



**CARBON
NEUTRAL
AVIATION WITH
CURRENT ENGINE
TECHNOLOGY:**

*THE TAKE-OFF OF
SYNTHETIC KEROSENE
PRODUCTION IN THE
NETHERLANDS*

*THE STORY AND
THE REPORT*

CREDITS

COMMISSIONED BY

KLM, Koole Terminals, Oiltanking Amsterdam, Port of Amsterdam, Stichting Sanageest, Shell, Tata Steel, TenneT, and Topconsortium voor Kennis en Innovatie Energie & Industrie

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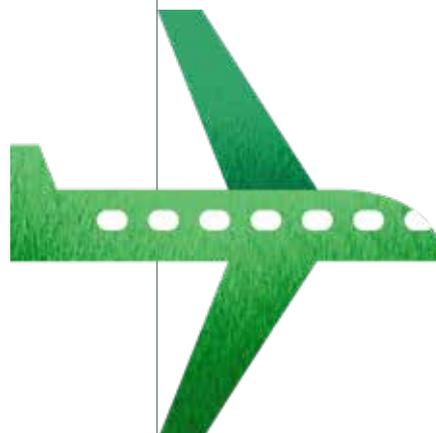
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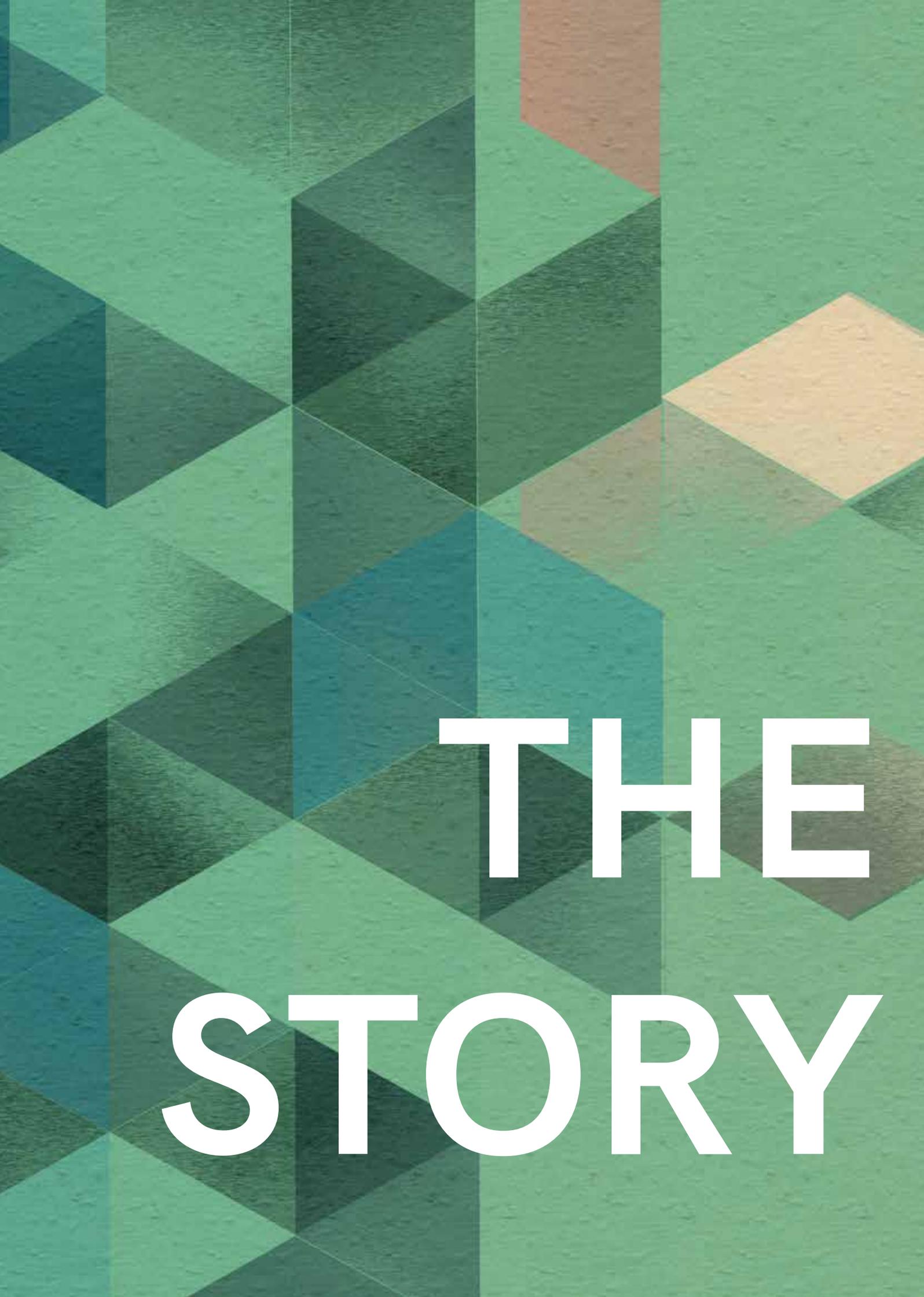


Kalavasta
Climate Neutral Strategies



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THE STORY

AVIATION CAN BECOME CARBON NEUTRAL BY 2050

Quintel and Kalavasta have explored many pathways towards a carbon neutral society. After a long time, we are finally developing a pathway towards carbon neutral aviation.

We did not do it alone. Together with *Shell, Tata Steel, TenneT, KLM, Port of Amsterdam, Oiltanking, Koole Terminals, foundation Sanegeest and the Top Consortium for Knowledge and Innovation Energy and Industry* we developed this research.

On pages 5 - 11 we give you, in simple terms, **THE STORY**. We explain in everyday English how the aviation industry can become carbon neutral and how much this would cost people who want to travel by air.

From page 12 onwards you will find the detailed report, containing the explanations, calculations, business cases and the sources on which **THE STORY** is based. The English in the **DETAILED REPORT** is much more formal and full of scientific and economic language.

We suggest you start with **THE STORY**. It is much easier to read and much shorter. Once you have read the story you can dive into the **DETAILED REPORT** to see how we justify the idea that the aviation sector can become carbon neutral by 2050 for costs that are most probably close to what the sector would have to pay for fossil kerosene!

AMBITION IS TO CUT CO₂ EMISSIONS FROM AIRPLANES, REALITY IS THAT EMISSIONS GROW RAPIDLY

Modern airplanes use kerosene and emit CO₂ as they burn kerosene in their jet engines. Flying is therefore one of the human activities that contributes to global warming. Direct emissions from aviation are more than 2% of worldwide emissions.

Kerosene usage by the aviation industry is set to grow by approximately 2.5 - 3.5% every year for the next 30 years in Europe. For these figures we take into account the growth in passengers and freight and we compensate for efficiency gains. Compared to 2017, kerosene usage would easily double towards 2050 and could even rise to up to 5 times current levels, if efficiency gains would not be realised. Already in 2009 the International Air Transport Association (IATA) set a goal to halve CO₂ emissions by 2050 with respect to 2005. Without additional measures projections are a factor of 6 - 10 times worse than what IATA is aiming for.

Set ambitions in the aviation sector, as of yet, depend on new break-through measures as far as emission reduction is concerned. As a society we do not seem to want to give up our freedom to travel long distances nor our desire to get packages from around the globe on our doorstep quickly. So if we do not want to fly less, we need to find a solution that meets - and ultimately goes beyond - IATA's long-term target.

SOLUTIONS FROM OTHER SECTORS TO BECOME CARBON NEUTRAL DO NOT WORK FOR AVIATION

While in other sectors technologies are available that would allow the sector to become carbon neutral, this is not likely to be the case in the aviation sector anytime soon. For instance, one can switch from a car with an internal combustion engine on petrol to a battery electric vehicle "fuelled" by electricity from a wind- or solar source. As a result, the activity of driving (excluding the manufacturing of the car) does not produce greenhouse gases. There is not such an alternative technology for large airplanes with jet engines on kerosene yet, nor is it likely it will arrive in the coming decades. Current electric

planes can carry up to 10 passengers for up to 1 hour of flight time; in 2035, electric planes are expected to be able to transport 50-100 passengers for 1,000 km - far smaller in both capacity and distance than planes on kerosene.

A second type of solution used in some industries is one in which the main processes are kept intact, but a switch is made to another energy source. The fertiliser industry is a good example. In the Netherlands, they currently use natural gas as feedstock to produce hydrogen. Alternatively, they could use hydrogen produced from renewable electricity as a feedstock, allowing them to produce "green emission-free fertiliser".

The aviation industry has attempted and to a large extent is following this second solution path today. It tries to develop, produce and buy bio-kerosene, which is kerosene produced from plant-based sources. Later in THE STORY we will show that bio-kerosene made from biomass grown in the Netherlands typically requires over 1,000 times more fresh water and arable land than the suggested alternative. More importantly, we think that scaling up bio-kerosene is not the ultimate solution. For example, just supplying Schiphol Airport in 2017 with bio-kerosene would require an amount of farmland 0.5-1.8 times the size of all Dutch farmland (depending on the crop) and an amount of water equal to 22-33 times the current water usage of all Dutch households or multiple amounts of organic waste that is generated by all Dutch households. So far aviation has also used second generation biofuels such as used cooking oil, which does not compete with food production, but cannot scale up as much as the alternatives. Investigation is ongoing for third generation biofuels (algae), but this is currently not yet a viable option from a commercial or environmental perspective.

Hence, we need to look for a third type of solution. A type of solution maybe even unique to this sector. This 'synthetic' solution would be to replace the carbon atoms present in kerosene with reusable or renewable carbon atoms from a non-plant based source.

WE CAN MANUFACTURE (SYNTHETIC) KEROSENE FROM OTHER CARBON SOURCES AND REUSE IT EVERY TIME

Kerosene is a mixture of hydrocarbons, compounds consisting of many carbon (C) and hydrogen (H) atoms. To produce this energy-dense aviation fuel, we thus need at least a source of carbon atoms and a source of hydrogen atoms. It is possible to obtain carbon atoms by capturing carbon dioxide (CO₂) from the air. If we have water (H₂O), we also have a source of hydrogen atoms.

The technology to synthesise carbon and hydrogen atoms into kerosene exists. And so an opportunity opens up to capture carbon and use the hydrogen atoms in water to make kerosene, using solar or wind electricity as energy source. The carbon and hydrogen go back into the atmosphere by burning it: when jet engines burn kerosene, carbon dioxide (CO₂) and water (H₂O) are released. This would be a carbon neutral and circular economy solution.

An intermediate step which would roughly halve emissions would be to take the carbon atoms initially from a concentrated source of CO₂ emissions like an industrial plant and reuse the carbon. Then one would still use fossil carbon at the industrial plant from which CO₂ is captured, and emit CO₂ when kerosene made from these fossil carbon atoms is burned while flying. But because this fossil carbon is reused in synthetic kerosene, one would avoid the use of fossil kerosene and the emissions from the production of fossil kerosene - and therefore total emissions drop by a little more than 50%.

In this STORY we will describe both the production of synthetic kerosene with carbon from the ambient air as well as carbon from an industrial plant.

THERE ARE VARIOUS ROUTES TO MAKE SYNTHETIC KEROSENE

We will summarise the main principles how one makes synthetic kerosene here. If you really want to know the technical details, you can read the detailed report.

In essence one has to capture carbon dioxide (CO₂) from ambient air or an industrial plant, find water (H₂O) and require renewable electricity from a carbon neutral source like solar or wind. A possible route would then be to split the carbon dioxide into carbon monoxide + oxygen and the water into hydrogen + oxygen. There are various ways to do this. One way is to use an electrolyser that uses renewable electricity. Once you have carbon monoxide and hydrogen you can use exactly the same process that Shell uses in its Pearl Plant in Qatar to make synthetic kerosene.

There are other routes as well. The key idea is that it is possible to convert carbon dioxide, water and renewable electricity into synthetic kerosene. In the detailed report we explain the individual process steps that jointly form the renewable synthetic kerosene production chain. For each step we describe which organisations are active in this area, how the (chemical) process works, what the costs are now and what we may expect costs to be around 2030. Lastly, we describe how we use this information in the business case model we have developed to flexibly calculate almost every possible future outcome. This model is available as a separate electronic appendix to the detailed report. It allows you to make your own assumptions about the future and then calculate the price of renewable synthetic kerosene.

WE CAN CAPTURE ENOUGH CARBON FROM TATA STEEL TO FUEL ALMOST HALF THE NUMBER OF AIRPLANES AT SCHIPHOL AIRPORT IN 2016



To give you an idea for how much kerosene can be produced from the carbon emissions of an industrial plant, we consider the following scenario. We take Tata Steel in IJmuiden as an example, as well as Schiphol Airport's kerosene consumption in 2016. Tata Steel emits enough carbon atoms to fuel approximately 50% of the airplanes that fuelled at Schiphol Airport in 2016. Alternatively, if we capture the carbon atoms directly from the ambient air, there is no carbon limit and we can fuel any airplane we want at Schiphol airport. We would however also need more water and renewable electricity.

WE HAVE MORE THAN ENOUGH WATER IN THE AREA AROUND TATA STEEL/ PORT OF AMSTERDAM

If you want to produce a large volume of hydrogen you also need a large quantity of demineralised water. With the IJ nearby as well as the North Sea, water is not a limiting factor. We would need about 6,000,000 m³ of water. This is equal to roughly to 1% of water demand of all Dutch households, i.e. the yearly water demand of 77,000 households in the Netherlands, or 0.04% of the water usage of the Netherlands (including industry and agriculture).

WE ARE BUILDING LARGE AMOUNTS OF OFF-SHORE WIND NEAR THE COAST OF IJMUIDEN, SO WE ALSO HAVE "LOCAL" RENEWABLE ELECTRICITY

There are plans to build large off-shore wind farms near the coast of IJmuiden, which is also the location of Tata Steel's steel plant. Wind farms produce electricity in variable quantities depending on how hard the wind blows. TenneT (the Dutch high voltage grid operator) foresees that transporting that electricity (when supply from these wind farms is high and demand for electricity in Dutch society is low) to the rest of Europe will be quite expensive. Hence converting this peak

supply near IJmuiden into hydrogen could be an alternative to extending the high voltage electricity grid. Extending the high voltage grid would be expensive as well as possibly opposed by people who do not want more high voltage cables in their landscape.

The off-shore wind electricity produced near IJmuiden around 2030 would be enough to produce synthetic kerosene for approximately 1/3 of the airplanes that fuelled at Schiphol airport in 2016. Of course, this renewable electricity is not only there for the production of synthetic kerosene, and society's electricity demand may increase massively if various sectors electrify simultaneously. But it can be envisioned that a significant amount of electricity could become available for this use or that we increase the amount of wind farms even further for this application. Also, renewable electricity is not only produced near the coast of IJmuiden. There are also various other places on the North Sea producing electricity as well as on-shore wind farms and solar panels that produce renewable electricity during daytime.

THE INFRASTRUCTURE FOR KEROSENE IS ALREADY IN PLACE IN THE HARBOUR OF AMSTERDAM

Currently, the infrastructure to transport kerosene (pipeline to Schiphol Airport) and storage terminals are already in place in the Port of Amsterdam. Hence, if we produce the synthetic kerosene in the Port of Amsterdam/IJmuiden, we would not need a lot of extra infrastructure to secure supplies to Schiphol Airport. In fact, it would be a very good opportunity for regional embedding and integration of a novel cluster with a very wide reach.



WE CAN PRODUCE CARBON NEUTRAL KEROSENE, AND WE CAN PROBABLY AFFORD IT!

Although we now know that we can produce semi (up to just over 50% from waste gases of an industrial plant) or fully (up to 100% for direct air capture) carbon neutral synthetic kerosene, we do not know if we can also afford it. There are many uncertainties when exploring a pathway towards 2030. The main uncertainties turn out to be the price of crude oil and the price of renewable electricity. This is because the oil price is the main cost component for fossil kerosene and this price is very volatile. For the production of synthetic kerosene the main cost component is the price of renewable electricity. Although the price of solar and off-shore wind electricity has dropped quite considerably in the last few years, we do not know for sure how much further this cost reduction will go. Also we do not know what market prices will be if all sectors in society electrify simultaneously: in some scenario's there is a constant shortage of renewable electricity up until 2030 if this happens, in other scenario's where electrification is slower there is considerable excess electricity available.

A high price of fossil oil (for example 150 dollar per barrel, excluding taxes) makes fossil kerosene just as expensive as synthetic kerosene in our comparison in our base scenario. Similarly, a low price of renewable electricity (1.7 cents per kWh, excluding taxes) also puts synthetic kerosene at par with fossil kerosene. Of course, a combination of a slightly higher price of oil and a slightly lower price of electricity also creates parity (fossil kerosene and renewable synthetic kerosene having the same price). This could happen, for example, with oil at 120 dollar per barrel and electricity at 3 cents per kWh.

The high price of fossil oil can be a result of global supply versus demand and/or a fossil carbon tax, which is included in the price of the fossil kerosene. The low price of renewable electricity can be a result of high availability with low demand. As electricity supply and demand are instantaneous, this can also be the result of short moments where society demands less electricity and solar- and or wind electricity is abundantly available. For example, a windy sunny summer Sunday noon will have relatively high supply of solar- and wind electricity but low demand, while a Monday winter morning without wind might have low supply and high demand. Lastly, parity could be reached because synthetic renewable kerosene is subsidised.

WE SEE THAT, FOR EXAMPLE, THE FOLLOWING SET OF ASSUMPTIONS DELIVERS SYNTHETIC KEROSENE AT THE SAME PRICE AS FOSSIL KEROSENE BY 2030.

An oil price of 98 dollar per barrel (today's oil price is 63 dollar per barrel, the projection for 2030 80 dollar per barrel and in the recent past we have also seen prices as low as 40 or as high as 140 dollar per barrel)

A fossil CO₂ tax of 20 euro per tonne (in November 2017 the CO₂ ETS price was 8 euro per tonne)

An electricity price of 2.9 cents per kWh (currently the average price of electricity is 4 cents per kWh, with solar and wind electricity sometimes pushing the price towards 1 or 2 cents per kWh)

Oxygen, which is a by-product, is sold against production price

None of these assumptions seems very extreme. So the conclusion can be that we can quite possibly produce renewable kerosene at competitive or near competitive prices in the not so distant future.

AS A RESULT, NOT THAT MUCH WOULD HAPPEN TO THE PRICE OF A FLIGHT TICKET



Currently the costs of fossil kerosene in the ticket prices is estimated to be between 15 - 40%. The exact fraction depends on various factors, including airline, flight distance, airport and several other factors. According to our base scenario for 2030, synthetic kerosene would add 20 - 50 % to the price of the air ticket compared to a 'fossil kerosene' ticket. However, if price parity is reached (as in the previous example) tickets would of course cost exactly the same, irrespective of fuel choice.

AND THERE ARE ADDITIONAL SOCIETAL BENEFITS FROM SYNTHETIC KEROSENE

Besides achieving just over 50% CO₂ emission reduction (if we use the CO₂ produced by Tata Steel) or up to 100% emission reduction (if we use direct air capture), there are also a couple of other advantages to society as a whole.

First, carbon capture at Tata Steel and upgrading to kerosene reduces the import of fossil oil and avoids the costs of storing the CO₂ from the steel plant waste gases underground for a few thousand years. Either directly (in the price of steel) or indirectly (via subsidies on CO₂ storage), consumers would have to pay for these CO₂ reduction measures. Since imports of fossil oil/kerosene are reduced, geopolitical dependency would also reduce. This last argument is of course conditional on the idea that states which largely depend on oil income at present would find other ways to earn money, because otherwise geopolitical stress could increase if states like Russia or Saudi Arabia destabilise.

IF WE COMPARE SYNTHETIC TO BIO-BASED AND FOSSIL KEROSENE, THE FOLLOWING PICTURE APPEARS.

Indicator \ kerosene	Fossil	Bio (poplar)	Bio (rapeseed)	PtL (Tata)	PtL (DAC)
Water usage (m ³ /GJ)	0.03 - 0.07	112	165	0.04	0.04
Land usage (m ² /GJ)	0.02	58-213	208	0.03	0.04
Emissions (g CO ₂ /MJ)	87.5-89.1	37-73	54.9-97.9	40.8	0
Costs (€/l)	0.21-0.28	0.85-0.97		0.25-1.88	0.53-2.49

Overview Table 1: Comparison bio-based, fossil and synthetic kerosene.

Second, we would have a possibility to reduce the expansion of the high voltage grid. Since TenneT, the Dutch high voltage transmission system operator, is a 100% public company, this would avoid increasing our electricity bills and filling our landscape (unless high voltage cables go underground which is usually even more expensive).

Third, from an operational risk perspective, synthetic kerosene is preferred to fossil kerosene. Because the oil price and hence the fossil kerosene price is very volatile, airline companies went bankrupt when oil prices rose. This led to large costs, because people had to be flown back, future tickets were cancelled and people lost employment. As synthetic kerosene should have a less volatile price, it is a safer choice and companies as well as people are less likely to be hit by volatility effects.

If we take into account these first two aspects, price parity for society could be reached with an electricity price of 3.3 cents per kWh (instead of 2.9 cents per kWh) or an oil price of 88 dollars per barrel (instead of 98 dollar per barrel). We did not attempt to quantify the avoided long-term damages that the world would have to endure if we keep on adding CO₂ to the atmosphere.

SYNTHETIC KEROSENE HAS STRONG ADVANTAGES OVER BIO-BASED OR FOSSIL KEROSENE

Simply put, synthetic (i.e., PtL) kerosene require more than a thousand times less fresh water and arable land than two types of biomass that could be grown in the Netherlands. To put this in perspective, if we just want to fuel Schiphol Airport in 2017 with bio-based kerosene we would need to give up 0.5 - 1.8 times our Dutch arable land to produce it. Alternatives, based on waste materials such as used cooking oils might contribute as well, but are harder to scale up. Hence, upscaling bio-based fuels to cover the whole Schiphol operation based on national biomass and waste streams seems highly unlikely. Going beyond the Netherlands, it seems bio-based kerosene can make a limited contribution to overall aviation fuel demand at best, if feedstock demand is not to conflict with food production and water demand.

