a negative feedstock price (i.e. tipping fee), this could form am economic feasible opportunity in the future.

As mentioned before, real input data from manufacturers of gasification systems and FT synthesis add-on modules, or already operating BtL plant data, can form an interesting additive to this research. Because with this input the current theoretical case studies could be transformed to actual business cases, providing RWE and DONG Energy with more specific information on which they can base a their investment decision.

An in-depth analysis on the optimal functioning of the FT synthesis process in the case studies is another recommendation for future research to incorporate in the model. The efficiency of a FT plant can be improved through process integration, gas separation, and FT plant selection (*Güell et al., 2012*). So, for example, the choice for a certain type of catalyst to maximize the carbon efficiency and hydrocarbon yield could be taken into account in order to optimize the process, and therefore increase the feasibility of the case studies. This, however, forms a more general elaboration of the research than a specific recommendation for the transformation of coal-fired power plants into RJF production facilities. Furthermore, the impact of these efficiency improvements on the total feasibility of the projects is expected to be low.

A more specific recommendation is a further investigation in the possibilities with younger coal-fired power plants than the ones used in this research. Regarding the current political change after the COP-21 conference in Paris and the subsequent energy transition away from coal-fired power plants, the risk of stranded assets is getting higher and higher for coal-fired power plant utilities. An example of this can be seen in the Netherlands, where all the coal-power plants are forced to close down in the foreseeable future, including newly built ones. The calculation performed in this research shows an economically feasible case for transforming these plants to RJF production facilities instead of mothballing these. This feasibility is however based on a comparison with redemption fees that are expected to be claimed by the utility companies for the prematurely closing of the plants. A more in-depth research in how these plants can be repurposed, e.g. in a specific case study, and how these costs relate to the actual redemption fees forms an interesting opportunity to further investigate.

A final recommendation for future research is to compare this research with the research performed by CE Delft on the feasibility of transforming the currently mothballed RWE Amer 8 coal-power plant to a 100% biomass power plant (*Warringa et al., 2016*). CE Delft performed this research commissioned by *Eneco* and *Natuur en Milieu* in order to investigate how the Dutch renewable energy targets could be met without biomass co-firing in existing power plants. This is currently a hot-topic in the Netherlands, since the Dutch House of Representatives accepted a resolution to close all the existing coal-fired power plants in the Netherlands at a reasonable term, but at the same time the Minister of Economic Affairs stated that with closing these plants the amount of biomass co-firing that is necessary to achieve the renewable energy targets will not be met (*Van Dijk et al., 2016*). Therefore, other solutions were investigated, of which the recently released CE Delft investigation is one of the most important. The costs that are mentioned in the research for the transformation of the mothballed Amer 8 to a biomass power plant are 900 million euro (*Warringa et al., 2016*), which is quite similar to the results in this research on the transformation of the Amer 9 to a RJF production facility. Further research to the differences and similarities in the CE Delft research and this research is therefore recommended, in order to come to a weighted and comparative conclusion about the feasibility of the proposed gradual transformation in this research in relation to other projects that involve the transformation of old coal-fired power plants.

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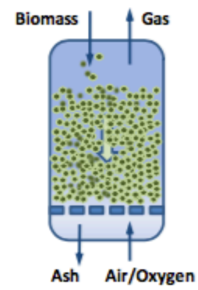
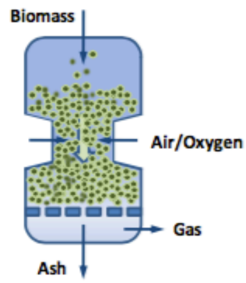
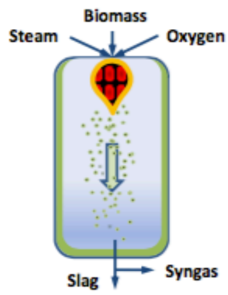
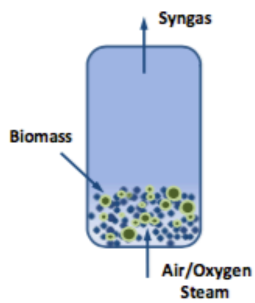
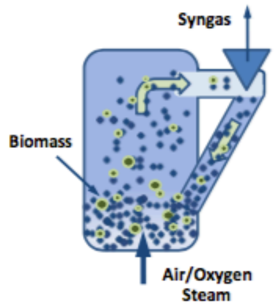
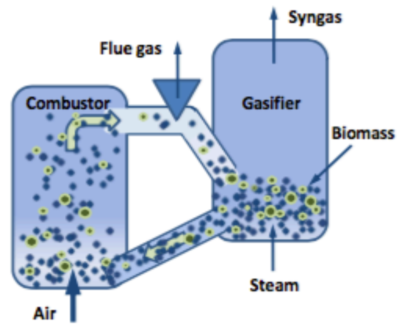
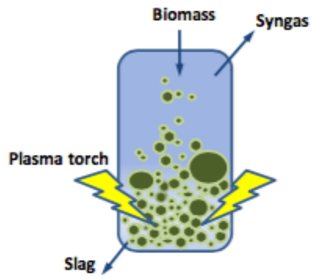
Appendix A. Overview specifications of gasification systems

Copied from the ‘Review of technology for gasification of biomass and wastes’ report drafted by E4Tech, June 2009.

Note that biomass particles are shown in green, and bed material in blue

Updraft fixed bed • The biomass is fed in at the top of the gasifier, and the air, oxygen or steam intake is at the bottom, hence the biomass and gases move in opposite directions • Some of the resulting char falls and burns to provide heat • The methane and tar-rich gas leaves at the top of the gasifier, and the ash falls from the grate for collection at the bottom of the gasifier	
Downdraft fixed bed • The biomass is fed in at the top of the gasifier and the air, and oxygen or steam intake is also at the top or from the sides, hence the biomass and gases move in the same direction • Some of the biomass is burnt, falling through the gasifier throat to form a bed of hot charcoal which the gases have to pass through (a reaction zone) • This ensures a fairly high quality syngas, which leaves at the base of the gasifier, with ash collected under the grate	
Entrained flow (EF) • Powdered biomass is fed into a gasifier with pressurised oxygen and/or steam • A turbulent flame at the top of the gasifier burns some of the biomass, providing large amounts of heat, at high temperature (1200-1500°C), for fast conversion of biomass into very high quality syngas • The ash melts onto the gasifier walls, and is discharged as molten slag	
Bubbling fluidised bed (BFB) • A bed of fine inert material sits at the gasifier bottom, with air, oxygen or steam being blown upwards through the bed just fast enough (1-3m/s) to agitate the material • Biomass is fed in from the side, mixes, and combusts or forms syngas which leaves upwards • Operates at temperatures below 900°C to avoid ash melting and sticking. Can be pressurised	

Circulating fluidised bed (CFB) • A bed of fine inert material has air, oxygen or steam blown upwards through it fast enough (5-10m/s) to suspend material throughout the gasifier • Biomass is fed in from the side, is suspended, and combusts providing heat, or reacts to form syngas • The mixture of syngas and particles are separated using a cyclone, with material returned into the base of the gasifier • Operates at temperatures below 900°C to avoid ash melting and sticking. Can be pressurised	
Dual fluidised bed (Dual FB) • This system has two chambers – a gasifier and a combustor • Biomass is fed into the CFB / BFB gasification chamber, and converted to nitrogen-free syngas and char using steam • The char is burnt in air in the CFB / BFB combustion chamber, heating the accompanying bed particles • This hot bed material is then fed back into the gasification chamber, providing the indirect reaction heat • Cyclones remove any CFB chamber syngas or flue gas • Operates at temperatures below 900°C to avoid ash melting and sticking. Could be pressurised	
Plasma • Untreated biomass is dropped into the gasifier, coming into contact with an electrically generated plasma, usually at atmospheric pressure and temperatures of 1,500-5,000°C • Organic matter is converted into very high quality syngas, and inorganic matter is vitrified into inert slag • Note that plasma gasification uses plasma torches. It is also possible to use plasma arcs in a subsequent process step for syngas clean-up	

Appendix B. Shortlist supply chain configurations

After the broad selection and screening, as explained in the methodology section, four potential supply chain configurations were identified as the most promising supply chain configurations for different feedstock, gasification system technology and geographic region setups. In other words, these four configurations mentioned below are four completely different possible routes for producing RJF through transforming coal-fired power plants, each tailored to the combination of feedstock, gasification system and geographical region.

Configuration 1: 'Proven technology option'
Fresh woody biomass – Fluidized bed gasification – Nordic countries:

- Fresh woody biomass, such as primary forestry residues, prunings and demolition wood;
- A pressurized, oxygen-blown Circulating Fluidized Bed (CFB) gasifier, including pre-treatment, is one of the best technologies available for fresh woody biomass (*E4Tech, 2009*);
- Nordic countries like Finland or Sweden: High amount and density of wood and primary forestry residues compared to the rest of Europe (*Elbersen et al., 2012 ; Mantau et al., 2010*).
- Drawback in this configuration is that the co-firing of fresh woody biomass will probably be cost-ineffective if the feedstock logistics are difficult, e.g. because the coal-fired power plant is not near a forest or near main waterways.