Emissions from fossil kerosene are most significant, although crop-based kerosene has about half to slightly greater emissions, depending on source and calculation method. Synthetic kerosene from waste gases emits just below half of fossil kerosene, and this quantity is not subject to as much uncertainty as that of bio-based kerosene. Only when kerosene is produced from carbon from the air, emissions can get close to zero.

If we look at costs lastly, we see that local bio-based kerosene costs are currently greater than fossil kerosene costs, even when the oil price is at 140\$ per barrel. The cost uncertainty for fossil and synthetic kerosene is much greater. Synthetic kerosene can be much more expensive, but also significantly cheaper, than fossil-kerosene depending on how various factors work out in the near future.

CONCLUSION: IT IS TIME TO CONSIDER ACTUAL PRODUCTION OF SYNTHETIC KEROSENE

Synthetic based kerosene from carbon capture at Tata Steel IJmuiden or direct air capture, off-shore Dutch wind electricity, and Dutch water could be a reality around 2030. It is very likely that it can be done, and we can afford it if we assume modest changes to current prices. Furthermore, it seems this is the best option available to start making aviation carbon neutral before 2050. And last but not least, it is an excellent opportunity to develop a strong cluster that increases economic and industrial activity around the Port of Amsterdam, and could make Schiphol (one of) the first airport(s) in the world to be supplied with renewable kerosene.

Hence, we propose that the consortium partners jointly fund and build, together with the Dutch government, a modular pilot factory that is 1,000 times smaller than the 9 Megaton CO₂-equivalent

factory we would need to capture all carbon from Tata Steels waste gasses and which would provide fuel for approximately 50 % of all airplanes fuelling at Schiphol Airport. We estimate that the investment involved for this plant with a 9 kiloton CO₂-equivalent capacity would be around 14 - 19 million euro's (excl. financing) for a fully working process - although these cost estimates are best looked at by an experienced engineering firm. This estimate includes both carbon capture at Tata Steel plant from a small waste gas stream and a direct air capture unit, an electrolyser and all units necessary to combine CO₂ and H₂ and synthesise kerosene.

This set-up would allow the consortium to test various routes and validate the quality of kerosene produced. Once this first phase is successful choices will have to be made whether and how to scale up. Along the way we can also come to a conclusion on how best to allocate the emission reductions to the consortium partners, especially Tata Steel and KLM. The consortium can also evaluate the likelihood of other parts of the world producing hydrogen and or synthetic liquids from renewable sources at a lower price, and if these countries would be able to start to export to Europe.

Starting the decision process in 2018 to plan a 9 kiloton production process for synthetic kerosene will bring the Netherlands among the first movers in this direction. In an economy that will increasingly use intermittent renewable electricity and electrolyses to produce hydrogen, there will be many learning opportunities in our ambition to become carbon neutral by 2050.



DETAILED REPORT

INTRODUCTION

Quintel and Kalavasta have explored many pathways to achieve a carbon neutral world. Together with our partners we have made considerable progress in developing and communicating such pathways for various sectors of society. This is the first time that we focus our attention on the aviation sector.

The aviation sector is central to many commercial, industrial and recreational aspects of our lives, and represents a large and rapidly expanding segment of the modern-day energy and carbon expenditure. Beginning to mitigate the climate impact associated with aviation is therefore a daunting task which requires bold and out-of-the box strategies for all of the associated stakeholders.

We are very enthusiastic and proud that a group of frontrunners of these industrial stakeholders has agreed to explore with us, for the first time as a consortium, the feasibility of pathways to a carbon neutral aviation sector.

MOTIVATION

International aviation (as well as navigation) has a rather special status as an energy consumer – fuel is not taxed or mandated like it is in other sectors. These are perhaps some of the reasons international aviation has not received as much attention as other sectors in the climate discussion. Direct emissions from aviation are more than 2% of worldwide emissions¹. However, the sector seems set to expand significantly, while there is not really a serious alternative in terms of technology or fuel at hand. It is therefore high time to investigate how aviation could be made carbon neutral.

AVIATION GROWTH, EMISSION TARGETS

Various aviation associations and aviation industry experts have indicated that they expect worldwide aviation to grow by 4 - 5% per year until 2037, much in line with aviation growth in the past 20 years. The International Air Transport Association (IATA) expects a compound average growth rate (CAGR) of 3.7% annually, resulting in a doubling of global demand in 20 years; Europe's rate specifically is estimated at 2.5%². The Airports Council International (ACI) estimates in its World Airport Traffic Forecast 2016-2040 a larger growth of 5.2% a year, with Europe at 3.7%³. The International Civil Aviation Organisation (ICAO) expects a CAGR of 4.5% for the 30-year period from 2012 to 2042, with Europe at 3.3%⁴. For the next 20 years, Airbus expect a 4.4%/y global air traffic growth, with a rate of 3.4% in Europe⁵.

At the same time, efficiency gains were and are predicted to be around 1.3% per year. Historically, from 1968 to 2014 fuel consumption of new planes dropped by a compound annual rate of 1.3%⁶. It should be noted that this rate has not been constant, and appears to slow down. Boeing estimates efficiency gains at 1.5%/y until 2020; increases in CO₂ emissions beyond that year are supposed to be offset against non-aviation related measures⁷. It is unclear whether it thinks these efficiency improvements will continue after 2020.

Therefore, combining aviation traffic growth projections and expected efficiency improvements, we may expect an overall annual growth of 2.5 - 3.5% in aviation and associated kerosene use in Europe. If we extrapolate these numbers from 2005 (the reference year the aviation industry uses for

CO₂ emissions) to 2050 (the year in which we strive to have a carbon neutral global society) the amount of kerosene consumed annually would have grown by a factor of 3 to 5. With respect to the present year (2017), global aviation traffic would grow by a factor 2.3 to 3.2.

It is conceivable that efficiency gains will flatten, which means this number may in fact be larger - and the growth factor w.r.t. 2017 be as high as 5.

In 2009, the International Air Transport Association (IATA), encompassing the operators of 93% of all flights worldwide, set the goal to halve CO₂ emissions by 2050 with respect to 2005⁸. Rather than a predicted growth factor of 3 to 5 as obtained from the business-as-usual extrapolation, the industry aims for a factor 0.5 reduction of CO₂ emissions. This aim and prediction are a factor 6 to 10 apart. To put this in another perspective: if the rest of society reduces its emissions by up to 95% by 2050 (as set out by the European Union) and aviation increases by a factor 5, it will make up about two thirds of global emissions in 2050.

A recent PhD thesis investigated tourism's impact on CO₂ emissions and possible policies to mitigate its impact. It does not (extensively) consider alternative fuels or technologies, but focuses on financial and political means to achieve this. It highlights the virtual impossibility of taming CO₂ emissions increase due to aviation growth - a growth reduction a.o. requiring steep efficiency gains, an extreme CO₂ tax, expensive tickets, and development of high-speed rail alternatives⁹. It is unlikely these strong requirements will be met, and even more uncertain whether they would in fact significantly reduce CO₂ emissions. It seems like we need a different solution, one that is not just political or financial. What this situation thus calls for may be a technical measure - i.e. a near-zero emission solution.

¹ European Commission (2017): *Reducing emissions from aviation*.

² IATA (2016): *IATA Forecast Passenger Demand to Double Over 20 Years*

³ ACI (2016): *World Airport Traffic Forecasts 2016-2040*

⁴ ICAO (2016): *ICAO Long-Term Traffic Forecasts*

⁵ Airbus (2017): *Global Market Forecast. Growing Horizons 2017/2036*

⁶ ICCT (2015): *Fuel efficiency trends for new commercial jet aircraft: 1960 to 2014*.

⁷ Boeing (2017): *Current Market Outlook. 2017-2036*

⁸ IATA (2009): *Bold Industry Commitment on Environment*

⁹ P. Peeters (2017): *Tourism's impact on climate change and its mitigation challenges. How can tourism become 'climatically sustainable'?*

CURRENT TECHNOLOGY, ALTERNATIVE FUEL

In light of national and international ambitions to significantly cut greenhouse gas (GHG) emissions, virtually every sector is facing the same challenge of becoming (nearly) carbon-neutral. Conceptually, this can be 'solved' by making the existing system run a carbon neutral energy carrier, or, if that is not possible, develop a new technology which allows for this. In many sectors, the second route, which often implies electrification, is chosen.

In aviation, developing such technology is much harder. Current electric planes can carry 8 to 10 passengers for about 1 hour flight time; both the range and passenger capacity have to be increased, independently, and experience shows this becomes increasingly difficult¹⁰. Siemens' goal is to have a hybrid-electric plane capable of transporting 50 - 100 passengers for 1,000 km in 2035¹¹. Wright Electric, in partnership with EasyJet, aims to have developed a commercial plane which can fly for 500 km by the end of the next decade, but does not disclose how many people this plane could carry¹².

Even if these goals, widely regarded as ambitious, are achieved, electric planes will probably account for a very small part of passenger kilometres (kms) for three reasons. One, electric planes of the size expected would be able to carry fewer passenger than planes on kerosene, meaning that the latter would generate more passenger kms on the same routes. Second, electric planes with the range expected would be limited to short-haul flights, meaning planes on kerosene would have a 100% share of long-haul flights. Third, when these electric planes appear in the market, they will not directly replace the existing fleet. Planes on kerosene have a lifetime that is limited by the engine, which typically runs for 30,000 cycles (take-off and landing) which normally amounts to about 30 years¹³. This means that in the 2030s, when Siemens and Wright Electric think they can produce the first (small) commercial (hybrid-)electric planes, these planes on kerosene will mostly likely stay active for many years still, as it would be uneconomical to replace them right away. Based on the projections and thoughts above, we may expect electric planes to have a 0% share in long haul and a marginal share in short haul passenger kms in 2035.

¹⁰ VPRO Tegenlicht (2017): *Groene vliegtuigpioneers*

¹¹ VPRO Tegenlicht (2017): *Groene vliegtuigpioneers*

¹² *The Guardian* (2017): *EasyJet says it could be flying electric planes within a decade.*

¹³ Source: Rob Duivis, KLM

ALTERNATIVE FUELS

The challenge, therefore, is to make carbon neutral kerosene which can be used with current plane and engine technology. The reason we look for kerosene that is 'carbon neutral' rather than 'climate neutral', is that non-carbon emissions from planes have effects that are not yet fully understood, but generally believed to have a net global warming effect¹²³. Two contenders exist: bio-based and renewable synthetic (or Power-to-Liquids (PtL)) kerosene. Bio-based kerosene is kerosene made from organic, harvested feedstock. PtL concerns the production of hydrocarbons from water (H₂O) and carbon dioxide (CO₂) or carbon monoxide (CO). If this is done with renewable energy, the resulting kerosene is renewable. When we speak of synthetic kerosene or PtL kerosene in this report, we refer to renewable synthetic kerosene. The carbon neutrality of this kerosene depends on the source of carbon, which is something we will discuss at greater lengths soon.

Although there are two alternatives for fossil kerosene, bio-based and synthetic kerosene, we will not investigate bio-based kerosene for several reasons.

First, kerosene produced from biomass that can be grown in the Netherlands requires several orders of magnitude more water than synthetic kerosene¹⁴. This may put stress on existing fresh water reservoirs, especially in areas where water supply is already critical.

Second, kerosene produced from biomass that can be grown in the Netherlands also demands more than 1,000 times the amount of land required for synthetic kerosene production, and further demands this land to be arable land¹⁵. The latter point means that growth of feedstock for fuels competes with the growth of (local) produce and bio-based materials.

Third, bio-based kerosene is not necessarily carbon-neutral¹⁶, which is part of the criterion we defined. Biomass drying requires heat, creating and maintaining farmlands and biomass gasification emit CO₂, which does not end up in the resulting kerosene. Although bio-based energy carriers are carbon-neutral in carbon accounting, they are not simply carbon-neutral in practice. CO₂ emitted is only taken up again over a long-term cycle, provided there is a sufficient number of trees and plants (i.e., more generally, CO₂ consumers).

¹⁴ Umwelt Bundesamt (2016): *Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

¹⁵ Umwelt Bundesamt (2016): *Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

¹⁶ Umwelt Bundesamt (2016): *Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

Second and third generation biofuels partially address these limitations, but as of yet do have other disadvantages. Second generation biofuels such as biofuels from used cooking oils do not compete with food production, but still require large quantities of water and are difficult to scale up. The Netherlands produce just short of 0.2 Megaton (Mt) of oils and fats, import 11.8 Mt of oil and fats (of which 0.2 Mt¹⁷ used cooking oil) and export some 6 Mt. Currently, about 1.5 Mt is used for biofuel production (mostly biodiesel, and mostly not second generation) and 0.004 Mt oils and fats are recycled in total - making the total used oil supply 0.204 Mt¹⁸. With this quantity, we can produce a fraction of Schiphol's current yearly kerosene consumption (3.6 Mt) - and less for future consumption. Therefore, it seems safe to say we cannot produce substantial quantities of kerosene from used, second generation oils. Third generation biofuels (algae) have received a lot of attention, but as of yet and for the foreseeable future do not make a sustainable nor a commercial business case¹⁹.

Lastly, combining the previous three points, it seems difficult to envision a future where large quantities of kerosene are produced through scaled-up bio-based kerosene production. Not only do the three points limit that, but also do seasonality and required infrastructure hinder scaling of bio-based

kerosene production. This report will therefore focus on synthetic kerosene, but will also feature a comparison with bio-based and fossil kerosene, using literature values.

CIRCULAR ECONOMY

An interesting feature of synthetic kerosene is that it can fit very well in a circular economy. If CO₂ is obtained from the ambient air and released again upon synthesis and combustion, we have effectively created a short-term carbon cycle. In addition, there is a hydrogen cycle: we convert water into hydrogen and oxygen, then use the hydrogen to produce kerosene, and burn kerosene (i.e. react with oxygen) to release water (along with CO₂, as mentioned before). These cycles are depicted in Figure 1. This illustrates another benefit synthetic kerosene has over bio-based kerosene - it results in a short-term, rather than a long-term carbon cycle. Using CO₂ from the ambient air thus results in an indefinite recycling scheme. If CO₂ is obtained from waste gases, the kerosene production from such gases can be considered upcycling.

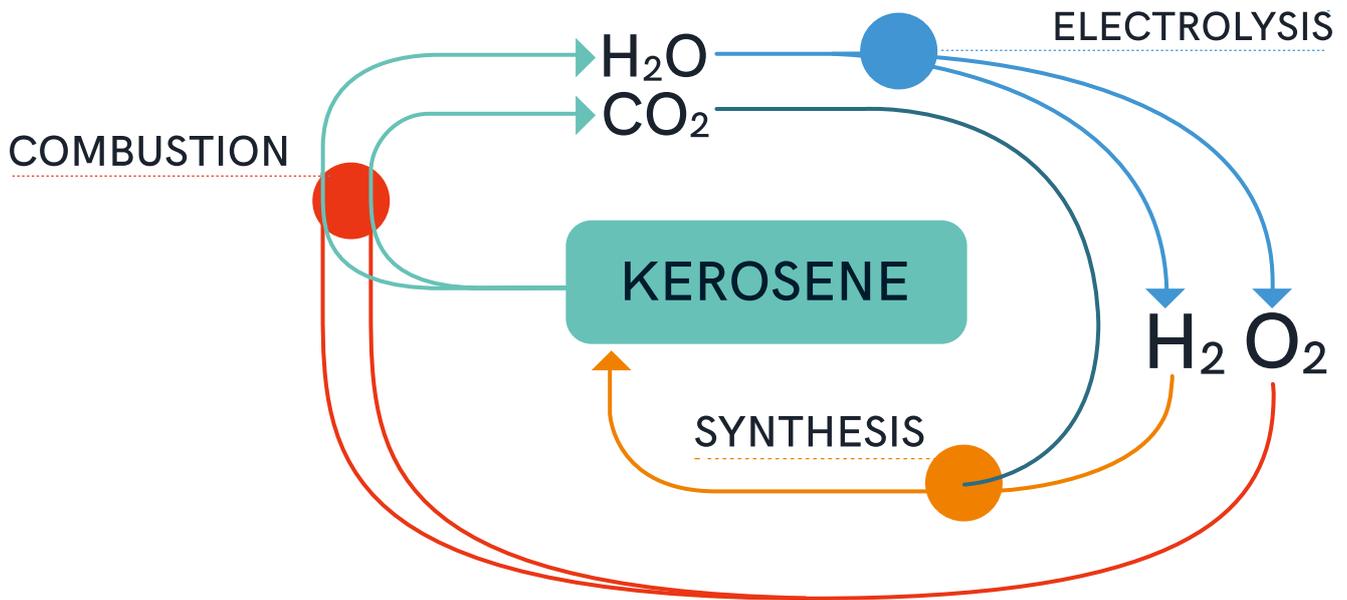


Figure 1: Carbon and hydrogen cycle in synthetic kerosene production and utilisation, with the ambient air as a CO₂ source.

¹⁷ MVO (2014): *The Dutch Oils and Fats Industry - An International and Sustainable Chain*

¹⁸ MVO (2014): *The Dutch Oils and Fats Industry - An International and Sustainable Chain*

¹⁹ *The Conversation* (2017): *Algal biofuel production is neither environmentally nor commercially sustainable*

STRUCTURE

In this report, we will focus on the business case of synthetic kerosene production in the Netherlands in 2030. In the next chapter, we will discuss several synthetic kerosene production processes in detail. This serves as a technical introduction to the topic as well as a setup for business case modelling later. The chapter thereafter, we zoom in onto the North Holland area in the Netherlands, a location with high potential for synthetic kerosene production. We discuss the current infrastructure and stakeholders as well as how production would fit in. In the succeeding chapter, we develop and analyse several scenarios for synthetic kerosene production in this area. We first describe how we define our system, develop a reference scenario, perform an impact/uncertainty analysis of key parameters and construct a scenario in which price parity is achieved between fossil and synthetic kerosene production. Finally, in the last chapter, we present our conclusions - followed by a section on how we could proceed to actually develop a synthetic kerosene production plant in the Netherlands.

PROCESS

In this section we will discuss various production pathways in detail. To produce kerosene, which is a mixture of hydrocarbons fractions (C_xH_y), we need two building blocks: a source of carbon and a source of hydrogen. Acquiring these elements concerns step 1 (hydrogen production) and step 2 (carbon capture) of the process. Once hydrogen and carbon are obtained there are two main pathways to then produce kerosene, distinguished by their intermediate products. There is the Fischer Tropsch (FT) pathway, where syngas (a mixture of CO and H₂) is the intermediate. Another route is the alcohol pathway, where an alcohol (e.g. methanol) is the intermediate. For the Fischer Tropsch pathway, it is necessary to first produce CO, if this was not obtained directly by means of carbon capture in step 2. The entire production chain is shown in Figure 2.

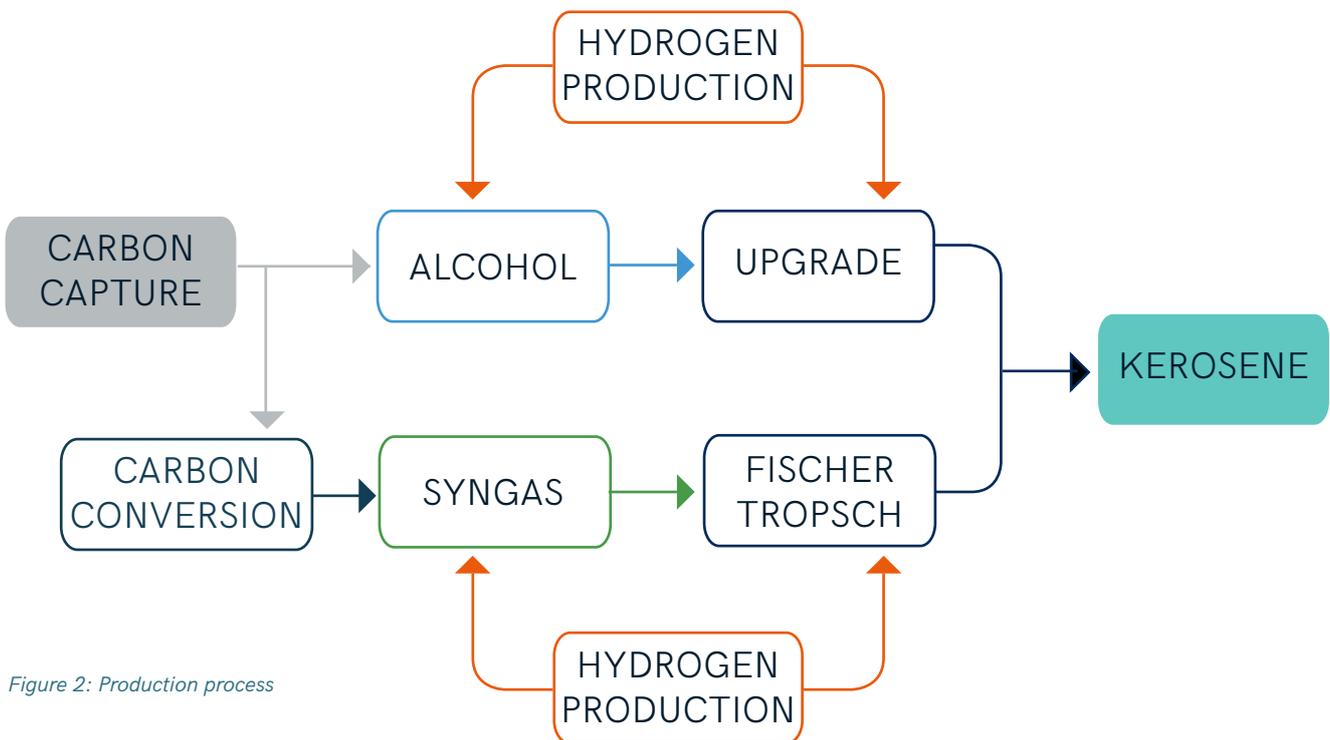


Figure 2: Production process

In various plants and via various processes it has already been demonstrated that it is possible to produce synthetic fuels from CO₂ and H₂. In 2015, members of the European SOLAR-JET project managed to run the entire kerosene production chain for the thermochemical route²⁰. The follow-up project, SUNtoLIQUID, aims to scale up this process. In Finland, a public-academic project named Soletair managed to run the entire process via the FT route in a shipping container²⁰. The German company Sunfire produces 1 barrel of synthetic crude oil in its demonstration plant; this 'blue crude' can then be cracked and refined via conventional refinery processes to gasoline, diesel and kerosene²². Nordic Blue Crude, a start-up, has already committed itself to construct an 8 kt/y factory operating at 20MWe due to operate in 2020, and an 80 kton/y factory set for 2023, scaling Sunfire's process²³.

In the next subsections we will discuss the individual process steps in more detail. We will follow a uniform structure to describe each step. First, we will introduce the process step and discuss a selection of current initiatives and organisations working on it. Then we dig deeper into the technology and chemistry, followed by the current techno-economics and an estimate of the techno-economics in 2030. Lastly, we wrap up how we model this technology for the business cases discussed in later sections.

HYDROGEN PRODUCTION

INTRO

Hydrogen is not only the most abundant element in the universe, but also a very fundamental building block in the chemical industry. Some believe it may play a very integral role in the future energy system, as it is considered an interesting carrier for energy storage, in (long-haul) transport, power generation and more recently even in heating in the built environment. Worldwide hydrogen production mainly consists of steam methane reforming (SMR), which requires (natural) gas as a feedstock and emits CO₂. A century-old alternative is electrolysis, which concerns the splitting of water into hydrogen and oxygen. This process requires more energy, but if the electricity supplied is renewable, so is the resulting hydrogen. With the development and scale up of wind and solar electricity capacity, the cost of renewable hydrogen production is coming down rapidly - mainly as a result of lower renewable electricity prices, but also because electrolyser prices are dropping. Hence, a way is paved for this renewable energy carrier.

²⁰ D. Marxer et al. (2015): *Demonstration of the Entire Production Chain to Renewable Kerosene via Solar Thermochemical Splitting of H₂O and CO₂*. *Energy Fuels* 29(5) 3241-3250

²¹ Soletair (2017): *Technical Specifications*.

²² Sunfire (2017): *First Commercial Plant for the Production of Blue Crude Planned in Norway*.

²³ Sunfire (2017): *First Commercial Plant for the Production of Blue Crude Planned in Norway*.

INITIATIVES AND ORGANISATIONS

An electrolysis plant nowadays is much smaller in capacity than a SMR plant, but the technology scales rapidly. Siemens is a large producer: it supplied three 2 MW electrolysers for the power-to-gas project Energiepark Mainz in 2014 - the largest plant of its kind at the time²⁴. More recently, ITM Power announced it would install a 10 MW electrolyser at Shell's Rheinland refinery in Germany²⁵. Other players in the MW scale market include Hydrogenics and Proton OnSite. Most of these have already designed plants in the >10 MW scale, utilizing the technology's modularity.

PROCESS

The chemical reaction of water splitting is the following:



This is a strongly endothermic process. At 100% efficiency, it would still require almost 40 kWh to produce 1 kg of hydrogen. There are various types of electrolysers. Alkaline electrolysis is the oldest and generally cheapest technology, but has a limited efficiency. Proton Exchange Membrane (PEM) is younger and benefits from a very high response rate and increased efficiency. Solid oxide electrolysers (SO) operate at a higher temperature, therefore requiring a smaller enthalpy change - efficiencies are typically highest here. Although efficiency gains are there, we choose to work with PEM technology over SO technology for its fast ramp-up time, allowing us to follow the fluctuating supply of electricity from wind and solar flexibly. Electrolysers produce H₂ at a sufficiently high pressure for the downstream processes which require an input of approximately 20 bar. Hence further energy consuming compression steps are not necessary for our purposes. We consider the technology readiness level of this process step to be 9, with the SO technology at 7.

CURRENT TECHNO-ECONOMICS

The system efficiency of the current 1.25 MW Siemens SILYZER 200 electrolyser is approximately 65-70%. H₂ is then delivered at 99.9-99.99% purity and at a pressure of up to 35 bar, which is more than sufficient for our subsequent conversion processes. Siemens claims a PEM electrolyser lifetime of > 80,000 operational hours, such that the lifetime is longer in infrequent operation (low Full Load Hours (FLHs)) and shorter if in frequent or constant operation (high FLHs)²⁶. This is based on operational experience. After 80,000+ hours of operation, the stack (which makes up 15% of future investment costs), has to be replaced. Lifetime of other components is much longer, and we consider the rest of the electrolyser to have a

²⁴ M. Kopp et al. (2016): *Operational and economic analysis of the worldwide largest Power-to-Gas plant with PEM electrolysis*.

²⁵ ITM Power (2017): *10 MW refinery hydrogen project with Shell*.

²⁶ This paragraph is based on information disclosed by Siemens at the Oil and Gas Reinvented Conference, held on 9/11/2017 at the Shell Technology Centre Amsterdam

lifetime of 30 years. Siemens also reported that even after 70k hours of intermitted operation time, no additional degradation was observed, indicating that its PEM electrolyser can truly be used flexibly with its ramp up times (to 100%) of less than 10 seconds.

ITM Power has similar experience: their stack degrades with roughly 1% a year, while still producing the same quantity of hydrogen, meaning that electricity consumption increases by about 1% a year. Typically, this means the stack is replaced after roughly 10 years, or whenever this is most economical. The stack, currently, costs no more than 40% of total investment costs, and this number is expected to decrease. Lifetime of other components is also significantly longer, estimated at 20 years. ITM also reported that its PEM electrolyser is capable of switching from 50% capacity to standby or full capacity in 1 second. Lastly, it delivers H₂ at 20 bar pressure and at 30 bar in future models; O₂ is delivered at atmospheric pressure and might have to be dried if one plans to use it. Investment costs of current technology (at the MW scale) are estimated to be €800/kW.

FUTURE TECHNO-ECONOMICS

ITM Power reports a 77% to 86% efficiency for its PEM electrolysers, depending on operating conditions and whether heat is recovered²⁷. Investment costs are estimated to be €500/kW (at 100 MW scale) in 2024 according to ITM projections²⁸; yearly O&M costs 3% of Capital Expenditure (CAPEX). Siemens projections are €300/kW in 2027 at a 1 GW scale.

It is worth noting that many electrolysers use Iridium for the catalyst at the anode. Worldwide mining capacity is very low and reserves are believed to be very scarce. This means that, all things being equal, on the long-term the quantity of Iridium used per electrolyser should be vastly decreased or a different catalyst should be used, if the CAPEX is not to be affected negatively. Alternative catalysts do exist²⁹.

IMPLEMENTATION

In our modelling, we consider an 80% efficient (HHV, so requiring 49 kWh to produce 1 kg of hydrogen) PEM electrolyser with investment costs of €300/kW. We assume the stack accounts for 15% of total investment costs and is replaced every 10 years, while the rest of the system has a lifetime of 30 years. Yearly operating and maintenance (O&M) costs are 3% of CAPEX. Full-load hours (FLHs) are identical to those of the renewable electricity production plants which provide the electricity required.

²⁷ ITM Power (2017): *Scaling Electrolysis to 100 MW*

²⁸ ITM Power (2017): *Scaling Electrolysis to 100 MW*

²⁹ K. Meier (2014): *Hydrogen production with sea water electrolysis using Norwegian offshore wind energy potentials*. *Int J Energy Environ Eng*, 5, 104-112.

³⁰ Among others: US Navy (2010): *The Feasibility and Current Estimated Capital Costs of Producing Jet Fuel at Sea Using Carbon Dioxide and Hydrogen*

³¹ Xprize (2014): *Fuel from Seawater? What's the Catch?*

CARBON CAPTURE

The envisioned process requires a source of carbon. We will consider 3 possible sources: a CO₂ point source, a CO point source and the ambient air. We will not look into CO₂ capture from seawater, which the US Navy studied³⁰, as it requires enormous amounts of seawater, similar energy requirements to process it, results in methane emissions and, at scale, poses serious dangers to aquatic life³¹. All capture processes are based on the principles of adsorption, but the sorbents, process design and operating conditions differ. CO₂ and CO point sources are concentrated flue gases containing a significant amount of CO₂ and CO, respectively. Direct Air Capture (DAC), on the other hand, concerns adsorption of CO₂ from the ambient air. We will treat these sources in order of technology readiness.

CO₂ POINT SOURCE

INTRO

At many industrial and power plants, waste gases are emitted, typically mainly consisting of CO₂. Preventing these concentrated streams from entering the atmosphere would not only reduce emissions, but also provide us with a source of carbon and the choice to store or utilise it. For a synthetic kerosene production process, this CO₂ could serve as the necessary carbon building block. Although this CO₂ turned kerosene would ultimately be combusted again, it nonetheless reduces the demand for fossil kerosene - and the corresponding emissions. The kerosene produced is therefore not completely carbon neutral, but saves slightly more than 50% of emissions compared to fossil kerosene.

INITIATIVES AND ORGANISATIONS

Concentrated carbon capture is more process than product; they are typically engineered to specification in an existing plant. The global CCS institute compiles a list of large-scale carbon capture projects which can be accessed freely from their website. Most existing projects use industrial separation, while some perform post-combustion capture at power plants. Capture capacities are typically around 1 Mt per year, with the largest being 8.4 Mt per year.

PROCESS

There exist various CO₂ separation techniques, but adsorption is most common³². In a reactor CO₂ is adsorbed onto the solvent and in a subsequent reactor the solvent is regenerated with heat and the CO₂ released. Afterwards, the CO₂ stream is cleaned (and, depending on conditions, dried) and compressed for transport and storage or utilisation. Exact process conditions depend on the solvent, but are typically low temperature (40 °C) and ambient to intermediate pressure. Monoethanolamine (MEA) is one of the most common solvents; it has high efficiency and selectivity, but also degrades and may form toxic products³³. Newer amine solvents with lower energy requirements and fewer drawbacks are being researched. Besides chemical adsorption, physical adsorption such as Selexol is also an option. We consider the technology readiness level of this step to be 9, as large-scale post-combustion capture systems are already operational.

CURRENT TECHNO-ECONOMICS

Current techno-economics are based on estimates, as there is limited data, let alone open data. Moreover, they depend strongly on what type of plant CO₂ is captured from – a power plant which emits nearly pure CO₂ is quite different from flue gases from a steel plant that are used downstream. With some foresight to the specific context we will consider later (see chapter 'Zooming in'), we will look at the techno-economics of CO₂ capture from a steel plant.

For chemical adsorption such as MEA, capital cost are estimated to be about 80 €/t CO₂ capture capacity/y) with yearly O&M costs at 5% of CAPEX, for a capture plant with a lifetime of 20 years delivering 99.9% pure CO₂ with a 99.9% yield³⁴. For a typical adsorption process with MEA, electricity consumption is 55 kWh/t CO₂ for the capture process and 115 kWh/t CO₂ for compressions to 110 bar; low pressure steam consumption of 3.2 GJ/t CO₂ is needed to regenerate the solvent³⁵. At current Dutch spot prices, this evaluates to about € 35 /t CO₂ if steam has to be generated. In a different study, costs are estimated to be 60 euro/ t CO₂ if steam is to be generated and as low as 25 euro/ t CO₂ if waste heat can be supplied fully³⁶. If physical adsorption is used (e.g. Selexol), there is no regeneration need and heat requirements are zero, while electricity requirements are about 240 kWh/t and investment costs 180 €/ (t CO₂/y) ³⁷.

³² IEA (2012): CO₂ abatement in the iron and steel industry.

³³ P. Luis (2016): Use of monoethanolamine (MEA) for CO₂ capture in a global scenario: Consequences and alternatives. *Desalination* 380, 93-99

³⁴ Kuramochi (2011): CO₂ capture in industries and distributed energy systems: Possibilities and limitations

FUTURE TECHNO-ECONOMICS

The techno-economics detailed in the section above are in fact largely 'future techno-economics', as they do not describe current capture plants. One way in which long-term future techno-economics might differ is in the sorbent. New sorbent with lower regeneration requirements and fewer drawbacks are being developed. We may estimate future solvents to have electricity requirements of 140 kWh/t CO₂ and heat requirements of 2.2 GJ/t CO₂³⁸.

IMPLEMENTATION

In our modelling, we consider a CO₂ capture plant which uses physical adsorption with investment costs of €180 / (t CO₂/y), yearly O&M costs of 5% of the CAPEX and 20-year lifetime. 99.9% of CO₂ in the flue gases is captured. For our purposes, we compress CO₂ to 20 bar which is sufficient for later processes. This process electricity requirements of 195 (for pumps) + 45 (for compression) = 240 kWh/t CO₂ and zero heat requirements. The process is expected to operate continuously, to the extent that the plant it captures carbon from is expected to do so.

CO POINT SOURCE

INTRO

A fundamental principle in (process) chemistry is that one would like to work with those building blocks, that are converted the easiest and/or require the least energy to be converted to the desired product. From that perspective, starting FT kerosene synthesis with CO₂ is not optimal; it has to be converted to CO first. With a CO point source, this step can be skipped. Such sources are not abundant, but can be found, especially in steel plants. A downside is that CO is considered a more useful molecule than CO₂, so it typically already serves some purpose, although this is usually combustion for heat or electricity generation. Since it can have a higher value, academics and engineers alike have looked into separating CO (from flue gases) for synthesis purposes. This is considered more difficult than CO₂ capture, as CO molecule size is similar to N₂, but attempts have been successful.

³⁵ IEA (2012): CO₂ abatement in the iron and steel industry.

³⁶ Kim et al. (2015): Economic process design for separation of CO₂ from the off-gases in ironmaking and steelmaking plants. *Energy* 88, 756-764

³⁷ IEA (2012): CO₂ abatement in the iron and steel industry.

³⁸ IEA (2012): CO₂ abatement in the iron and steel industry.

INITIATIVES AND ORGANISATIONS

In the 1980s KTI developed the COSORB and COSORB II process, which is able to separate CO from a variety of industrial plants such as steam reformers and steelworks. It has been implemented in various sizes, up to 5,500 Nm³/h recovered CO flows³⁹. An improved version is licensed as the COPURE process and is developed and implemented by R.C. Costello & Associates⁴⁰. In China, Peking University affiliated Pioneer is strong in CO separation. They have built many PSA-CO (CO separation) plants across the world, including the world's largest plant with a CO flow of 20,000 Nm³/h⁴¹.

PROCESS

The COSORB (II) process works by complexation and de-complexation of CO in CuAlCl₄ dissolved in toluene. It is claimed to yield 99% of CO at 99+% purity; presence of H₂, CO₂ and N₂ does not pose a problem⁴². PKU Pioneer uses pressure swing adsorption, which drives adsorption with a pressure increase and desorption with a pressure reduction and would require removal of CO₂ (if present in waste gases) prior to CO separation^{43,44}. Pioneer's PSA technology is claimed to recover up to 95% of CO at 99.99% purity⁴⁵. As both techniques have been implemented in many different large-scale plants, we consider the technology readiness level to be 9.

CURRENT TECHNO-ECONOMICS

Fixed costs (investment and O&M) including straight depreciation for the PSA process amount to about €18/t CO⁴⁶. The original paper for the COSORB process details investment costs, but those are likely to be outdated. We therefore assume the same fixed costs as for the PSA process, i.e. €18/t CO. The utility requirements for the COSORB process are 0.2 - 0.5 kW/Nm³ of CO electricity and 1.0 MJ/Nm³ CO (i.e. 877 MJ/t CO), where the electricity range depends on the climate⁴⁷. The PSA process requires 0.3848 kWh/Nm³ CO (i.e. 340 kWh/t CO) electricity and 0.0315 kg/Nm³ CO steam⁴⁸. This steam is low temperature steam and waste heat could be used.

The numbers above do not include compression costs. If we assume CO compression has the same electricity requirements as CO₂ compression on a molar basis, CO₂ compression to 20 bar can be achieved for 45 kWh/t CO₂ = 45 kWh / (1 t / 44 ton/Mmol) = 1,980 kWh/Mmol, so for CO 1,980 kWh / (1 Mmol * 28 t/Mmol) = 71 kWh/t CO. Moreover, one should also account for the value of CO that is captured, if it is currently used. Although not part of the technology, it is part of the techno-economics in a business case.

³⁹ KTI (1988): *The Use of COSORB II to Recover High Purity Carbon Monoxide from a Feed Gas*. AICHE Summer Meeting.

⁴⁰ R. Costello & Associates (2017): *COPure*

⁴¹ PKU Pioneer (2017): *PSA-CO Plant*

⁴² KTI (1988): *The Use of COSORB II to Recover High Purity Carbon Monoxide from a Feed Gas*. AICHE Summer Meeting.

⁴³ J. Arvola et al. (2011): *Combining Steel and Chemical Production to Reduce CO₂ emissions*. *Low Carbon Economy* (2) 115-122.

⁴⁴ W. Uribe-Soto et al. (2017): *A review of thermochemical processes and technologies to use steelworks off-gases*. *Renewable and Sustainable Energy Reviews* 74, 809-823

FUTURE TECHNO-ECONOMICS

Since CO capture technology has been in development for several decades already, we do not expect the future techno-economics to be very different from the current techno-economics.

IMPLEMENTATION

In our modelling, we consider a CO capture plant with fixed costs of €18/t CO, and a 10-year lifetime. For our purposes, we compress CO to 20 bar which is sufficient for later processes. The process has electricity requirements of 340 + 71 = 411 kWh/t CO and heat requirements of 0.88 GJ/t CO. It is assumed to capture 98% of CO in the flue gas. The process is expected to operate continuously, to the extent that the plant it captures carbon from is expected to do so.

DIRECT AIR CAPTURE (DAC)

INTRO

In the past decades we have both made and seen the CO₂ concentration in air increase, to a point it is threatening the existence and functioning of parts of our world, infrastructure and species, including ourselves. Some believe that to limit further disturbance, we could capture carbon and utilize (CCU) it, as for instance in this process via capture of waste gases listed above. This creates more value for carbon, but is limited to single-time recycling - once kerosene made from point source carbon is combusted, the resulting CO₂ enters the atmosphere. To take things one step further, there is an option where we can recycle CO₂ indefinitely, and this would require Direct Air Capture (DAC). DAC yields negative emissions as we remove CO₂ from the atmosphere. After that, kerosene synthesis and utilisation results in positive emissions, but the net CO₂ addition to the atmosphere is close to zero under the assumption that the process is powered by solar and wind electricity. In fact, we are creating a short-term carbon-cycle. Moreover, this avoids the chain emissions of fossil kerosene, thus reducing emissions outside of aviation in addition. It is largely with this image and motivation of negative emissions and CO₂-neutral fuels in mind that some people and organisations are rapidly developing DAC technology.

⁴⁵ PKU Pioneer (2017): *PSA-CO Plant*

⁴⁶ PKU Pioneer (2015): *The Combustion Economy of Purifying CO from Blast Furnace Gas by Pressure Swing Adsorption*

⁴⁷ KTI (1988): *The Use of COSORB II to Recover High Purity Carbon Monoxide from a Feed Gas*. AICHE Summer Meeting.

⁴⁸ PKU Pioneer (2015): *The Combustion Economy of Purifying CO from Blast Furnace Gas by Pressure Swing Adsorption*

INITIATIVES AND ORGANISATIONS

Although research on DAC goes back a long time, including missions to outer space, the first companies aiming to build commercial DAC units and plants were formed in the 2000s. Carbon Engineering, formed in 2009, is probably the first DAC company. In 2016, they built the first 'large' demo plant, capable of capturing 0.5 kton of CO₂ from the atmosphere each year. The Swiss Climeworks is younger, but, building on research done at the ETH Zurich, managed to deliver the world's first commercial DAC plant with a capacity of 0.9 kton a year in 2017. Global Thermostat, an American company, has also built a demo plant. The Netherlands-based companies SkyTree and Antecy are still working on prototypes, but have also conducted significant research.

PROCESS

Due to its small concentration (400 ppm), air capture systems of scale will be restricted to working mechanisms with low energetic costs, such as absorption and adsorption. A typical DAC system is based on the principle of adsorption⁴⁹. Fans blow air through the contactors, where the sorbent binds CO₂ molecules. Chemically, this process happens spontaneously. Because of the low CO₂ concentration of air, however, fans (or some other mechanism) are needed to fill up the contactor area more quickly. When it is full (enough), heat is provided to release the CO₂ molecules in a very pure stream. Next, this stream is compressed to desired specification. All parties mentioned above use these principles, but their processes differ by design and sorbent choice. Climeworks, Global Thermostat, Skytree and Antecy all use solid sorbents, whereas Carbon Engineering uses a solution. Energy (and cost) reductions are to be expected from process design and scaling, as the carbon release can be performed for multiple DAC units simultaneously. We consider the technology readiness level to be 7, as Climeworks is already working at a small yet commercial scale.

CURRENT TECHNO-ECONOMICS

Currently, DAC is a relatively young and expensive technology. The Climeworks project cost 3 to 4 M€. Levelised capture costs are claimed to be \$600/t CO₂ (which includes the benefits of selling the CO₂ to a local vegetable grower)⁵⁰. The process

can be operated continuously. Current utility requirements are 500-650 kWh electricity/t CO₂ and 1500-2000 kWh heat/t CO₂ at about 105 °C for sorbent regeneration⁵¹. The Climeworks plant uses waste heat from a nearby waste incineration plant.

The basic plant could have a lifetime of 25 years, while the sorbent's lifetime is usually given in cycles (number of times CO₂ is released and the sorbent is regenerated), which typically amounts to 1 to 4 years. Due to the different gas mixture compared to flue gases (low concentration, yield less important), a different, more expensive sorbent is needed – with annualised costs of about €40/t CO₂⁵².

FUTURE TECHNO-ECONOMICS

An interview with Skytree confirmed that the process components used in a DAC plant are conventional and do not require rare materials. Currently, the integration of various components is performed manually, but every part can be standardised and industrialised. This is expected to bring down costs significantly. This is also reflected in the techno-economic expectations of DAC companies. The two DAC companies that seem most technologically advanced, Carbon Engineering and Climeworks, both believe capture costs of \$100/t CO₂ are feasible before 2030, including capital charge and at an output pressure of 150 bar (Carbon Engineering), which is more than sufficient for our purposes.