Configuration 2: 'Agricultural potential option'
Agricultural waste/residues – Fluidized bed gasification – Eastern Europe:

- Agricultural residues are the most abundant in the EU and therefore have the largest biomass potential. Scalability is however an issue that needs to be taken into account because of the spread of the feedstock. Next to this, also the high ash component needs to be taken into account, which means that pre-treatment is an important factor. Lastly, agricultural waste/residues consist of multiple different waste streams, which not all are suitable for gasification (e.g. manure) and consist of different cost components. Straw is relatively cheap and therefore preferable (*Monforti et al., 2013*);
- A pressurized, oxygen-blown Bubbling Fluidized Bed (BFB) gasifier, or a pressurized, oxygen-blown Circulating Fluidized Bed (CFB) gasifier;
- Large countries with a large agricultural sector form currently the biggest potential. Examples of these countries are France and Germany. But research shows that Eastern European countries have a very large future potential (Poland especially, but also Romania). For this hypothesis the latter category of countries are of more added value, since these cannot only contribute with a large agricultural sector but also have older coal-fired power plants in use. Additionally, the competition for the agricultural waste/residues is lower in these countries than in for example Germany (*Scarlat et al., 2010*).

Configuration 3: 'Future potential option'

Municipal Solid Waste (MSW) – Plasma Arc gasification – Western Europe:

- MSW forms a huge potential as for feedstock availability, especially regarding the future. Additionally, MSW feedstock is the only feedstock where a tipping fee is included instead of costs. Since biomass feedstock costs can make up a big portion of the total OPEX and even of the total costs of the plant, a configuration with no -or hardly any- feedstock costs is a promising setup (*Valkenburg et al., 2008 ; Wu, 2014*);
- A Plasma Arc gasifier is a logical choice when considering MSW gasification, since no pre-treatment is necessary and it delivers a high-quality syngas. However, this only forms an interesting option with a future decline in equipment costs. In addition, the net efficiency of such a system is low due to its high energy use (electric torch) (*E4Tech, 2009*). A possibility is to use the cheaper coal-fired electricity to power these torches in an indirect co-firing unit setup;
- Western Europe is the most plausible region for such an advanced configuration to work. The United Kingdom is already a front-runner in Europe in MSW gasification projects. This is mainly due to a subsidy system that rewards gross efficiency/electricity consumption, i.e. it ignores the energy needed to power the process. However, since there are learning effects expected in the UK, due to this amount of installed projects, it could well form a promising configuration for this study (*Koppejan, 2015*);
- It is a necessity to find a coal-fired power plant near large amounts of MSW (e.g. a landfill) in order to not waste costs on the feedstock logistics of transporting the MSW (*Hoornweg et al., 2012*).

Configuration 4: 'Large-scale transport option'

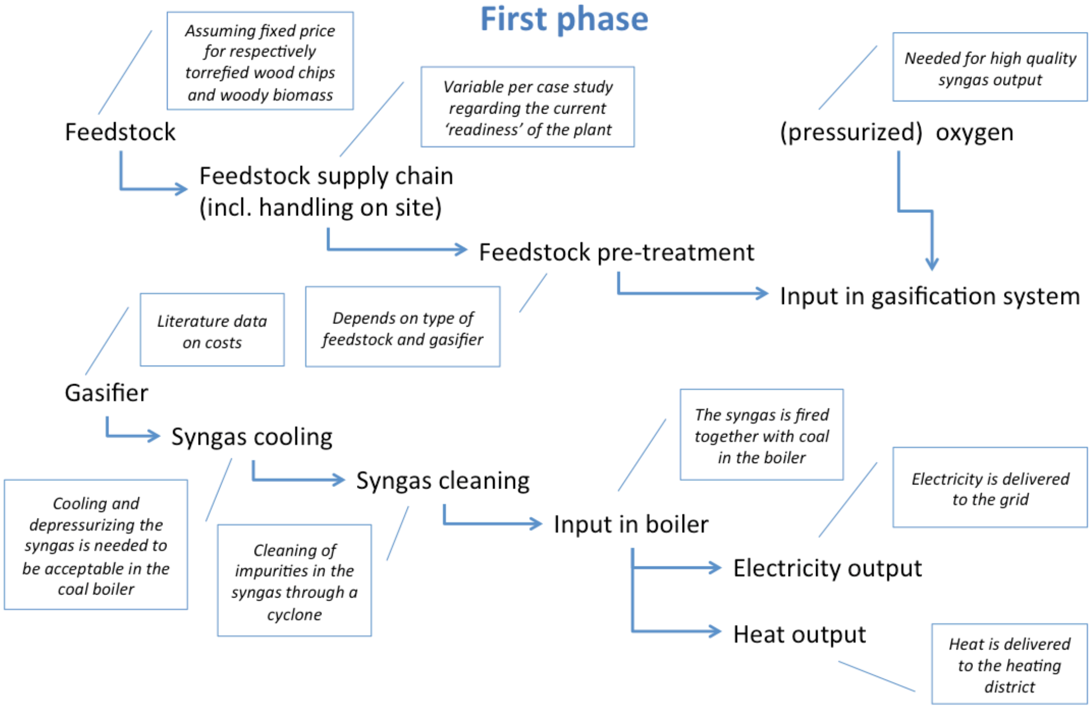
Pelletized wood – Entrained Flow – Western Europe (near main waterways):