Climeworks expects long-term capital costs to result in a contribution to the CO₂ capture price of 30-50 \$/t, which makes about 1/3 of the expected total capture price of 100\$/t. We therefore estimate the CAPEX contribution to be 33\$/t, resulting from investment costs of about 50\$/(t CO₂/y) excl. capital charge. This is close to Carbon Engineering's projection: it foresees annualised capital costs of \$60/(t CO₂/y), but has lower operational costs⁵³. Electricity costs for Climeworks are 500-650 kWh/t CO₂ and heating costs 1600 kWh/t CO₂. The substantial remainder (to arrive at a total capture costs of 100\$/t CO₂) goes into the sorbent and other operational costs.

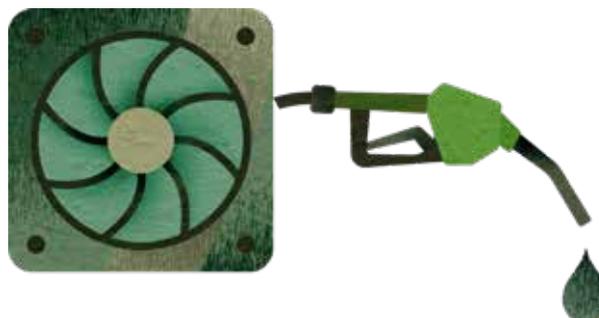
⁴⁹ K.S. Lackner et al. (2012): *The urgency of the development of CO₂ capture from ambient air*. PNAS.

⁵⁰ S. Evans (2017): *The Swiss company hoping to capture 1% of global CO₂ emissions by 2025*. CarbonBrief.

⁵¹ Climeworks (2017): *Capturing CO₂ from air*. DAC Workshop UKCCSRS.

⁵² APS (2011): *Direct Air Capture of CO₂ with Chemicals*

⁵³ Obtained from a presentation given by Carbon Engineering at the National Academy of Sciences Direct Air Capture Workshop on 24/10/2017, held in Irvine, CA, USA



IMPLEMENTATION

In our modelling, we consider a DAC plant with investment costs of \$50/ (t CO₂/y) and a lifetime of 25 years. Electricity requirements incl. compression are 550 kWh/t CO₂ and heating requirements 1600 kWh/t CO₂. Other operational costs are such that levelised capture costs are 100\$/t CO₂ (33 euro/t CO₂ in our base case). The process is expected to operate continuously.

CARBON CONVERSION

If carbon is captured as CO₂ and one wants to follow the Fisher Tropsch route, it is necessary to convert CO₂ to CO. This process is sometimes referred to as 'reverse combustion'. We have identified two main routes to do this, the reverse water gas shift (RWGS) and electrochemical reduction. Plasmolysis, plasma-driven disassociation of CO₂, is a currently lab-scale pathway that benefits from high energy efficiency and might prove a potent alternative in a more distant future⁵⁴.

REVERSE WATER GAS SHIFT (RWGS)

INTRO

The water gas shift reaction (WGS), an equilibrium reaction involving on the one hand CO and H₂O and on the other CO₂ and H₂, was discovered more than two centuries ago and partially enabled the industrial development and unprecedented growth. It is used as a means to produce hydrogen, and considered a quintessential part in ammonia production and steam methane reforming. Recently, the reverse reaction (RWGS) has attracted attention as a means to produce water on Mars⁵⁵, to control H₂ / CO ratios in chemical reactions and to synthesise fuels. It is the last application that has our interest.

INITIATIVES AND ORGANISATIONS

The first demonstration of the RWGS was the South-Korean CAMERE pilot plant, which converted CO₂ to CO for methanol production⁵⁶. More recently, Sunfire and Soletair have implemented the RWGS as part of their blue crude production chain. These are still demo plants; there is no large-scale RWGS plant yet, nor a company developing RWGS technology for commercialisation.

⁵⁴ W. Bongers et al. (2016): Plasma-driven disassociation of CO₂ for fuel synthesis. *Plasma Processes and Polymers*, 14 (6)

⁵⁵ NASA (2016): Demonstration of Robustness and Integrated Operation of a Series-Bosch System.

⁵⁶ O. Joo et al. (1999): Carbon Dioxide Hydrogenation to Form Methanol via a Reverse-Water-Gas-Shift Reaction (the CAMERE Process). *Ind. Eng. Chem. Res.*, 38 (5), 1808-1812

⁵⁷ I. Dimitriou et al. (2015): Carbon dioxide utilisation for production of transport fuels:

process and economic analysis. *Energy Environ. Sci.* 8, 1775-1789

⁵⁸ I. Dimitriou et al. (2015): Carbon dioxide utilisation for production of transport fuels: process and economic analysis. *Energy Environ. Sci.* 8, 1775-1789

PROCESS

The RWGS is an equilibrium reaction which reads:



Because this is an endothermic equilibrium reaction, it has to occur at elevated temperatures to drive production formation; typically, this means temperatures of at least 900 K⁵⁷. The reaction is rather sensitive to CO₂ / H₂ ratio; possible problems include solid carbon formation, which blocks the catalyst, and light hydrocarbon (e.g. methane) synthesis^{58 59}. Sunfire operates its RWGS reactor at 20-30 bar and at temperatures between 1100 - 1800 K⁶⁰. Higher temperatures and better catalysts improve CO₂ conversion, but the most effective measure is to remove the product (CO) to effectively make the equilibrium reaction unidirectional⁶¹. Product removal at these temperatures, however, is challenging, which means a multistage process could provide a (partial) solution. Doty et al. propose a three-stage process which seems promising⁶².

We consider the technology readiness level of this step to be 7, as the RWGS has been successfully implemented in several pilot plants. However, operational experience as well as theoretical analysis seem to indicate that scaling the RWGS might involve some hurdles.

CURRENT TECHNO-ECONOMICS

The techno-economics of the three-stage process of Doty et al. constitutes a mix of current and near future techno-economics. If we scale investment costs linearly with the CO flow rate, the basis is 3.6 M€/ (kg CO/s) for a RWGS plant with a 10-year lifetime in the 2020s⁶³. For yearly O&M costs that is 3% of CAPEX, the total fixed costs can be determined once the FLH are given. The energy requirements, relative to the flow rate, are about 1.8 MW / (kg CO/s) heating and 0.4 MW / (kg CO/s) compression. It is assumed that 0.95 of CO₂ is converted to CO.

FUTURE TECHNO-ECONOMICS

The CAPEX part of the current techno-economics is largely 'future techno-economics', as it does not describe current RWGS plants. There might be some scope for scaling reductions, but it first of all remains to be seen that the RWGS can be scaled to large-scale capacity without giving significant trouble.

⁵⁹ A.G. Kharaji (2013): Performance of Co-Mo/Al₂O₃ Nano Catalyst for CAMERE Process in a Batch Reactor. *Chem. Biochem. Eng. Q.*, 27 (3), 275-278

⁶⁰ Sunfire (2016): Synfuels from Electrolysis

⁶¹ F.D. Doty et al (2010): Toward Efficient Reduction of CO₂ to CO for Renewable Fuels. *ASME 2010 4th International Conference on Energy Sustainability*, 1, 775-784.

⁶² F.D. Doty et al (2010): Toward Efficient Reduction of CO₂ to CO for Renewable Fuels. *ASME 2010 4th International Conference on Energy Sustainability*, 1, 775-784.

⁶³ F.D. Doty et al (2010): Toward Efficient Reduction of CO₂ to CO for Renewable Fuels. *ASME 2010 4th International Conference on Energy Sustainability*, 1, 775-784.

IMPLEMENTATION

In our modelling, we consider the system described under 'current techno-economics'. FLHs are set to 8,000 hours, as this process is best run continuously given the multiple stages, equilibrium reaction and relatively high temperature requirements.

ELECTROCHEMICAL REDUCTION (PEM-CO₂)

INTRO

Water electrolysis is a form of electrochemistry. As it relies on electricity, it can easily be conducted on a lab scale but it is harder to design a large-scale process. Perhaps more importantly, it also used to be quite expensive, but this is changing. We see cheap electricity coming available in the form of wind and solar electricity, while at the same time electrolyzers are scaled to higher capacities and lower costs. This also opens up the opportunity to carry out other types of electrochemistry – at an increasingly larger scale and cheaper price. With 100% renewable electricity, this would then also immediately make the process renewable (utilitywise). Making hydrocarbons with electrolyzers is one of the options.

INITIATIVES AND ORGANISATIONS

Opus 12, a start-up from California, is pursuing precisely this. What is more, they also use a PEM electrolyser. By changing the catalyst at the cathode, they are able to produce different products of the type C_xH_yO_z instead of hydrogen, along with oxygen. So far, they are able to produce 16 different compounds, ranging from CO and methane to alcohols and building blocks for plastics⁶⁴. Catalytic Innovations seems to be on a similar track, but at a smaller scale and on a more exploratory basis with a preliminary focus on alcohols. Haldor Topsoe, a Danish company, already has a commercial unit, converting CO₂ into CO via solid oxide electrolysis.

PROCESS

The process is identical to that of a PEM water electrolyser, with the same reaction taking place at the anode, but a different one, depending on the catalyst at the cathode. For electrochemical reduction of CO₂ to CO, the catalyst is a metal nanoparticle catalyst. No other modifications to the PEM electrolyser are required.

The reaction that takes place is:



⁶⁴ Opus 12 (2016): *Opportunities & challenges in electrochemical CO₂ utilization using a PEM electrolyzer*

⁶⁵ Y. Zheng et al. (2017): *A review of high temperature co-electrolysis of H₂O and CO₂ to produce sustainable fuels using solid oxide electrolysis cells (SOECs): advanced materials and technology. Chemical Society Reviews, 5.*

Although the molar electricity requirements are similar for water and CO₂ electrolysis, the electricity requirement on a mass basis is much lower for CO₂ electrolysis. As a suppressed side reaction, conventional water electrolysis takes place. This does not pose a problem as this is in fact needed for the next step.

We consider the technology readiness level of this step to be 6, as Haldor Topsoe has a commercial SOEC unit and Opus 12 has developed some demo PEM units. It will however be 7 or 8 in Q1/2 2018, which is the planned release date for Opus 12's first commercial model. Given that it uses existing technology, it will probably be at full commercial readiness (9) shortly after, in 2019.

It should be noted that there is an interesting development focused on co-electrolysis. Co-electrolysis is the simultaneous electrolysis of H₂O to H₂ and CO₂ to CO, at high temperatures. Currently, studies are performed on a theoretical, simulation and early experimental level and TRL is very low⁶⁵. It may however prove an interesting step once it has been developed further.

CURRENT TECHNO-ECONOMICS

Generally speaking, the techno-economics and technical properties of a PEM water electrolyser serve as the ceiling or upper bound on that of a CO₂ electrolyser⁶⁶. While the system efficiency of a current PEM electrolyser is approximately 70%, that of Opus 12's current technology is 55%⁶⁷. CO is then delivered at a purity of up to 99.9% and an elevated pressure of up to 35 bar, which is more than sufficient for our subsequent conversion processes. The relatively low purity does not pose a problem, because the other compound is hydrogen, which is needed for further upgrading anyway. Investment costs of regular PEM technology (at the MW scale) were estimated to be €800/kW, and catalyst modification does not add any significant cost. In terms of lifetime of operation, what has been said of PEM water electrolyzers also holds true of PEM CO₂ electrolyzers.

Opus 12 has also conducted experiments on feed gas composition. They found that if the CO₂ content in feed gas is greater than 50%, the CO₂ electrolyser also operates successfully. This works if other compounds in the feed gas are H₂, CO and inert gases such as N₂.

⁶⁶ This paragraph is based on a discussion with Nicholas Flanders, CEO of Opus 12.

⁶⁷ Opus 12 (2016): *Opportunities & challenges in electrochemical CO₂ utilization using a PEM electrolyzer*

FUTURE TECHNO-ECONOMICS

Financially, we expect the CO₂ electrolyser to have the same parameters as the water electrolyser. Concerning efficiency, Opus 12 thinks the long-term target is 75% (the current best water electrolyser efficiency). However, as regular PEM technology improves and the upper bound increases, CO₂ electrolysis also has a large scope for improvement. Because it is a drop-in solution, it will probably lag behind a little.

IMPLEMENTATION

In our modelling, we consider an 75% efficient PEM CO₂ electrolyser with investment costs of €300/kW. We assume the stack accounts for 15% of total investment costs and is replaced every 10 years, while the rest of the system has a lifetime of 30 years. O&M costs are 3% of CAPEX. Because of selectivity and conversion yield, the system delivers 95% CO, 2% CO₂ and 3% H₂ when fed 99.99% pure CO₂. Full-load hours (FLHs) are identical to those of the renewable electricity production plants which provide the electricity required.

KEROSENE SYNTHESIS

Having obtained CO₂ and/or CO as well as H₂ from the previous steps, we have the building blocks to synthesise kerosene. Below we discuss two different routes to do so.

SYNGAS ROUTE (FISCHER-TROPSCH)

INTRO

In the early 20th century, Germany rapidly became the world's leading car manufacturing country. Whereas car production was sky rocketing, oil production was not; the country had very small petroleum reserves and imported it, but was very rich in coal. It set out to develop a process to produce fuels from its coal, and in the 1920s, two scientists succeeded. From syngas produced from coal, they were able to produce liquid fuel via their Fischer-Tropsch (FT) process. Over decades the process was improved, and it is used in several large-scale gas-to-liquids (GTL) and coal-to-liquids (CTL) plants around the world, such as Sasol's in South Africa and Shell's in Qatar. The feedstock of this process is syngas, making it possible to produce liquid fuels from coal, natural gas or biomass – instead of crude oil in a conventional refinery.

⁶⁸ Oxford Energy Institute (2013): *Gas to Liquids. Historical Developments and Future Prospects.*

⁶⁹ Shell (2016): *Shell starts new aromatics unit at Pernis refinery in the Netherlands*

⁷⁰ H-J Lee (2010): *Optimization of Fischer-Tropsch Plant*

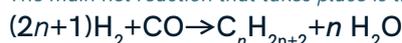
⁷¹ Q. Zhang et al. (2014): *Fischer-Tropsch Catalysts for the Production of Hydrocarbon Fuels with High Selectivity. ChemSusChem, 7, 1251-1264.*

INITIATIVES AND ORGANISATIONS

FT synthesis is widely employed around the world, at a very large scale. Shell owns the Pearl plant in Qatar, which has a capacity of 140k US barrels (bbl) a day; Sasol in South Africa operates several plants, with the largest producing 124k-154k barrels a day. For comparison, Shell's Pernis crude oil refinery, the largest in Europe, produces 404k barrels a day. FT synthesis is clearly already carried out at a very large scale and has had many decades to be 'perfected'.

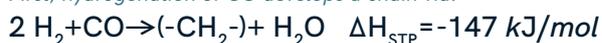
PROCESS

The main net reaction that takes place is the following:



where alkane fractions in the range $n \in [8, 15]$ make up the kerosene range. In practice, various co-reactions occur. The process consists of many steps, of which we highlight the key ones (which often themselves are composed of steps).

First, hydrogenation of CO develops a chain via:



This is a stochastic process which is typically modelled as a probabilistic chain growth, following the ASF distribution⁷⁰. Operating conditions and the catalyst determine how likely it is a chain keeps growing. The product is a mixture of hydrocarbons of various lengths, from light gases to waxes⁷². This process is highly exothermic and is operated at pressures of 20-30 bar with a metallic e.g. cobalt catalyst⁷³. The heat released can be used to regenerate sorbents in the carbon capture step.

Next, the mixture can be upgraded via conventional refinery processes such as hydrocracking and distillation⁷⁴. For our purposes, we want to design a large-scale process with high selectivity to kerosene in an economic way. On a small scale, a selectivity of over 90% to jet fuel has been achieved. It is possible to, on a large-scale, produce 55% kerosene fractions, 35% heavier (diesel) fractions and 10% light gases, which are recycled. This fraction is to some extent configurable; theoretically one could manipulate hydrocarbons until a desired fraction has been obtained, but in practice this is undesirable from a financial and/or kinetic point of view. We consider the technology readiness level of FT synthesis and upgrading to be 9.

⁷² Imperial College (2014): *Establishing a European renewable jet fuel supply chain: the techno-economic potential of biomass conversion technologies.*

⁷³ Sunfire (2016): *Synfuels from Electrolysis*

⁷⁴ Imperial College (2014): *Establishing a European renewable jet fuel supply chain: the techno-economic potential of biomass conversion technologies.*

CURRENT TECHNO-ECONOMICS

The National Energy Technology Laboratory (NETL) of the US Department of Energy has done research on many technologies, including GTL. Since this includes conversion of natural gas to syngas, we need only consider that part of the technology downstream of syngas. Investment costs are about 34.4k\$/bpd, which includes 10.3k\$/bpd for product upgrading⁷⁵. These costs are higher than the estimated costs of the Oryx plant of roughly 23k\$/bpd (excluding syngas production), but GTL plants have a reputation for escalating costs⁷⁶.

Yearly O&M costs are assumed to be 5% of CAPEX. Power requirements (excluding syngas production) are 65.4 MW for a plant with a 50k bpd production capacity. The capacity⁷⁷ of the PtL train described in the next chapter is greater, but not much, so we scale power requirements linearly. It is assumed plant lifetime is 30 years.

FUTURE TECHNO-ECONOMICS

Given the age and scale of the FT process, we do not expect many significant technical improvement or cost reductions to be achieved.

IMPLEMENTATION

In our modelling, we consider the system described in the current techno-economics section. It is assumed the process, after recycling of light gases, produces 61% kerosene and 39% diesel. The process is expected to operate continuously and at virtually constant capacity; capacity can be shifted by 10% in 12 to 24 hours when operational, but not by more.



⁷⁵ NETL (2013): *Analysis of Natural Gas-to Liquid Transportation Fuels via Fischer-Tropsch*

⁷⁶ Oxford Energy Institute (2013): *Gas to Liquids. Historical Developments and Future Prospects.*

⁷⁷ NETL (2013): *Analysis of Natural Gas-to Liquid Transportation Fuels via Fischer-Tropsch*

⁷⁸ MIT Technology Review (2006): *The Methanol Economy.*

⁷⁹ Stena Oil (2016): *Methanol: The marine fuel of the future. Updates from the Stena Germanica*

ALCOHOL ROUTE (METHANOL/ETHANOL)

INTRO

The idea of a hydrogen-economy emerged in the 1970s and has recently enjoyed a new wave of interest (see also electrolyzer section). Less well-known is the idea of a methanol economy, proposed by Nobel prize winner George Olah. Olah argues methanol is a better fuel and easier to transport, store and use than hydrogen⁷⁸. In fact, methanol is already used as a fuel nowadays. It can be blended with gasoline and used in Internal Combustion Engines (ICEs), but is also a potential low-sulphur shipping fuel – something the Stena Germanica, the world's first methanol powered ferry, has demonstrated⁷⁹. As a chemical, methanol can be an important building block for plastics, but even be upgraded to conventional fuels – which is what we focus on.

INITIATIVES AND ORGANISATIONS

The general family of these conversion and upgrade processes is known as Alcohol-to-Jet (AtJ); the processes are largely the same, but they typically differ in alcohol. We focus on processes which include methanol and ethanol as an intermediate, and we start with the former.

Carbon Recycling International (CRI) from Iceland has built the world's largest power to methanol plant, capable of producing 4 kt methanol a year. CRI uses CO₂ and H₂ as building blocks for this⁸⁰. In terms of upgrading, the most notable existing process is Mobil's methanol-to-gasoline (MtG) process; several large MtG plants (up to 25k bpd) have been constructed and operated since the 1980s⁸¹. Although the product of this process is gasoline and not kerosene, it shares many steps with a theoretical methanol-to-kerosine (MtK) process. The latter pathway remains to be demonstrated and scaled, as we have not found any record of a MtK facility yet⁸². The US company Primus Green Energy does claim to be able to produce kerosene from methanol, via its syngas-to-gasoline+(StG+) technology⁸³.

⁸⁰ CRI (2017): *CO 2 to Renewable Methanol: experiences and perspectives for the steel industry*

⁸¹ ExxonMobil (2014): *Methanol to Gasoline Technology. An Alternative for Liquid Fuel Production*

⁸² Umwelt Bundesamt (2016): *Power-to- Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

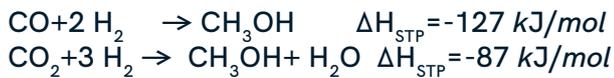
⁸³ Primus Green Energy (2014): *DOE QER Primus' STG+ Flared Gas Solutions*

Kerosene production from ethanol is more advanced. The New Zealand / US company LanzaTech uses a microbial approach of gas fermentation; microbes grow on industrial waste gases (CO, CO₂, H₂) and release ethanol and other chemicals⁸⁴. By 2016, LanzaTech had produced 4,000 gallons of jet fuel, upgraded chemically from this ethanol, which meets ASTM specifications but whose approval is pending⁸⁵. No kerosene from methanol has been produced yet, so approval seems further away for this route. One ATJ route has been certified so far: the American company GEVO in 2016 received approval for blends up to 30% of ATJ fuel made from isobutanol⁸⁶.

PROCESS

Methanol can be produced in various ways, such as from CO₂, CO and CH₄ (methane). We concentrate on two routes which involve CO and CO₂.

Through hydrogenation, one obtains methanol via⁸⁷:



Both reactions are quite strongly exothermic. It should be noted that the RWGS occurs in parallel



Methanol production occurs at elevated pressure and temperature. CO₂ and H₂ enter at a pressure of 20 bar and are compressed to almost 80 bar; they then react at temperatures of roughly 500 K⁸⁸. The selectivity to methanol is 0.998, other products include other alcohols⁸⁹.

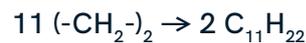
Once methanol has been produced, it is upgraded to kerosene via di-methyl-ether (DME) synthesis, olefin synthesis, oligomerization and hydrotreating; these are all conventional processes that are carried out at a large scale in refineries and other chemical plants; DME synthesis occurs as follows⁹⁰



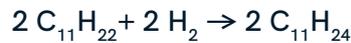
One could also synthesise DME directly and skip methanol as an intermediate. Then one synthesises olefins (the process up to here is sometimes referred to as the methanol-to-olefins (MtO) process⁹¹) via⁹²:



Through catalytic oligomerization, one obtains olefins (i.e. alkenes) in the range C₄ to C₃₂ (sensitive to operating conditions and catalysts)⁹³. We represent this reaction as resulting in an average hydrocarbon length of 11



Lastly, though hydrogenation, we obtain alkanes or paraffins, specifically synthetic paraffinic kerosene (SPK) fractions



The resulting mixture should adhere to ASTM specifications, but approval should be obtained.

The carbon efficiency of this process is unclear. We can use the carbon efficiency of the study of Baliban et al. as an indication, after compensation for their gasification stage: this results in a carbon efficiency of about 60-70%⁹⁴. We consider the technology readiness level of methanol synthesis and the individual processes to be 9, but the methanol-to-kerosene upgrade to be 1 or 2, as it has not been demonstrated.

⁸⁴ LanzaTech (2014): *Circular Economy through C1 fermentation*

⁸⁵ LanzaTech (2017): *Flying a Carbon Smart Future!*

⁸⁶ Green Air Online (2016): *Standards body ASTM approves Gevo's alcohol-to-jet renewable jet fuel for commercial aviation use*

⁸⁷ E. Simões Van-Dal and C. Bouallou (2013): *Design and simulation of a methanol production plant from CO₂ hydrogenation. Journal of Cleaner Production, 57, 38-45.*

⁸⁸ E. Simões Van-Dal and C. Bouallou (2013): *Design and simulation of a methanol production plant from CO₂ hydrogenation. Journal of Cleaner Production, 57, 38-45.*

⁸⁹ B. Anicic et al. (2014): *Comparison between two methods of methanol production from carbon dioxide. Energy 77, 279-289*

⁹⁰ Umwelt Bundesamt (2016): *Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

⁹¹ R.C. Baliban et al. (2013): *Thermochemical Conversion of Duckweed Biomass to Gasoline, Diesel and Jet Fuel: Process Synthesis and Global Optimization. Industrial & Engineering Chemistry Research, 52 (33), 11436-11450*

⁹² Umwelt Bundesamt (2016): *Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

⁹³ J. Han et al. (2017): *Well-to-wake analysis of ethanol-to-jet and sugar-to-jet pathways. Biotechnology for Biofuels.*

⁹⁴ R.C. Baliban et al. (2013): *Thermochemical Conversion of Duckweed Biomass to Gasoline, Diesel and Jet Fuel: Process Synthesis and Global Optimization. Industrial & Engineering Chemistry Research, 52 (33), 11436-11450*

ETHANOL

For the ethanol route, alcohol synthesis is quite different but upgrading rather similar. LanzaTech uses patented techniques and works with microbes that use both energy and carbon from a steel plant's waste gases. This waste gas fermentation results in ethanol, 2,3 butanediol and other compounds. For LanzaTech, in Q2 2018, commercial facilities are expected to open, producing a total of 130 kton or 42.7 M gallons of ethanol each year⁹⁵. Upon dehydration ethanol becomes ethylene, which then follows the above steps of oligomerisation, hydrogenation and fractionation⁹⁶. This quantity of ethanol can be converted to 21.4 M gallons or 60.5 kton of kerosene⁹⁷. This means the selectivity, on a molar basis, is roughly 77%, if we assume an average C-number of kerosene of 11. This corresponds well with the selectivity Lanzatech suggests⁹⁸.

CURRENT TECHNO-ECONOMICS

We consider the techno-economics of the methanol synthesis and upgrade steps separately. To start with the former, investment costs are considered 183 M\$ for a plant producing 5 kton methanol a day for 25 years⁹⁹¹⁰⁰. Yearly O&M costs is assumed to be 3% of CAPEX. The process is exothermic and has no auxiliary heat requirements; electricity requirements are 1.2 GJ/t methanol¹⁰¹ or 332 kWh/t methanol. The carbon efficiency is an estimated 0.6-0.7, of which we will use the average.

For the techno-economics of the methanol upgrade we consider that of the MtG process in comparison with other MtX upgrading processes. For a 16.667 k bbl/d gasoline MtG facility, investment costs are 154.7 M€, or 9.3 M€ per k bbl/d capacity¹⁰². Lifetime is expected to be 20 years, and yearly O&M costs 5% of CAPEX. For a 50k bbl/d MtG facility, electrical power of 112 MW is needed for operation, which comes done to about 450 kWh/t product¹⁰³.

For a MTO upgrade to diesel and kerosene fractions (besides gasoline) at a 5 k bbl/d scale, investment costs are 37 M\$, or 7.4 M\$ per k bbl/d capacity¹⁰⁴; this excludes hydrocarbon production, but is relatively close to the 'pure' MtG process. For a conservative estimate we add 20% to the MtG investment price of 9.3 M€ per k bbl/d capacity, arriving at 11.2 M€ per k bbl/d capacity for a methanol to kerosene plant.

⁹⁵ LanzaTech (2017): *Recycling Carbon for Sustainable Aviation Fuel*

⁹⁶ DOE (2017): *A Hybrid Catalytic Route to Fuels from Biomass Syngas*

⁹⁷ World steel association (2017): *A low-carbon jet fuel future?*

⁹⁸ LanzaTech (2017): *WTE Workshop*

⁹⁹ B. Anicic et al. (2014): *Comparison between two methods of methanol production from carbon dioxide*. *Energy* 77, 279-289

¹⁰⁰ Innovatum (2017): *Liquid Wind*

¹⁰¹ E. Simões Van-Dal and C. Bouallou (2013): *Design and simulation of a methanol production plant from CO₂ hydrogenation*. *Journal of Cleaner Production*, 57, 38-45.

¹⁰² VTT (2013): *Liquid transportation fuels via large-scale fluidised-bed gasification of lignocellulosic biomass*

For the ethanol pathway that LanzaTech pursues, we could find little information. We know the selectivity is higher and the process has been developed further, but we know little about the economics as well as the energy requirements of the ethanol synthesis step. Costs for upgrading should be similar as for the methanol pathway, but probably slightly smaller as the starting molecule is larger and closer to the desired product.

FUTURE TECHNO-ECONOMICS

The estimates above already concern the future techno-economics.

IMPLEMENTATION

In our modelling, we consider the alcohol to jet pathway via methanol, as described in the current techno-economics section. The reason for this is that we cannot accurately model ethanol synthesis at this stage. The process is expected to operate continuously and at virtually constant capacity.

KEROSENE UTILISATION

The first commercial flight which ran on a 50/50 blend of synthetic GTL and fossil kerosene departed in 2009¹⁰⁵. Many planes have flown on such blends since. The ASTM, the standardisation body which also certifies fuels, details the requirements a synthetic fuel should meet in its ASTM D1655 and ASTM D7566 (-17a) standard¹⁰⁶. So far, several production pathways have been approved, but always in blends with a synthetic fuel content of no more than 50%. As synthetic fuels contain very few aromates, which also serve as lubricants to the engine, synthetic fuel usage is restricted to blends. Planes have flown with CTL FT kerosene in blends (up to 50%) with fossil kerosene without any major problems since 1999¹⁰⁷. Using such blends thus seems safe and reliable. Short term tests on 100% synthetic kerosene have been successful, but long-term effects on the engine are unknown.

¹⁰³ G. Liu & E.D. Larson (2014): *Gasoline from Coal via DME with Electricity Co-Production and CO₂ Capture*. *Energy Procedia*, 63, 7367-7378

¹⁰⁴ R.C. Baliban et al. (2013): *Thermochemical Conversion of Duckweed Biomass to Gasoline, Diesel and Jet Fuel: Process Synthesis and Global Optimization*. *Industrial & Engineering Chemistry Research*, 52 (33), 11436-11450

¹⁰⁵ Flight Global (2009): *Qatar Airways makes world's first gas-to-liquid-fuelled revenue flight*

¹⁰⁶ ASTM (2017): *Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons*

¹⁰⁷ Imperial College (2014): *Establishing a European renewable jet fuel supply chain: the techno-economic potential of biomass conversion technologies*.

ALTERNATIVE ROUTES

Besides the routes mentioned at the start of the Process chapter, which consist of combinations of process steps explained above, there are also pathways which perform steps in a different order. We briefly cover some of these for completeness.

SORPTION ENHANCED WATER GAS SHIFT (SEWGS)

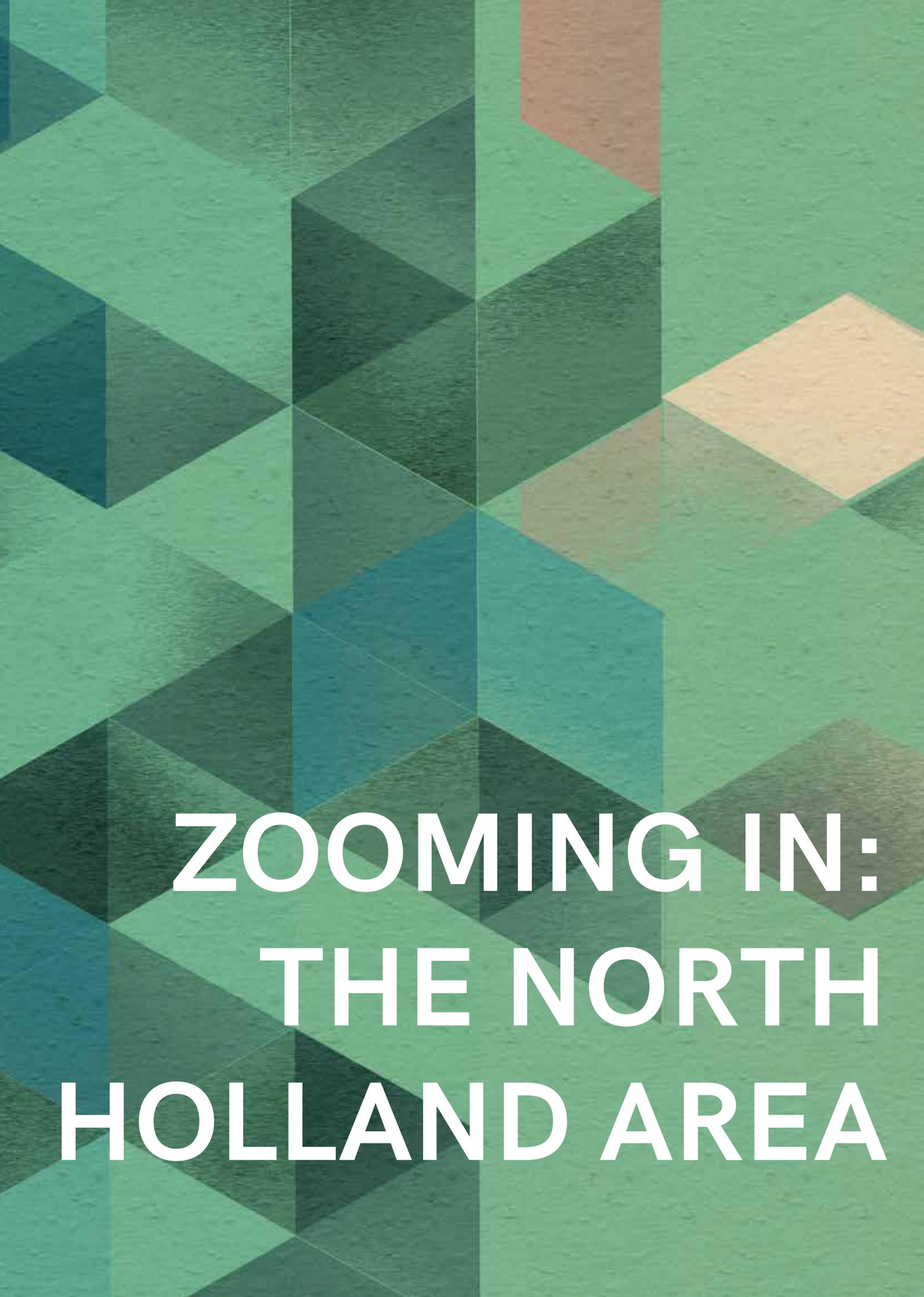
An alternative route would be the Sorption Enhanced Water Gas Shift (SEWGS) route¹⁰⁸. In this route, one first uses the WGS in the steelplant's waste gases in the forward direction, resulting in CO_2 and H_2 formation. This reaction is driven by CO_2 capture, leaving H_2 and N_2 . Upon separation of the latter two (e.g. through a membrane), we have CO_2 and H_2 separately. Now we can use the RWGS reaction to convert this into CO and H_2O . This CO can then be combined with H_2 to form syngas or to produce methanol or ethanol. The advantage of this route is that it avoids CO capture, which is more difficult than CO_2 capture. However, it also calls for an additional step, which is the WGS (combined with CO_2 capture which is also used in the regular pathway). Based on our data and modelling, this is economically disadvantageous.

DIRECT FROM TATA TO OPUS 12 OR METHANOL SYNTHESIS

From discussions with Tata Steel and Opus 12 an idea for a different route emerged. In the normal route, CO_2 , followed by CO , would be captured from Tata Steel, converted to CO if necessary, and then synthesised and upgraded to kerosene. Alternatively, one could directly feed in Tata's waste gases into Opus 12's PEM CO_2 electrolyser or into the methanol synthesis unit. For the CO_2 electrolyser, the molar CO_2 fraction in the gas mixture should be at least 50%. This may require CO_2 enrichment of the waste gases, for instance through DAC. For methanol, the minimum is unknown. One would still have to separate the resulting CO or methanol from the N_2 that remained in the mixture. CO_2 capture is no longer necessary, but all carbon is now captured as CO . The other process steps are the same, but their order and flow size are different. Since flows will be larger and CO capture is more difficult and expensive than CO_2 capture, we work with the process outlined originally.

¹⁰⁸ D. Jansen et al. (2013): SEWGS is now ready for scale-up! *Energy Procedia* 37, 2265-2273





**ZOOMING IN:
THE NORTH
HOLLAND AREA**



The North Holland area in the Netherlands seems like an excellent location for a PtL kerosene production facility. It has access to sources of water, carbon and electricity, and there is already an extensive infrastructure for electricity and kerosene transport in place - as well as a very large consumer. In the next subsections, we will cover these six factors in more detail.

POINT SOURCE OF CARBON - TATA STEEL

Tata Steel's steelmaking process in IJmuiden is one of the largest emitters of CO₂ in the Netherlands. It could thus provide a sizeable amount of carbon. Carbon capture from steel plants' waste gases has also been demonstrated.

CURRENT PROJECTS AND PLANTS

Initiatives to reduce CO₂-emissions in steelworks are carried out in the ULCOS programme in Europe and in COURSE50 in Japan. The STEPWISE project aims to, on a 14t CO₂/d pilot scale, convert CO to CO₂ via SEWGS and capture CO₂ in blast furnace gases¹⁰⁹⁻¹¹⁰. FReSMe takes things one step further and intends to produce methanol from the CO₂ captured from the blast furnace gas at a steel plant in Sweden¹¹¹. Even large-scale carbon capture at steel plants is successful. Emirates Steel has the first operational CCUS plant (using the MEA sorbent) in a steel-making facility with a 0.8 Mton/y capacity at >98% purity¹¹².

TATA STEEL'S PLANT

Most steel production worldwide uses the blast furnace - basic oxygen furnace (BF-BOF) route, as does Tata Steel in IJmuiden. In this route, cokes are produced by pyrolysis of coal in the coke oven (CO), releasing coke oven gases (COG). In the air blown BF, prepared iron ore, sinter and cokes enter at the top of the furnace and the oxygen in the hot air blow reacts with the coke to form reductants which reduce the iron ore, producing liquid iron due to the high temperature¹¹³. Blast furnace gases (BFG) are released in this process; the molten iron is transferred to the basic oxygen furnace, where impurities are removed through oxidation with pure oxygen and steel is made to desired specification and waste gases, referred to as basic oxygen furnaces gases (BOFG), are released. This is depicted in Figure 3.

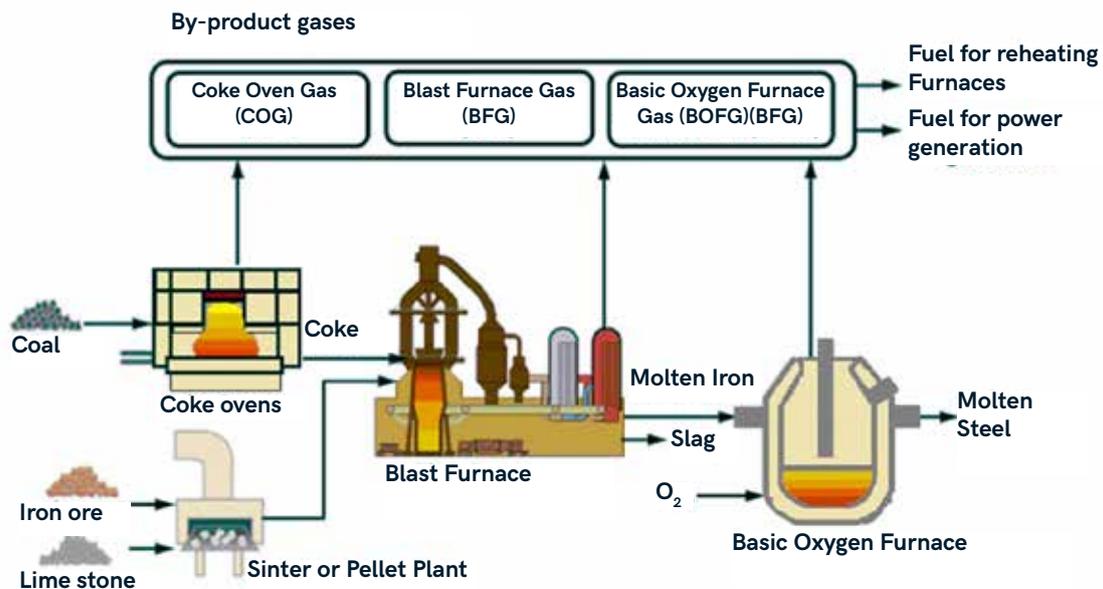


Figure 3: Steelworks blast furnace - basic oxygen furnace route ¹¹⁴

¹⁰⁹ ECN (2017): STEPWISE: cost effective capturing of CO₂ in the Iron & Steel industry

¹¹⁰ Global CCS Institute (2015): STEPWISE Pilot of SEWGS Technology at Swerea/Mefos

¹¹¹ ECN (2017): FReSMe - From Residual Steel Gases to Methanol

¹¹² Masdar Institute (2015): Perspective from Emirates Steel Project/ UAE. CCS Pathways to Commercialisation

¹¹³ IEA (2012): CO₂ abatement in the iron and steel industry.

¹¹⁴ W. Uribe-Soto et al. (2017): A review of thermochemical processes and technologies to use steelworks off-gases. Renewable and Sustainable Energy Reviews 74, 809-823

¹¹⁵ Tata Steel (2016). Sustainability Report 2015-2016.

Tata Steel's IJmuiden steelmaking facility emits roughly 12 Mton concentrated CO₂-eq/y. Roughly half of this is emitted directly, the other half is emitted by the nearby NUON power plants which combusts Tata's waste gases¹¹⁵. One of these plants, the IJmond 1 CHP, runs on BFG and BOFG exclusively, whereas the Velsen Noord plant (consisting of a base and backup unit) runs on natural gas in addition, but mainly on steel off gases^{116 117}. The latter's natural gas consumption contributes to its CO₂ emissions, but we consider these to be negligible.

CARBON AVAILABILITY

We will now look into the gas flows and capture potential in more detail. The largest gas flow emerges from the BF, about twenty times that of the others in volume and containing 20.5 mol% CO₂, 23.9 mol% CO and 1.1 mol% CH₄ and no other carbon-containing compounds¹¹⁸. This amounts to roughly 70% of the carbon input of the plant¹¹⁹. This is the waste gas that most capture efforts in the steel industry have focused on, as it is large and (relatively) free of contaminants. With capture of 99.9% of CO₂ and 98% of CO (see Process chapter), one thus obtains about 2.7 Mton CO and 4 Mton CO₂ from the BFG¹²⁰. The BOFG, much smaller in volume but richer in CO, can also be captured. This would give another 0.4 Mton CO and 0.2 Mton CO₂, giving a total capture potential of 3.1 Mton CO and 4.2 Mton CO₂ from Tata Steel's flue gases. The COG stream cannot be captured, as it is used by Tata and contains several compounds which make capture difficult.

The location of the carbon capture facility within the process is critical, as post-combustion capture will alter gas flows, which would require adjustments to the power plants and other downstream units¹²¹. Currently, the BFG and BOFG are partially combusted on-site and partially sold to NUON, which uses them to generate electricity – some of which goes to TATA. Carbon capture would mean that NUON no longer receives its main fuel for its plants. Given their age, the plans of the government to reduce CO₂ emissions (especially at power plants) and the increase of wind and solar production, it is more likely they will be closed than (retrofitted to) run on other fuels. This has some financial consequences as well, since Tata would no longer receive any financial compensation or electricity for the gases it supplied, which we will discuss in the chapter on business cases.

¹¹⁶ *Ecofys (2016): Feasibility check on correction factor and benchmark updates in EU ETS phase IV.*

¹¹⁷ *DHV (2008): DHV Power Stations.*

¹¹⁸ *W. Uribe-Soto et al. (2017): A review of thermochemical processes and technologies to use steelworks off-gases. Renewable and Sustainable Energy Reviews 74, 809-823*

¹¹⁹ *TNO and Universiteit Utrecht (2009): The impacts of CO₂ capture technologies in power generation and industry on greenhouse gases emissions and air pollutants in the Netherlands.*

WASTE GAS OPTIONS

Tata Steel can in fact choose to do various things with its waste gases, and is currently evaluating its options. It recently co-commissioned the CORESYM (CarbOn-monoxide RE-use through industrial SYMbiosis) project, which investigated opportunities for CO up-cycling from the steel industry's waste gases¹²² (CO₂ upcycling is not considered). Besides producing kerosene and other transport fuels from these gases, Tata could potentially produce base chemicals and hydrogen. Alternatively, it could decide to store the CO₂ it emits (after burning the CO in the NUON power plants). If Tata decides to use its flue gases for other purposes than kerosene synthesis, kerosene could still be produced from other sources including the ambient air, although that would perhaps delay commercialisation of potential Dutch synthetic kerosene production.