- Pelletized wood is often used as biomass feedstock for gasification. Due to its ease of transportation and therefore scalability it forms an important option for large-scale plants (*Güell et al. 2012*);
- Entrained Flow is marked as one of the most promising gasification technologies for FT fuels due to the high temperatures (and therefore clean syngas) and short residence time of the feedstock in the boiler. This latter implies that EF is a logical choice for large projects / scalable projects (*Güell et al. 2012*);
- Western Europe: The location should be near main waterways for the ease of transportation and the availability of biomass infrastructure at the existing coal-power plant is a prerequisite. Possible suitable locations include the Netherlands and the northern part of Germany (near the big ports).

Appendix C. Flow-chart overview of new parameters in plants

Here a more extensive flow-chart overview of the new parameters that were taken into account in phase 1, the transition phase, and phase 2 for the coal-power plant case studies are given.

First phase



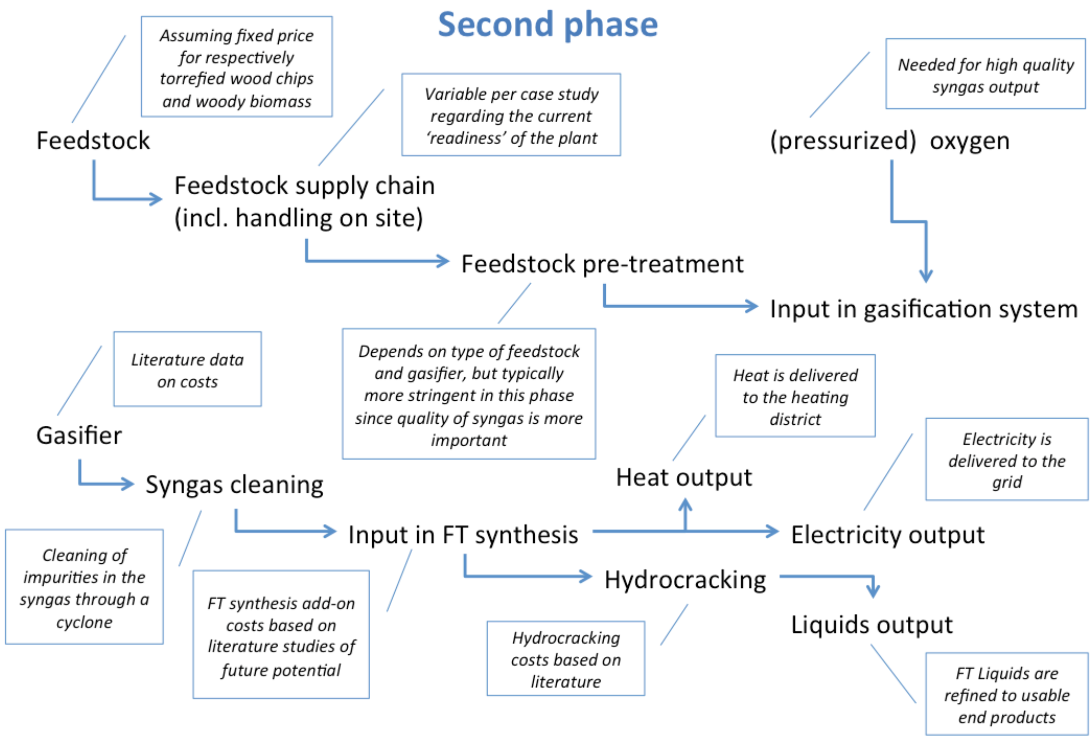
Transition phase

Remove

Old (on-site) infrastructure
→ Coal boiler
→ Syngas cooler (+ depressurizer)

Install

New infrastructure
→ Fischer-Tropsch synthesis
→ Hydrocracker
→ Liquids storage facility


Second phase
Assuming fixed price for respectively torrefied wood chips and woody biomass
Variable per case study regarding the current 'readiness' of the plant
Needed for high quality syngas output
Feedstock
Feedstock supply chain (incl. handling on site)
(pressurized) oxygen
Feedstock pre-treatment
Input in gasification system
Literature data on costs
Depends on type of feedstock and gasifier, but typically more stringent in this phase since quality of syngas is more important
Heat is delivered to the heating district
Gasifier
Electricity is delivered to the grid
Heat output
Syngas cleaning
Input in FT synthesis
Electricity output
Cleaning of impurities in the syngas through a cyclone
Hydrocracking
FT synthesis add-on costs based on literature studies of future potential
Hydrocracking costs based on literature
Liquids output
FT Liquids are refined to usable end products