SOURCE OF H₂O – NORTH SEA / 'T IJ

Producing synthetic kerosene requires large quantities of hydrogen. If this is produced by means of electrolysis, a large source of water is needed. Fortunately, North Holland is conveniently positioned with respect to two large bodies of water: 't IJ and the North Sea. Since water contains minerals and sea water also contains salts, these will have to be removed prior to the production process. ITM's electrolyser already incorporates a purification step, which demineralizes the water. There seems to be little constraint on the kerosene production capacity of a synthetic kerosene plant in this area from a water perspective – especially since this process constitutes not only a carbon, but also a water cycle.

¹²⁰ *Detailed calculations can be found in the synthetic kerosene production model, which will be shared with all participants of this project.*

¹²¹ *Element Energy, Imperial College et al. (2014): Demonstrating CO₂ capture in the UK cement, chemicals, iron and steel and oil refining sectors by 2025: a techno-economic study.*

¹²² *Metabolic (2017): CORESYM*

ELECTRICITY PRODUCTION – (DRIVEN BY) DUTCH GOVERNMENT

The Dutch government plans to increase installed offshore wind turbine capacity by 1 GW a year as from 2023, and discussions are held to increase this to 2 GW a year. According to current plans, which we consider a baseline, roughly 10 GW of offshore wind capacity will be present on the North Sea close to the North Holland area (see Figure 4).

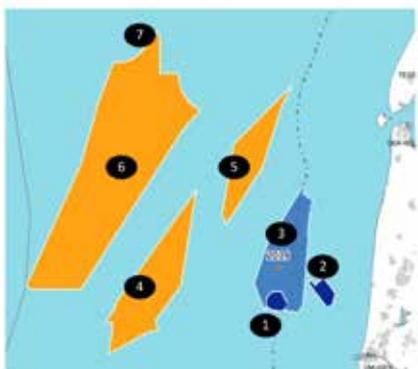


Figure 4: Current and future offshore wind farms off the IJmuiden coast, operational by 2030 (latest)

1. Prinses Amaliapark (120 MW)
2. OWEZ (108 MW)
-in operation
3. Hollandse Kust Noord (700 MW)
-operational in 2023 (exp.)
-connected in Beverwijk or Vijfhuizen
4. 'Gebied C' (1,500 MW)
5. Gebied D' (unknown MW)
6. IJmuiden Ver (6,000 MW)
-operational in 2030 (exp.)
7. Extension north of IJmuiden Ver of 2000 MW

Total: >10,000 MW

If ambitions increase, as well as on a further horizon and if we consider the full off-shore potential near the Netherlands, we may expect there to be tens of GW installed capacity. This is a very sizeable production of electricity and would suffice to produce significant quantities of synthetic kerosene. Of course, it should be noted that one cannot simply assume this electricity is to be utilised solely for renewable kerosene production; there will be many other consumers of electricity. This we will address in the next chapter.

ELECTRICITY TRANSPORT – TENNET

TenneT, the transmission system operator, operates the high voltage grid in the Netherlands. As such, it is also charged with the transmission of offshore wind electricity onshore. IJmuiden will be one location where a significant fraction of this electricity will land. If a capacity of tens of GW is installed, quantities of electricity will be so large they most probably cannot be consumed in direct or close vicinity. TenneT would

then either have to convert (the remainder of) this electricity to H₂ or transport it further inland. Both options require significant investments; HV grid expansion costs are estimated to be 5 M€ / 2.5 GW wind capacity / km grid expansion. In the case of H₂ production, hydrogen will have to be transported further as well. If there will be a Mt scale synthetic kerosene plant, this would avoid significant investments and transport costs, which are only required at peak production. In addition, it would give TenneT more flexibility and time to plan and construct its infrastructure. Lastly, such infrastructure would require a lot of space in an already dense area and is likely to meet opposition from locals for aesthetic reasons. From an electricity transmission perspective, a synthetic kerosene plant in the North Holland area would therefore be highly beneficial.

KEROSENE STORAGE AND TRANSPORT – OILTANKING, KOOLE TERMINALS, PORT OF AMSTERDAM

Another reason North Holland seems like an excellent location are the large storage facilities and existing transport infrastructure in the Port of Amsterdam. Oiltanking Amsterdam stores large amounts of fuels in its terminals: almost 1.6 billion cubic meters¹²³. Koole Terminals has a smaller storage capacity of about 0.17 million cubic meters and focuses on bio-based fuels and vegetable oils and fats¹²⁴. Although it might take longer for fossil fuel demands to decrease, diesel and gasoline demand are expected to drop due to electrification of transport¹²⁵. As a result, diesel and gasoline storage at the Port of Amsterdam will also decrease. Synthetic kerosene and bulk chemicals could take their place, as well as that of fossil kerosene. The direct pipeline to Schiphol airport (and Rotterdam) as well as Port of Amsterdam's international connections also ensure that transport to a large network of end-users is already possible.

KEROSENE CONSUMPTION – SCHIPHOL (KLM)

Schiphol Airport is the Netherlands' largest as well one of the world's largest airports in terms of (passenger) traffic. In 2016, 163.3 PJ of jet fuel was bunkered in the Netherlands¹²⁶. Schiphol Airport accounted for roughly 89.5% of all flight traffic (incl. passenger, goods and post but excluding military flights) from the Netherlands in 2016¹²⁷. Since virtually all long-haul and freight flights leaving from the Netherlands depart from Schiphol, we will compensate and assume it is responsible for 95% of the kerosene bunkering demand of the Netherlands. This is equivalent to 155 PJ or 3.6 Mton kerosene, which when combusted results in over 11 Mton CO₂. Another source states Schiphol receives roughly 10 kton kerosene a day¹²⁸, which amounts to 3.65 Mton kerosene a year if this number is the true daily average. With such kerosene demand, which we also expect to grow, there is little concern for the uptake of synthetic kerosene when economically (or otherwise) competitive. Currently, synthetic can be blended for up to 50% for FT kerosene and 30% for AtJ kerosene (from isobutanol), but more pathways are up for approval or extension¹²⁹.

SCENARIOS AND BUSINESS CASES

We have modelled the process (described in the Process chapter) in a synthetic kerosene production model, which is available as a separate electronic appendix. We will first define the system boundaries and assumptions, before defining the scenarios we will consider. Scenario definition is done in terms of several parameters which have a large impact on the business case, but are also very uncertain. For each scenario, we will explicitly consider the synthetic kerosene break-even price and CO₂ abatement costs.

SYSTEM DEFINITIONS AND ASSUMPTIONS

Our system is composed of all process steps described in the Process chapter: the starting point is flue gases and/or ambient air, as well as water, the final product is kerosene. The kerosene plant is located in the IJmuiden area or the greater Amsterdam area and has 2030 as a reference year. Electricity generation and kerosene transport are outside the system boundaries; it is assumed renewable electricity is bought. In this section, we specify electricity generation, describe how the process is integrated and operated and lastly provide financial definitions and assumptions.

ELECTRICITY GENERATION

We saw earlier that the Dutch government already has plans to install about 10 GW of wind capacity offshore the coast of IJmuiden; if it is decided that the yearly added capacity from 2023 onwards is raised from 1 to 2 GW, there will be a larger capacity in this area in 2030. We will use an intermediate estimate and assume there will be 15 GW offshore wind installed, and 2 GW solar nearby IJmuiden in 2030. Furthermore, we assume the electricity market obeys the same rules and mechanisms as it does now.

¹²³ Oiltanking (2017): *Services*

¹²⁴ Koole Terminals (2017): *Amsterdam, Zaandam.*

¹²⁵ Quintel (2017): *The Future of Energy-Intensive Industries in the Netherlands: The Story.*

PROCESS OPERATION AND FLEXIBILITY

Parts of the synthetic kerosene production process run continuously, and parts run flexibly. Carbon capture (regardless of source) and kerosene synthesis run continuously. Carbon conversion, if necessary, runs continuously in the case of the RWGS route, but can be done flexibly with CO₂ electrolysis. Hydrogen production is very flexible, but not continuous if we use wind- and solar electricity exclusively. Given that both upstream (carbon capture) and downstream (kerosene synthesis) processes are continuous, this means we either need to produce hydrogen continuously (and at a roughly constant capacity) or install a hydrogen storage system. As every envisioned downstream process is continuous, storing a downstream intermediate product would still call for hydrogen storage or continuous production.

Since we want to use renewable electricity exclusively, we will have to incorporate a hydrogen storage facility to operate the kerosene production process smoothly. It is beneficial to have an overcapacity of hydrogen production beyond the total hydrogen required for production of a given quantity of kerosene; this allows us to minimize storage, as we would need significant storage capacity if operating below the required H₂ flow rate for an extended period. Any excess production beyond storage capacity can be sold to other industrial plants or users. At the same time, the additional PEM electrolyzers have a Full Load Hour dependent lifetime, so the stack will last longer, reducing depreciation. We therefore need to estimate the required size and costs of H₂ storage. We start with the former.

STORAGE SIZE

The exact quantity of hydrogen needed depends on the production pathway and the yearly amount of carbon as a starting point or yearly amount of kerosene as a final product. Suppose we produce p Mton synthesis products (kerosene, but also diesel if we follow the Fischer Tropsch route). For the Fischer Tropsch process, we can see from the chemical reaction (see Process chapter) and molar masses this means we require about p Mton $\cdot (2 \text{ g/mol} / 156 \text{ g/mol}) \cdot 23 = 23p/78$ Mton H₂. At a hydrogen production efficiency of 80%, we need about 50 TWh to produce 1 Mt of H₂. This means we would need $50 \text{ TWh/Mt} \cdot 23p/78 \text{ Mt} = 1150p/78$ TWh of electricity to produce the H₂ necessary for the FT step.

¹²⁶ CBS (2017): *Energy balance sheet; supply, transformation and consumption*

¹²⁷ CBS (2017): *Aviation; monthly figures of Dutch airports*

¹²⁸ M.A. Fütterer (2016). *Nuclear Power for the Production of Liquid Hydrocarbons. Institute for Energy and Transport. European Commission.*

¹²⁹ NREL (2016): *Review of Biojet Fuel Conversion Technologies*

Since the electrolyser only runs when there is sun or wind, its FLH and therefore the required capacity is determined by the FLH of wind and solar. Capacity factors in Danish offshore wind farms were on average 45.9%¹³⁰, translating to about 4,000 FLH, which we denote FLH_{wind}. Offshore wind is expected to achieve 4,800 FLH in the future¹³¹. The capacity factor used for solar panels in the Netherlands in the SDE calculations is 0.114, translating to 1,000 FLH, which we denote FLH_{sun}. We do not know to what extent these FLH of wind and solar overlap and to what extent they are complimentary. We can find the theoretical minimum for the electricity production capacity, just for this process, by assuming these FLHs are fully complimentary. The minimal required electricity production capacity, defined as yearly production over FLH, then equals $(1150p/78) \text{ TWh} / (FLH_{wind} + FLH_{sun}) \text{ hours} = (1,150p/78) / (4,000 + 1,000) \text{ TW} = 230p/78 \text{ GW}$. In practice, there will be simultaneous electricity production that might sometimes exceed electrolyser capacity, which is why this is the theoretical minimum. The total number of FLH will be between 4,000 (full overlap) and 5,000 (no overlap).

To get a better feeling of what p might be like, if we capture all available carbon from Tata Steel, these 3.1 Mt CO and 4.2 Mt CO₂ would result in almost 2.9 Mt FT products, so $p = 2.9$. This would thus require, at minimum, an electricity production capacity of $230p/78 = 8.4 \text{ GW}$ solely for this process. The hydrogen production capacity is $h \text{ GWe}$. We should have that $h > 230p/78 = 8.4 \text{ GWe}$, for two reasons. First, as said before, simultaneous electricity production at full load (sun and wind), hence at a capacity exceeding 8.4 GW will simply not contribute to this process and hydrogen production will fall short of the required amount. Second, if the hydrogen production capacity h is exactly equal to the correct electricity production capacity, hydrogen storage might be necessary



¹³⁰ Energy Numbers (2017): Capacity factors at Danish offshore wind farms

¹³¹ Fraunhofer Institute (2013): The importance of offshore wind energy in the energy sector and for the German energiewende

for very long periods – as the yearly production equals the required hydrogen for the FT process, but is not continuous. Therefore, as said before, a larger electrolyser capacity h is desirable; the maximum electricity production capacity, when FLH of solar and wind overlap completely (hence totalling 4,000), is $(1,150p/78)/4,000 \text{ TW} = (1,150 * 2.9 / 78) / 4 \text{ GW} = 10.6 \text{ GW}$. This is 26% more than the theoretical minimum of 8.4 GW. Given that full overlap is unlikelier than full complementarity, we will assume a safe 20% overcapacity.

With the above, we ensure there is enough electricity production and hydrogen production capacity to produce enough hydrogen each year for the FT process. To see how much storage we would need, we have to know more about the *continuous* hydrogen consumption of the FT process and the expected wind and solar electricity production profile of the greater energy system. To start with the former, we know we require $1,150p/78 \text{ TWh}$ of electricity to produce the hydrogen for the FT process each year. Since this FT process has 8,000 FLH, this hydrogen feed-in capacity requires an effective continuous electricity production of $1,150p/78 \text{ TWh} / 8,000 \text{ FLH} = 141p/78 \text{ GW}$. For $p = 2.9$, this equals $141 * 2.9 / 78 = 5.2 \text{ GW}$.

To find the required storage capacity, we need to identify the longest period in which, at times, electricity production would fall below this capacity of $141p/78 \text{ GW}$, but the average electricity production capacity equals this rate. For hydrogen production, the max electricity production is capped at the installed hydrogen production capacity h (in GWe). The area below (or above) that average would give the largest electricity 'shortage', which can be converted to the largest hydrogen 'shortage'. This then constitutes the minimum storage capacity s to run a continuous kerosene production process. It should be noted that this implicitly requires that this process has 'priority' over other electricity consumers. If that is not the case, we need to repeat this analysis for an electricity production capacity greater than $141p/78 \text{ GW}$; simply scaling the storage capacity does not work, as electricity production is volatile and non-linear.

It should be clear that although p is fixed, the electrolyser capacity h and storage capacity s are intimately related: the higher h , the lower s , and conversely. What is the best combination, depends on the investments one might wish to make and the availability of and competition for s ; if carbon capture is pursued in other plants, s might be restricted.

To estimate the shortage, we look at the solar and offshore wind profiles used by the Energy Transition Model with 15 GW wind and 2 GW solar electricity production capacity, operating 3,500 and 867 FLH respectively. We also work with a 20% overcapacity, so $h = 1.2 * (1150p/78) \text{ TWh} / (FLH_{wind} + FLH_{sun}) \text{ hours} = 1.2 * (1150 * 2.9/78) / (3500 + 867) \text{ TW} = 11.7 \text{ GW}$. To determine s , we find the longest period for electricity production capped at the electrolyser capacity of $h = 11.7 \text{ GW}$ to fall below the required continuous production of $141p/78 = 5.2 \text{ GW}$. This period is equivalent to an electricity

shortage of 5,550 GWh. In our system, where we assume greater FLHs (4,000 and 1,000, respectively), this shortage would have been smaller. With this electricity we can make $5,550 \text{ GWh} / 50 \text{ kt/GWh} = 111 \text{ kton H}_2$, which is the minimum size of our buffer. The volume required to store this amount of H_2 depends on the temperature and pressure. We assume hydrogen is stored at 100 bar in a salt cavern, where it has a density of almost 7.7 kt/Mm^3 (at 300 K)¹³², so it would occupy $110/7.7 = 14.3 \text{ Mm}^3$.

Pure hydrogen has been stored in salt caverns for decades, and at a 1 km top depth pressures are typically between 65 and 180 bar¹³³. H_2 storage in saline formations also seems the best large-scale storage option, as H_2 does not react with salts¹³⁴. TNO estimated the CO_2 storage potential in saline formations in the North Sea and arrived at a capacity of over 1,400 Mt¹³⁵, which at the assumed critical density of 700 kg/m^3 translates to a volume of about 2,000 Mm^3 . Hence, this hydrogen storage buffer would require about $14.3 \text{ Mm}^3 / 2,000 \text{ Mm}^3 = 0.7\%$ of that capacity. This shows that just a fraction of the total salt cavern storage options would suffice for a Mt-scale kerosene production process. Since the required cavern size is rather small, it may be interesting to first locate one or more caverns totalling this size and then decide on electrolyser capacity afterwards. In this light, the Hystock pilotproject where hydrogen produced with renewable electricity is stored in a salt cavern by Gasunie would be an interesting project to follow¹³⁶.

STORAGE COSTS

For storage in a salt cavern around Leeds, capital costs were 289M GBP for a 209 Mm^3 inter seasonal and 77 M GBP for a 1.2 Mm^3 intraday cavern. If we scale the investment costs of the intraday cavern¹³⁷ to our size of 14.3 Mm^3 , costs would have been 918 M GBP. These costs are in line with other sources, which quote 28 M€ / 0.5 Mm^3 (conservative range 20 - 50) for storage only, so 801 M€. Transmission systems in Leeds have costs of roughly 1 M GBP / km from deep salt cavity storage to end point. We will assume the transmission system would have a length of 30 km, resulting in 30 M GBP

costs (assuming the same costs/km). Over a 40-year lifetime, with O&M costs at 5% of CAPEX and the usual capital charge (described in this section) this evaluates to yearly running costs of about 75.4 M€/y.

In a more recent study on energy storage, the salt cavern storage efficiency was considered to be 0.9¹³⁹. We assume this includes hydrogen compression costs. To the costs above we have to add a compensation for efficiency losses in storage. We would then have to produce an additional $(1/0.9-1)$ factor of H_2 , so an additional $1/9 * 110 \text{ kton} = 12 \text{ kton H}_2$ each year. The costs of this hydrogen quantity have to be added to the yearly running costs of 75.4 M€/y. In a standard scenario, the total running costs then become 78 M€/y; as the H_2 production costs drop however, so do these running costs. These costs are about 1.5 - 4% of the total running costs of synthetic kerosene production, so rather low.

PROCESS INTEGRATION

The kerosene production chain can also be interconnected. Analysis of the entire synthetic kerosene production chain shows there is a net heat production. Since DAC uses low temperature heat, this heat could be supplied from the FT or alcohol upgrade step. We therefore model the DAC process step as having zero heat requirements.

Moreover, when CO is captured from Tata Steel, one has to take into account the economics of the current use of CO, as noted before. Currently, this is sold to NUON, where it is used to generate electricity. One way to value CO is to value the electricity one can generate with it. This is what we do in our modelling: we assume combustion of CO generates electricity with an efficiency of 40%, and electricity is valued at market price (here: the average). This value, expressed in €/ton CO, are added to CO capture costs. For more detail on process integration, we refer to the synthetic kerosene production model.

¹³² DOE (2017): Hydrogen Analysis Resource Center

¹³³ FCH (2013): Overview on all Known Underground Storage Technologies for Hydrogen

¹³⁴ Northern Gas Networks (2017): H21 Leeds City Gate

¹³⁵ TNO (2012): Independent assessment of high-capacity offshore CO_2 storage options

¹³⁶ Gasunie (2017): Aardgasbuffer Zuidwending. Van aardgasbuffer naar energiehub

¹³⁷ Northern Gas Networks (2017): H21 Leeds City Gate

¹³⁸ FCH (2013): Overview on all Known Underground Storage Technologies for Hydrogen

¹³⁹ 0.35 roundtrip efficiency, resulting from 0.65 electrolyser and 0.6 turbine. FCH (2014): Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe

FINANCIAL DEFINITIONS AND ASSUMPTIONS

CAPITAL CHARGE

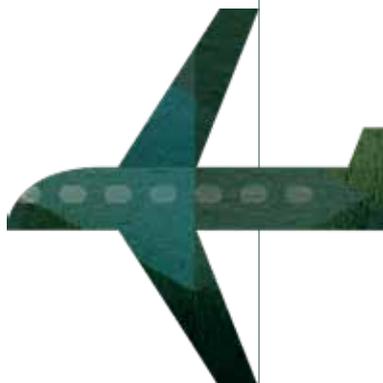
All investments (CAPEX) include a capital charge. We assume there is a 5% (compounded) interest and depreciation occurs linearly over 10 years.

BREAK-EVEN PRICE – COST & REVENUE

The break-even synthetic kerosene price is defined as the price which would make total annualised production costs equal to total annualised revenues; any greater kerosene price results in positive profits. Total annualised costs are the sum of total annualised costs of each process step for a given quantity of carbon as a starting point – or conversely a given yearly kerosene production. These annualised costs of a process step are the costs to obtain a tonne of the product of a step, calculated over its lifetime, including CAPEX, O&M costs, capital costs and utility costs. Total annualised revenues are the sum of all revenue streams. In the base scenario, these are sale of kerosene and diesel (if the FT route is chosen). This diesel, which is also synthetic, is sold for 1.2 times the fossil diesel price – i.e. we assume there is a 20% surcharge, as it has reduced chain emissions. One could argue that all FT products should be valued alike, but we believe the willingness and necessity to pay a fuel surplus is higher when there is no alternative (aviation) than when there is (cars, trucks). Whenever the cost ratio between fossil and synthetic kerosene falls below 1.5, we remove the synthetic diesel surplus cost. There are also additional revenue streams and avoided system costs, which we do not include in the base scenario but will discuss shortly and incorporate in some scenarios.

CO₂ ABATEMENT PRICE

The CO₂ abatement price is defined as the difference between the break-even synthetic kerosene price and the fossil kerosene price (in €/t) over the absolute value of the difference in CO₂ emissions (including fuel chain emissions) of combustion of 1 tonne of synthetic and 1 tonne of fossil kerosene.



SCENARIO A1: BASE PROJECTIONS, POINT SOURCE

DEFINITION

INPUT	
Carbon source	CC: 4.2 Mt CO ₂ , 3.1 Mt CO
Route	FT, PEM-CO ₂
Oil price	80 \$/bbl [base]
Electricity price	€0.04/kWh [base]
CAPEX tech	new Base projections
Revenues	Base

This scenario is based on technology and fuel projections entirely and serves as a reference scenario. The production process is modelled as described in the Process chapter, using base projections for CAPEX of new technologies. The carbon source is Tata Steel, with 4.2 Mt CO₂ and 3.1 Mt CO. Kerosene is produced using CO₂ electrolysis and FT synthesis and upgrading. We picked the FT pathway over the alcohol pathway for two reasons. First, we have a better understanding and better data on this process. Second, despite the relatively limited data on parts of the alcohol pathway, we can already see that the kerosene selectivity is in the range of 0.6-0.7 for methanol and 0.77 for ethanol. For FT, the diesel and fractions jointly make up a greater fraction, meaning revenues are typically higher (especially at a high oil price), which means the break-even price for kerosene is lower. If the oil price is not as high and the selectivity for AtJ quite high, it may be the better alternative. There is much uncertainty on this at present, which is why we work with the FT pathway for these business cases. Hence, we also need to select a carbon conversion technology. Although the RWGS has been employed more widely, the operational experience so far and possible scaling difficulty compared to the drop-in capacity and PEM benefits means we consider CO₂ electrolysis more favourably. Regarding electricity costs, it is assumed the average electricity price stays the same at €0.04/kWh. Revenues in this scenario are base revenues, i.e. kerosene and diesel sale only.

To compare synthetic kerosene with fossil kerosene, we also have to estimate the latter's price in 2030. These costs are based on the crude oil price and refining costs. For the oil price, we use the World Bank's projection for the year 2030, 80 \$/bbl¹⁴⁰. Refining costs are assumed to stay at current levels, i.e. € 0.053/l¹⁴¹, slightly below American prices of 15 \$/bbl for diesel¹⁴². At the €/€ exchange rate of 1.18 we use throughout, this means, fossil kerosene costs 80\$/bbl / (159 l/bbl) / 1.18 €/€ + € 0.053/l = € 0.48/l.

OUTPUT	
PtL kerosene cost	1292 €/t 195 \$/bbl
Fossil kerosene cost	596 €/t 90 \$/bbl
Ratio	2.17
CO ₂ abatement cost	€ 112 / t CO ₂

OUTPUT

For every scenario, we display key output parameters in an 'output' table like the one above. They include synthetic kerosene and fossil kerosene cost, both without taxes, the ratio between these two and the CO₂ abatement costs. Kerosene costs are expressed both in €/t and in \$/bbl, using the density of 0.804 kg/l and €/€ exchange rate of 1.18.

In this base scenario, the break-even price for synthetic kerosene is 1292 €/t or 195 \$/bbl, while the fossil kerosene price is 596 €/t or 90\$/bbl. This means their ratio is 2.17. Both are an increase from the current kerosene price, which based on the November 2017 oil price of 63\$/bbl, would be about 78\$/bbl. Total CO₂ emissions saved are about 11 Mton, or 55%. The CO₂ abatement cost in this reference scenario are € 111 /t CO₂, which would put it high up in a CO₂ abatement cost curve¹⁴³. Such a CO₂ abatement curve does not take into account the difficulty of CO₂ abatement in a certain sector; if no alternative CO₂ reduction measure is available, that might justify higher costs. This is just a reference scenario; CO₂ abatement costs, as well as kerosene cost, might turn out significantly higher or lower. After estimating the impact on consumer flight ticket price, we will consider several other scenarios.

¹⁴⁰ World Bank (April 2017): World Bank Commodities Price Forecast

¹⁴¹ Shell in Taxi Magazine (2014): Hoe komt de brandstofprijis tot stand

¹⁴² Colorado School of Mines (2017): Petroleum Refining Overview

¹⁴³ Task GHG (2016): Mitigation Cost Curves

IMPACT ON CONSUMER- FLIGHT TICKET PRICE

An interesting question, which makes this scenario output perhaps more relatable, is what impact a kerosene price increase would have on the costs of a flight ticket. Flight tickets should be priced such that they are slightly more expensive than operating expenses of airline companies. For Ryanair, kerosene comprises 37% - 41% of the yearly Operating Expenditure (OPEX) in the last two years¹⁴⁴. For KLM, less than 25%¹⁴⁵. The industry average in 2015 was 24.3% at an average oil price of \$53.9/bbl¹⁴⁶, with budget airlines probably having a greater fraction and upscale airlines a smaller fraction.

This means that fuel costs are probably between, say, 20% and 45% of an airline's OPEX. Given that there is a profit margin, we estimate the fuel fraction of a ticket price to be between 15% and 40%. This depends on many factors, including flight distance, wind speeds, occupancy, operator etc. In general, we may expect budget airlines to have greater fuel shares.

If we assume that all costs other than fuel stay equal, it is clear that ticket prices will increase based on this scenario, regardless of whether planes are flown on fossil or synthetic kerosene. With the 2015 average oil price of \$53.9/bbl and refining costs of 15\$/bbl, the average fossil kerosene price in 2015 would be an estimated 69.9\$/bbl. If one flies on fossil kerosene in 2030, fuel costs increase with 29% to 90\$/bbl; if synthetic kerosene is chosen, the increase is 180%. This means the yearly OPEX fraction would increase from 24.3% (current fossil kerosene) to 31.3% (future fossil kerosene) and to 67.7% (future synthetic kerosene), respectively; this means new ticket prices would be less than (since profit should not be scaled) 107% and 143% of 2015 ticket prices, respectively. If we correct for profits, we see that ticket costs would rise 5% and 40% with respect to 2015 levels. In 2030, tickets for synthetic fuel flights would then be $140\%/105\% = 133\%$ of fossil fuel tickets. This excludes CO₂ taxes and is based on this scenario only.



¹⁴⁴ Ryanair (2017): Annual Report

¹⁴⁵ KLM (2017): Annual Report 2016

¹⁴⁶ IATA (2017): Fact Sheet - Fuel

For an airline with low relative fuel costs like KLM, ticket costs would be less than 33% higher. If 15% of ticket costs are fuel costs, and they increase as detailed above (29% and 180%), the rescaled fractions are 19% and 42%, so total costs 104% to 127% of 2015 levels (including scaled profits). Synthetic kerosene tickets in 2030 would then be less than $127\% / 104\% = 122\%$ of fossil kerosene tickets in 2030. For an airline with high relative fuel costs like Ryanair, tickets costs would increase much more. If 40% of ticket costs are fuel costs, and they increase as detailed above (29% and 180%), the rescaled fractions are 52% and 112%, so total costs 112% to 172% of 2015 levels (including scaled profits). Synthetic kerosene tickets in 2030 would then be less than $172\% / 112\% = 154\%$ of fossil kerosene tickets in 2030.

In short, as crude oil prices rise, flight ticket prices will also increase. The relative increase will be rather small for airline operators with low fuel OPEX, but high for those with high fuel OPEX. By the same mechanism, ticket surplus costs for synthetic fuel that is 2.17 times as expensive as fossil kerosene (at 90\$/bbl) are low (e.g. 20%) for airlines with low fuel OPEX, but high (e.g. 50%) for airlines with high fuel OPEX. The consumer would thus observe a small to significant ticket price increase in this scenario, depending on flight and operator.

MAIN SENSITIVITIES AND UNCERTAINTIES

From the 'Process' chapter as well as the synthetic kerosene production model, it has become clear there are a few parameters that largely determine the price difference between fossil and synthetic kerosene as well as the CO₂ abatement costs. These parameters are typically also very volatile or otherwise uncertain. This combination of high impact and large uncertainty, means they will be the main factors in the business case. These parameters are the crude oil price, electricity price and the techno-economic development of several new technologies. For each parameter, we will discuss its impact and uncertainty, as well as the ranges we will work with. Lastly, we will make one change to Scenario A for each upper and lower bound of each parameter to show its impact.

CRUDE OIL PRICE

HIGH IMPACT AND LARGE UNCERTAINTY

One parameter is the crude oil price. Clearly it is high impact, as a doubling of the crude oil price would directly pretty much halve the synthetic kerosene - fossil kerosene price ratio. It is also very volatile. At the moment of writing (20/11/2017), the Brent crude oil price is 61.34 \$/bbl, but this year alone it has been between 44 and 63 \$/bbl. In the past 10 years it has been between 30\$/bbl and 144\$/bbl¹⁴⁷. When oil is at the highest price, synthetic kerosene produced from waste gases with current technology is already competitive. When oil is at its current or an even lower price, more developments on the site of electricity production, hydrogen production and synthetic kerosene production are required.

RANGES

As we saw in the last paragraph, the oil price has been between 30 and 144\$/bbl in the past decade. Historic ranges do not necessarily encompass future prices, so one could argue we need to extend them. We will not do that, but work with a crude oil price between 30\$/bbl and 144\$/bbl. It is unlikely the oil price will fall below this minimum, given society's path to become carbon neutral and economic mechanisms. At this maximum, synthetic kerosene is already competitive in most circumstances, so this will serve as an upper bound; (only) if the other high impact parameters (electricity price and CAPEX' new technologies) discussed below are at the top of their ranges, synthetic kerosene will be about twice as expensive. This is still quite close, especially since this excludes carbon and other taxes.

SCENARIO IMPACT - UPPER BOUND



¹⁴⁷ EIA (2017): Petroleum & Other Liquids. Europe Brent Spot Price

Setting the crude oil price to 144 \$/bbl results in the output

OUTPUT		
PtL kerosene cost	1104 €/t	167 \$/bbl
Fossil kerosene cost	1021 €/t	154 \$/bbl
Ratio	1.08	
CO ₂ abatement cost	€ 13 / t CO ₂	

parameters displayed above (combined with setting the synthetic diesel price equal to the fossil diesel price). All other parameters at base projections, this means that synthetic kerosene is almost at parity with fossil kerosene. As a result, CO₂ abatement cost are also very low. The reason synthetic kerosene costs have decreased is that the revenues from diesel sale have increased.

SCENARIO IMPACT - LOWER BOUND

OUTPUT		
PtL kerosene cost	1537 €/t	232 \$/bbl
Fossil kerosene cost	265 €/t	265 €/t
Ratio	5.80	
CO ₂ abatement cost	€ 205 / t CO ₂	

Setting the crude oil price to 30 \$/bbl results in the output parameters displayed above. The ratio now is very unfavourable, and CO₂ abatement cost significant. The reason synthetic kerosene costs have increased is that the revenues from diesel sale have decreased.

ELECTRICITY PRICE

HIGH IMPACT AND LARGE UNCERTAINTY

The second parameter is the electricity price. From a very high level, synthetic kerosene production costs are mostly driven by hydrogen production (approx. 65-80%, depending on efficiency and electrolyser CAPEX), which in turn is driven by electricity cost (approx. 70-90%), so the overall cost are determined for 45-72% by electricity for hydrogen production alone. If we add running cost of other processes, this fraction is roughly between 60-90%. This means that halving the average electricity price would reduce synthetic kerosene costs by 30-45% - a very large impact. Electricity production from renewable sources such as solar or wind is inherently volatile; as a consequence, so are the resulting electricity prices. Electricity consumption, too, is very irregular but obeys certain patterns. There is however a lot of uncertainty about future electricity consumption, which is dependent on to what extent, at what speed and in what topology various sectors will demand electricity.

RANGES

The average electricity price depends a lot on the location one considers. Since we focus on the Netherlands, we will also describe electricity price ranges for the Dutch market. The current market is based on a merit order of marginal costs of the installed electricity generation plants. In practice, the yearly average electricity price is about € 0.04/kWh. The marginal costs of wind and solar electricity are very low, whereas fossil electricity requires fuels and comes at higher prices. It is unclear how much consumption will take up. We will work with 50% uncertainty in the yearly average electricity price, hence it will be between € 0.02/kWh and € 0.06/kWh. At the lower limit, there is a large renewable electricity generation capacity which exceeds or meets electricity demand (if excess electricity is used); at the higher limit, the electricity consumption will have increased rapidly, raising costs. It is quite likely, the true average will be in this range, but we do not know the electricity price distribution. The way in which we model this is discussed in greater detail in the business case chapter.

SCENARIO IMPACT - UPPER BOUND

OUTPUT		
PtL kerosene cost	1947 €/t	294 \$/bbl
Fossil kerosene cost	596 €/t	90 \$/bbl
Ratio	3.26	
CO ₂ abatement cost	€ 218 / t CO ₂	

Setting the electricity price to € 0.06/kWh results in the output parameters displayed above. PtL kerosene costs increase significantly, as do the ratio and CO₂ abatement costs. Fossil kerosene costs do not change in this scenario.

SCENARIO IMPACT - LOWER BOUND

OUTPUT		
PtL kerosene cost	711 €/t	107 \$/bbl
Fossil kerosene cost	596 €/t	90 \$/bbl
Ratio	1.19	
CO ₂ abatement cost	€ 18 / t CO ₂	

Setting the electricity price to € 0.02/kWh results in the output parameters displayed above (combined with setting the synthetic diesel price equal to the fossil diesel price). The ratio now is more favourable, and CO₂ abatement cost relatively low.

SCENARIO IMPACT - EXCESS ELECTRICITY

OUTPUT		
PtL kerosene cost	1029 €/t	155 \$/bbl
Fossil kerosene cost	596 €/t	90 \$/bbl
Ratio	1.73	
CO ₂ abatement cost	€ 69 / t CO ₂	

With the increase of wind electricity production capacity, at times electricity production might exceed demand. This production process allows to store this hydrogen via power-to-gas (PtG). To illustrate the impact of operation with excess electricity, we consider a scenario in which electrolyzers only run on excess electricity (the rest of the process, of course, remains continuous). This means we also require a larger hydrogen storage capacity. If we could have access to excess electricity for 10% of the year for € 0.01/kWh (the other 90% of the time the electrolyzers are sitting idle (so FLH are 876 hours) and storage costs are doubled, this results in the output parameters displayed above. This leads a noticeable reduction in PtL kerosene costs, but it remains to be seen which party or process has the right or priority to use such excess electricity. It is therefore an unlikely scenario, but does illustrate the costs and ability of this process.

SCENARIO IMPACT - QATAR

OUTPUT		
PtL kerosene cost	547 €/t	83 \$/bbl
Fossil kerosene cost	596 €/t	90 \$/bbl
Ratio	0.92	
CO ₂ abatement cost	- € 8 / t CO ₂	

In October 2017, EDF and Masdar put out a record-low bid of \$0.0178/ kWh for a utility-scale solar plant¹⁴⁹, or about €0.015/kWh. Whether carbon and water will be readily available in this location (desalination being an energy-intensive process) is something that would have to be looked into. If we however assume carbon (from flue gases) and water are available in large quantities, kerosene production in Qatar could lead to the output parameters above. At these electricity price levels (combined with setting the synthetic diesel price equal to the fossil diesel price), synthetic kerosene is already cheaper than fossil kerosene, excluding taxes. We suggest follow-up research is necessary to indicate to what extent carbon and water are available at these locations, to what extent export of the resulting hydrogen and/or PtL liquids is to be expected and at what cost for transportation to Europe. If hydrocarbons are produced, they could be distributed via existing supply chains. If hydrogen is produced, they could be distributed liquefied via ships or via a H₂ grid. Either way, this option would provide a huge competitive advantage to airlines from the Middle East if oil prices are expected to rise and/or true CO₂ emissions are to be taxed in the aviation industry.

SCALING & CAPITAL COSTS NEW TECHNOLOGIES

HIGH IMPACT AND LARGE UNCERTAINTY

The last parameter is a family: the future techno-economics of new technologies. Although virtually all technologies are already at TRL 6 or 7 and many elaborate estimates of future techno-economics have been presented by the companies developing them, it still remains to be seen whether they scale and are developed to indeed achieve these techno-economics. This uncertainty, mainly in CAPEX, is reflected in rather different synthetic kerosene prices, although it should be noted the impact is not as great as that of the two aforementioned parameters (oil & electricity price). An optimistic or pessimistic view on the development can thus result in a rather different kerosene price - push it closer to parity or further away.

¹⁴⁹ Khaleej Times (2017): Masdar, EDF Energies lead bidding for Saudi solar plant

RANGES

We propose to use fixed-percentage uncertainties for the CAPEX of several new technologies. These technologies are: carbon capture (CO₂ and CO), DAC, PEM (water and CO₂) and methanol upgrade. The ranges we propose are +- 50%.

SCENARIO IMPACT - UPPER BOUND

OUTPUT		
PtL kerosene cost	1436 €/t	217 \$/bbl
Fossil kerosene cost	596 €/t	90 \$/bbl
Ratio	2.41	
CO ₂ abatement cost	€ 135 / t CO ₂	

Increasing CAPEX of aforementioned technologies by 50% results in the output parameters above. The ratio is now more unfavourable, but not very significantly so.

SCENARIO IMPACT - LOWER BOUND

OUTPUT		
PtL kerosene cost	1148 €/t	173 \$/bbl
Fossil kerosene cost	596 €/t	90 \$/bbl
Ratio	1.93	
CO ₂ abatement cost	€ 188 / t CO ₂	

Decreasing CAPEX of aforementioned technologies by 50% results in the output parameters above. The ratio is now more favourable, but not very significantly so.



SCENARIO A2: PARITY WITH PLAUSIBLE ASSUMPTIONS, POINT SOURCE

DEFINITION

INPUT	
Carbon source	CC: 4.2 Mt CO ₂ , 3.1 Mt CO
Route	FT, PEM-CO ₂
Oil price	108 \$/bbl (incl. CO ₂ tax)
Electricity price	€0.029/kWh
CAPEX new tech	Base projections
Revenues	Base + oxygen sale

To illustrate what would be required to reach parity between fossil and synthetic kerosene, we tried to construct a scenario based on the reference scenario, without any extreme assumptions. In this scenario, the synthetic diesel price is also set equal to the fossil diesel price (i.e. there are no longer surplus costs). The input for this scenario is shown on the right. It is worth noting that no deviation greater than 35% from base scenario prices is required. There are four modifications.

1. The oil price is increased from 80\$/bbl to 98\$/bbl. The oil price can fluctuate strongly, and has far exceeded these price levels, for extended periods in the past.

2. A CO₂-tax of 20€/t is added to the crude oil price. 1 bbl crude oil is equivalent to 159 l * 0.82 kg/l = 130 kg crude oil. With an energy density of 42 MJ/kg and emissions of 0.0755 kg CO₂ / MJ¹⁵⁰, combustion of 1 barrel would emit 130 kg * 42 MJ/kg * 0.0755 kg/MJ = 0.41 ton CO₂. This therefore adds 20 €/t * 0.41 t = 8.2 €/bbl, or 8.2 * 1.18 \$/€ = 9.68\$/bbl to the crude oil price. This would mean the total crude oil price including CO₂ tax is 107.68 \$/bbl.

¹⁵⁰ JRC (2011): *Well-to-wheels Analysis of Future Automotive Fuels and Powertrains in the European Context*. WTT Appendix 1.

3. The average electricity price is decreased from € 0.04/kWh to € 0.029/kWh. In July 2016, an offshore wind farm tender in the Netherlands was won at € 72.7/MWh; in December that same year, a tender for an adjacent area (the same site) was won at € 54.4/MWh¹⁵¹. This shows a strong belief in techno-economic improvements, as geographical differences are negligible. Neither is currently a record low, and prices are expected to fall further. The current worldwide record low is \$17.7/MWh (or less than € 0.015/kWh), for wind in Mexico¹⁵². A 2017 McKinsey study estimated the levelised cost of electricity (LCOE) of offshore wind farms in the Netherlands to reach € 31-37/ MWh, in 2020¹⁵³. For our reference year of 2030, it may be expected prices will have dropped even more. Hence, we work with an average renewable electricity price (mostly wind) of € 29/MWh.

4. Oxygen, produced as a byproduct in water and CO₂ electrolysis, can be sold to other industrial plants to generate additional revenue. In fact, the steel industry is one of the largest industrial consumers of oxygen¹⁵⁴. Currently, Tata Steel produces oxygen itself through cryogenic air separation¹⁵⁵. We assume that we can sell the oxygen produced through electrolysis for production costs of cryogenic separation. Tata's oxygen demand can be estimated based on the production process info presented earlier and¹⁵⁶¹⁵⁷. We assume the remainder of O₂ can also be sold for the same price. The exact calculations and modelling of this can be found in the synthetic kerosene production model.

All other parameters are as described in the base scenario.

OUTPUT		
PtL kerosene cost	782 €/t	118 \$/bbl
Fossil kerosene cost	782 €/t	118 \$/bbl
Ratio	1.00	
CO ₂ abatement cost	€ 0 / t CO ₂	

These input parameters result in parity between synthetic and fossil kerosene cost, which also means the CO₂ abatement costs are zero.

¹⁵¹ Wind Europe (2017): *Record-low bids in offshore wind should make policy makers rethink post-2020 ambition levels*

¹⁵² Windpower Engineering (2017): *Enel sets a new world wind record in Mexico, below \$18/MWh*

¹⁵³ McKinsey (2017): *Winds of change? Why offshore wind might be the next big thing*

¹⁵⁴ Gasworld (2007): *Oxygen global market report*

¹⁵⁵ B. Daniels (2002): *Transition paths toward CO₂ emission reduction in the steel industry*

¹⁵⁶ L. Hooey et al. (2013): *Techno-economic study of an integrated steelworks equipped with oxygen blast furnace and CO₂ capture*. Energy Procedia 37, 7139 - 7151
¹⁵⁷ IEA GHG (2013): *Iron and Steel CCS Study (Techno-Economics Integrated Steel Mill)*

ADDITIONAL SOCIETAL BENEFITS

Besides the CO₂ reductions, this business case also confers some benefits for society at large.

First, a Mt size kerosene production plant in North Holland would eliminate or reduce the need to build high voltage electricity grid infrastructure to transport electricity elsewhere inlands. HV grid expansion costs estimated at 5 M€ / 2.5 GW wind capacity / km grid expansion would be avoided. The exact length of such an expansion depends on the extent to which the Dutch energy system electrifies; it is likely it will run into tens of kms. At 15 GW and 50 km additional expansion (on top of landing in IJmuiden), this amounts to 1.5 billion euro. If this electricity would need to be transported further to e.g. the border of Belgium (~ 150 km), the associated costs would be approximately 4.5 billion.

Second, it eliminates the need and costs to store Tata Steel's CO₂. Tata Steel can choose what to do with its waste gases, but at this point it is clear it will not simply continue emitting them in the long term. Hence, Tata Steel has to choose whether to store or utilise (of which kerosene production is one example) them. Regardless, some waste gas components will be captured. If they are then utilised rather than stored, one avoids the need and costs to store CO₂. Especially since hydrogen is best stored in salt caverns, this would also avoid using storage options that could be used flexibly.

Third, synthetic kerosene will most probably have a less volatile price than fossil kerosene. Many airline companies compete for margins and, be it consciously or unconsciously, underestimate operational risk due to extreme volatility of the crude oil price. At the high oil prices in 2008, one US airline company went out of business each week, mainly due to fuel costs¹⁵⁸. When UK airline Monarch fell in 2017, 110,000 people needed to be flown back at a 60M GBP cost, some 700,000 future bookings were cancelled and 2,100 employees were to lose their jobs¹⁵⁹. We have not tried to estimate the avoided cost from this decrease in operational risk, but it seems safe to say it is better to fly with a less volatile fuel price.

If these benefits are featured in (avoidance of CO₂ transport and storage as well as investments in 150 km of HV grid extension), parity would be achieved as described in scenario A2, with an electricity price of € 33/MWh or an oil price of \$95/bbl already. Lastly, the avoided long-term damages to the world might diminish all other numbers quoted here.

¹⁵⁸ The Guardian (2008): Fuel costs kill off a US airline every week

¹⁵⁹ The Guardian (2017): Monarch Airlines collapse: UK's biggest peacetime repatriation under way.

SCENARIO B1: BASE PROJECTIONS, DAC

DEFINITION

This is another reference scenario, identical to scenario A1, with the exception that all carbon is captured from the air via DAC rather than from Tata Steel. To produce the same quantity of kerosene, this requires a yearly capture of 9.1 Mt CO₂.

INPUT	
Carbon source	DAC: 9.1 Mt CO ₂
Route	FT, PEM-CO ₂
Oil price	80 \$/bbl [base]
Electricity price	€0.04/kWh [base]
CAPEX new tech	Base projections
Revenues	Base

OUTPUT		
PtL kerosene cost	1762 €/t	266 \$/bbl
Fossil kerosene cost	596 €/t	90 \$/bbl
Ratio	2.95	
CO ₂ abatement cost	€ 188 / t CO ₂	

Compared to reference scenario A1 we notice two differences in output. First, the costs of synthetic kerosene are higher when the carbon source is the ambient air. Second, the CO₂ abatement costs of such kerosene are higher than those of synthetic kerosene made from flue gases. In the flue gases case, we achieve an approximately 9 Mt or 45% emission reduction in the longer chain from coal to propeller (via the steelplant). In the air capture case, we achieve a 9 Mt or 100% emission reduction in the shorter (cyclic) chain from air to propeller. In both cases an additional 2 Mt emissions of refinery losses are avoided, so total emission savings are about 11 Mt (55% emission reduction) in each case. Direct air capture being costlier, this means CO₂ abatement costs are higher, although a 100% reduction is achieved.

SCENARIO B2: PARITY WITH PLAUSIBLE ASSUMPTIONS, DAC

DEFINITION

INPUT	
Carbon source	CC: 4.2 Mt CO ₂ , 3.1 Mt CO
Route	FT, PEM-CO ₂
Oil price	118.5 \$/bbl (incl. CO ₂ tax)
Electricity price	€0.02/kWh
CAPEX new tech	Base projections
Revenues	Base + oxygen sale

To illustrate what would be required to reach parity between fossil and synthetic kerosene from the ambient air, we tried to construct a scenario based on the reference scenario (B1). In this scenario, the synthetic diesel price is also set equal to the fossil diesel price (i.e. there are no longer surplus costs). The input for this scenario is shown on the right. No deviation greater than 50% from base scenario prices is required. There are three modifications.

1. The oil price is increased with 32% from 80\$/bbl to 104\$/bbl. This price is higher than before, but not inconceivably much (especially historically).
2. A CO₂-tax of 30€/t is added to the crude oil price. Repeating the calculation, we find this adds 30 €/t * 0.41 t = 12.3 €/bbl, or 12.3 * 1.18 \$/€ = 14.5\$/bbl to the crude oil price. This would mean the total crude oil price including CO₂ tax is 118.5 \$/bbl.
3. The average electricity price is decreased with 50% from € 0.04/kWh to € 0.02/kWh. Given the expected LCOE of offshore wind farms in the Netherlands of € 31-37/ MWh in 2020, this may seem like a pretty steep drop that is required to 2030. However, giving the Mexican offshore tender won at €15/MWh, a price of €20/MWh definitely does not seem impossible.
4. Sale of oxygen, produced as a byproduct in water and CO₂ electrolysis, for production price, as before in scenario A2. Given that we need to electrolyse more CO₂ in this scenario than in A2, oxygen revenues will be higher.

All other parameters are as described in the base scenario.

OUTPUT		
PtL kerosene cost	852 €/t	130 \$/bbl
Fossil kerosene cost	852 €/t	130 \$/bbl
Ratio	1.00	
CO ₂ abatement cost	€ 0 / t CO ₂	

These input parameters result in parity between synthetic and fossil kerosene cost, which also means the CO₂ abatement costs are zero. As can be expected, the kerosene price in this scenario is higher than in the parity scenario with point source carbon, scenario A2.



COMPARISON SYNTHETIC, BIO-BASED AND FOSSIL KEROSENE

After having investigated possible synthetic kerosene productions chains to greater depth, we now make an integral climactic comparison between three types of kerosene: fossil, bio-based and synthetic kerosene. This integral climactic comparison will evaluate water use, land use and, most importantly, greenhouse gas emissions of each product's life cycle. For fossil kerosene, we consider crude oil imported from Saudi Arabia and refined in Rotterdam. For bio-based kerosene, these parameters differ strongly depending on feedstock. We therefore consider the 'best' and an 'average' feedstock, which can be grown in the Netherlands. We will consider bio-based kerosene from short rotating wood crops (SRWC) such as poplar and from rapeseed and take values from existing literature. For synthetic kerosene, we will consider kerosene produced from carbon from waste gases exclusively and from carbon obtained through DAC exclusively. It is assumed all pathways are of such size they produce as much kerosene as can be produced from Tata Steel's waste gases via the pathway described in scenario A. This amounts to 1.75 Mt or about 75 PJ kerosene.

INDICATORS

WATER USE

FOSSIL

A refinery uses water for cooling and process purposes, totalling 1 to 2.5 litres of water for every litre of product¹⁶⁰. With kerosene having a density of 0.804 kg/l and energy density of 43.15 MJ/kg, this is equivalent to 1 to 2.5 litres of water for every $0.804 \times 43.15 = 34.7$ MJ; hence, 0.0288 to 0.072 m³ per GJ kerosene.

SYNTHETIC

Water is used for synthetic kerosene production in electrolysis, to produce the hydrogen necessary for refining steps. This amounts to about 0.04 m³ per GJ kerosene¹⁶¹.

LAND USE

FOSSIL

To estimate the land use for fossil kerosene production, we scale a reference plant to our size. Shell's Pernis refinery in the Netherlands processes 404k bbl/d and occupies 550 ha¹⁶². This area includes refining as well chemical processes. If we scale this area to the capacity of our process (72 k bbl/d), it would be 98 ha. From this we would have to subtract the area used for production of chemicals and add the area in Saudi Arabia used for terminals and crude oil extraction. We estimate the net result of that calculation to be 150 ha. With a 75 PJ production, this equates to land requirements of 0.02 ha/GJ kerosene.

SYNTHETIC

Land use for the synthetic kerosene production chain under characterisation comprises land for: carbon capture / DAC, water electrolysis, CO₂ electrolysis and FT synthesis and upgrading. The electrolyzers are modular; Siemens has designed a 300 MW electrolyzer which occupies roughly 180m * 80m = 1.5 ha¹⁶³. At 10 GW electrolysis and 1.9 GW CO₂ electrolysis, we need about 11.9 GW / 0.3 GW * 1.5 ha = 60 ha. Other parts of the production process are non-modular. For FT synthesis and upgrading, we scale a reference plant to our size. The Shell Pearl GTL plant with a GTL capacity of 140 k bbl/d occupies an area the size of New York's Central Park, i.e. 341 ha¹⁶⁴. Our FT process produces 72 k bbl/d, and does not include a gasification part. It should therefore not occupy an area greater than 170 ha. This brings the total area

¹⁶⁰ EPA (2015): *Water & Energy Efficiency by Sectors. Oil Refineries*

¹⁶¹ Umwelt Bundesamt (2016): *Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

¹⁶² Shell Nederland (2017): *Shell Pernis*

¹⁶³ This was disclosed by Siemens at the Oil and Gas Reinvented Conference, held on 9/11/2017 at the Shell Technology Centre Amsterdam

¹⁶⁴ Shell (2015): *Schonere lucht voor iedereen*

without carbon capture to less than 230 ha. The area required for carbon capture from Tata Steel's flue gases should be less than that of a natural gas gasifier, so the total area required in the case of carbon capture from a point source would be approximately 230 ha.

DAC, in the case of Climeworks, is modular. Climeworks' current 0.9 kt CO₂/y plant measures 90 m²¹⁶⁵. To produce as much kerosene as can be produced from Tata's waste gases, we need a 9.1 Mt CO₂/y capacity. This would occupy 10,100 times as much space, or 91 ha. It should be kept in mind that these units should be positioned such that the CO₂ deprived gases are not blown into other units, as that would result in a significant efficiency penalty. We estimate the total size to be 321 ha at most, but probably around 300 ha if we compensate for Shell's gasifier. With a 75 PJ kerosene production, this brings land requirements to 0.031 and 0.043 m²/GJ, for Tata and DAC, respectively. It should be noted that this does not include electricity generation, which is outside the system boundaries.

GREENHOUSE GAS EMISSIONS

Values for the life cycle emissions of fossil kerosene are obtained from¹⁶⁶ and consistent with others¹⁶⁷. For synthetic kerosene, values are calculated by the synthetic kerosene model.

COSTS

Costs for bio-based kerosene from SRWC (poplar) are 1.00 – 1.14 \$/l¹⁶⁸. Costs for fossil and PtL kerosene are determined by the ranges that are under consideration (see 'Main Sensitivities and Uncertainties' chapter).

¹⁶⁵ Climeworks (2017): *World-first Climeworks plant: Capturing CO₂ from air to boost growing vegetables*

¹⁶⁶ Umwelt Bundesamt (2016): *Power-to-Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.*

¹⁶⁷ MIT (2016): *LCA of current and future ghg emissions from petroleum jet fuel*

¹⁶⁸ J.T. Crawford et al. (2016): *Hydrocarbon bio-jet fuel from bioconversion of poplar biomass: techno-economic assessment. Biotechnology for Biofuels, 9 (141)*



OVERVIEW

Indicator \ kerosene	Fossil	Bio ¹⁶⁹ (poplar)	Bio (rapeseed) ¹⁷⁰	Ptl (Tata)	Ptl (DAC)
Water usage (m ³ /GJ)	0.03 – 0.07	112	165	0.04	0.04
Land usage (m ² /GJ)	0.02	58-213	208	0.03	0.04
Emissions (g CO ₂ /MJ)	87.5 – 89.1	32 - 73 ¹⁷¹	54.9 – 97.9	40.8	0 ¹⁷²
Costs (€/l)	0.21 – 0.82 [0.48]	0.85 – 0.97		0.25 – 1.88 [1.04]	0.53 – 2.49 [1.43]

Table 1: Comparison fossil, bio-based and synthetic kerosene. Values in square brackets are references values obtained from scenarios A1 and B1.

It is clear that synthetic and fossil kerosene demand similar quantities of water and land, whereas bio-based kerosene produced from crop grown in the Netherlands requires more than 1,000 times more water and arable land. Emissions from fossil kerosene are most significant, although bio-based kerosene has about half to slightly greater emissions, depending on feedstock and calculation method. Synthetic kerosene from waste gases emits just below half of fossil kerosene, and this quantity is not subject to as much uncertainty as that of bio-based kerosene. Only when kerosene is produced from carbon obtained through DAC, emissions can truly approach zero. Based on these three indicators, it is clear synthetic kerosene is the best.

When we feature in the costs, the situation does not change much for bio-based kerosene. It is more expensive than fossil kerosene, even when the oil price is at 140\$/bbl. Because a sizeable share of costs is feedstock related and these costs are not expected to come down when scaled up, it seems

fair to say that bio-based kerosene will most likely also stay more expensive than fossil kerosene. The same cannot be said of synthetic kerosene, which does have the potential to reach parity with or even become more affordable than fossil kerosene, given favourable conditions (e.g. low electricity price). If conditions are unfavourable however (e.g. high electricity price), synthetic kerosene is a few factors away from parity, and more expensive than bio-based kerosene.

In this comparison we have not yet taken into account additional benefits of PtL which have been mentioned before, nor quantified CO₂ prices or taxes. Given the strong advantages synthetic kerosene has over the alternatives, we believe that incentives should and will be put in place to reduce the additional costs of synthetic over fossil kerosene, if present.

¹⁶⁹ Umwelt Bundesamt (2016): Power-to- Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.

¹⁷⁰ Umwelt Bundesamt (2016): Power-to- Liquids Potentials and Perspectives for the Future Supply of Renewable Aviation Fuel.

¹⁷¹ E. Budsberg et al (2016): Hydrocarbon bio-jet fuel from bioconversion of poplar biomass: life cycle assessment. *Biotechnology for Biofuels*, 9 (170),

¹⁷² 'Running emissions', excluding plant construction

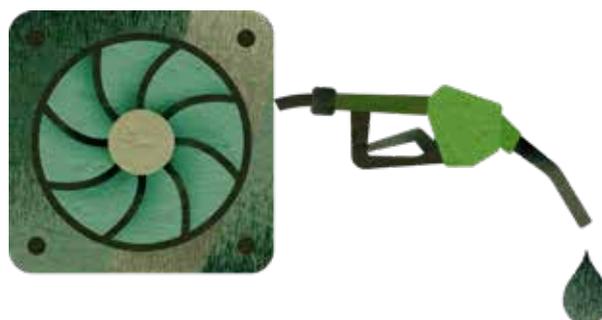
CONCLUSION

It seems safe to say that although the advent of electric technology in aviation seems quite distant still, a carbon neutral solution is within reach, even available. The entire synthetic, carbon neutral kerosene production chain has been demonstrated on various occasions and via various routes. Most process steps remain to be scaled and some to be improved, but it is most likely that the next decade will be the start of mass-scale synthetic fuel production – Lanzatech and the Norwegian Blue Crude being some of the first to already announce such plants. The first commercial plants will most likely rely mostly on carbon from flue gases rather than the ambient air, but these roles will reverse as DAC is developed further – until DAC alone provides all carbon for synthetic kerosene production.

Focusing on the Netherlands and North Holland specifically, we found the IJmuiden and greater Amsterdam area to be locations well-suited for synthetic kerosene production for their proximity to renewable electricity production, concentrated carbon sources and kerosene transport, storage and consumption sites. We further saw that the capture potential from Tata Steel’s waste gases is sufficient to produce 1.75 Mt or 75 PJ or 50% of Schiphol’s kerosene consumption in 2016. This means that, when used in a 50/50 blend, this would exactly meet Schiphol’s hypothetical synthetic kerosene demand in 2016. Given that this demand is set to grow, a larger supply of carbon, from other plants or the air, would be needed.

From the above we know that it is technically possible to produce sizeable quantities of synthetic kerosene, yet it is unclear whether this is also (at least somewhat) economical. This report therefore concentrated on the future techno-economics and business case of synthetic kerosene production in the North Holland area in 2030. We found that in our reference scenario A1 (based on reference projections) with Tata Steel’s waste gases as the sole carbon source, synthetic kerosene would cost 1292€/t, compared to 596€/t for fossil kerosene, giving CO₂ abatement costs of 112€/t (and a consumer flight ticket price increase of 20% - 50%, all other things being equal). In the same scenario with DAC exclusively (B1), these costs would be 1778 €/t, 596 €/t and 188 €/t CO₂, respectively. The uncertainties about the oil price and electricity price are so large and their values so critical, that a deviation in either can make synthetic kerosene cheaper than fossil kerosene or push its price to a point where it is very uneconomical.

Yet a scenario (A2) that does not deviate much or unreasonably from the reference scenario A1 shows that parity could be reached quite easily. With a moderate CO₂ price, a slightly higher oil price, an electricity price which is in line (if not conservative) with wind power projections (of 2020), and the sale of a byproduct (oxygen), synthetic kerosene would cost as much as fossil kerosene – meaning CO₂-abatement costs would be 0 €/t CO₂. If we feature in additional societal and system benefits, it would even cost less. With a business case like this and the momentum that various organisations and initiatives are gaining, it is possible that the 2020s may see a large synthetic kerosene production capacity arrive in the Netherlands, if organisations involved with this study decide to take on the role of pioneers.



NEXT PHASES

We saw that synthetic kerosene compares favourably to its alternatives and that there is reason to believe price parity between fossil and synthetic kerosene can be achieved in the year 2030. This means that there is a strong incentive to start up synthetic kerosene production. Since a plant of the size described in this report would call for huge investments, we attempt to suggest a path that would pave the way for such a plant requiring about 14 - 19 million euro investment excl. financing and 23-30 million euro investment incl. financing, which could be split between various partners. These are rough cost estimates, which are best worked out in greater detail by an experienced engineering firm.

PHASE 1: SMALL, MODULAR AND INDEPENDENT

A good first phase could be to operate the individual process steps, modularly and at a small scale. If we look at the kerosene production chain (via CO₂ electrolysis and Fischer-Tropsch), we see that several process steps can be modular: DAC, CO₂ electrolysis and water electrolysis. This means that these processes can easily be run at a small scale. CO₂ and CO capture, as well as FT synthesis and upgrading, are not modular. CO₂ and CO, however, we can choose to capture from the 'relatively' small BOFG waste stream, of which we could separate a fraction. Moreover, we can decrease the capture yield of the process. Such a pilot is also in Tata Steel's interest, as it is currently evaluating the options it has for its waste gases. One thing is rather certain: regardless of whether waste gases will be utilised or stored, they will have to be captured.

The Fischer Tropsch step is arguably the most complex step in this production chain, and one of the most capital-intensive. Fortunately, we note it is also by far the most mature technology in this list. We therefore propose to carry out all process steps independently and at a small scale, to the point we have produced syngas, which is the feedstock of the FT process. This syngas can then be analysed and sent to FT synthesis and upgrading reactors. One party in the Netherlands which develops small-scale GtL plants (which include such reactors) is HyGear, which is also involved in European synthetic fuel projects¹⁷³. It would be informative to produce several 'samples' of syngas with different carbon sources: one from Tata's waste gases exclusively, one from DAC exclusively, and one from a mixture.

Moreover, although techno-economic data were limited, it would also be recommended to investigate and perhaps on a test-scale deploy Lanzatech's alcohol-to-jet pathway, which is the most promising alternative - and potentially, depending on the conditions, more competitive.

By running the production chain in this fashion, we make an important step towards synthetic kerosene production and benefit from several advantages. First and foremost, we will discover whether synthetic kerosene production is 'possible' and what limitations might be there, for every carbon source. Second, this will not demand large CAPEX. Third, this would not only be informative for synthetic kerosene production, but for a much wider range of processes and ideas - many technologies, such as DAC and CO₂ electrolysis, have gained interest for a huge variety of applications. Lastly, investigation and deploy of Lanzatech's process should help making more informed decisions for the next phase.

INVESTMENT ESTIMATE

Investments for this phase will largely depend on the size of the units under consideration. We assume a 9 kton CO₂-eq/y facility, which is roughly 1,000 times smaller than the envisioned full-scale plant used in the business cases. Of course, it is possible to opt for a plant of a different size, which may reduce investments. We suppose that of these 9 kton CO₂-eq, 0.9 kton comes from DAC, 2.1 kton comes from CO₂ capture and the remainder from CO capture (6 kton CO₂-eq, or 3.8 kton CO). This ensures relatively low investment costs in CO₂ electrolysis and DAC.

¹⁷³ HyGear (2017): Gas-to- Liquid

Building and development costs for Climeworks' 2017 0.9kt CO₂/y plant were 3 to 4 M€¹⁷⁴. Given that they are scaling up the DAC unit production line and development costs will be significantly less, we may expect investment costs for a plant of this size to equal about 2 M€. Investment costs for CO₂ capture were 180 €/t CO₂/y, so 180 * 2.1 kt CO₂/y = 0.38 M€. At a large scale, CO investment and O&M costs result in a price of 17.8 €/t CO, so with a lifetime of 20 years and 3.8 kton capacity this would have required an investment of 17.8 €/t CO * 20 y * 3.8 kton/y = 1.35 M€. This estimate is conservative as O&M costs are included, yet also optimistic as downscaling effects have been neglected. We assume these effects cancel.

Investment costs 9 kt CO ₂ -eq plant	M€
CO ₂ capture (2.1 kt)	0.4
CO capture (6 kt CO ₂ -eq)	1.4
DAC (0.9 kt)	2
PEM CO ₂	0.6
PEM H ₂	4.7
FT	5.3
Total excl. financing	14.4
Financing (5%, 10y)	9.1
Total incl. financing	23.5

To turn our 3 kton of CO₂ into CO, we need a 1.2 MW PEM electrolyser (operating 5,000 FLH at 0.55 efficiency). With current investment costs of €800/kW, this would require an investment of 1.0 M€. With this we obtain a total of 9 kt * (28 g/mol / 44 g/mol) = 5.7 kt CO, i.e. 5.7 kt / (28 kt/Gmol) = 0.20 Gmol of CO. According to the chemical reaction for the Fischer Tropsch process, this calls for 0.20 Gmol * (23/11) * 2.016 kt/Gmol = 0.86 kt H₂. This hydrogen quantity requires, at 5,000 FLH and a 0.70 efficiency, a production capacity of 8.6 MWe. At current prices of €800/kW, this amounts to an investment of 6.9 M€. If both electrolysers (water and CO₂) operate almost continuously at baseload (8,000 FLH), the required capacity is not 1.2 + 8.6 = 9.8 MW, but 0.8 + 5.9 = 6.7 MW, requiring not 7.8 M€ but 5.3 M€. We would suggest opting for the latter capacity combined with baseload operation, as there will probably be little excess electricity in the period 2019 - 2023. It is important, however, to test how apt the PEM electrolysers are at following the volatile electricity production patterns.

With these quantities of CO and H₂, we can produce 0.20 Gmol / 11 * 156 kt/Gmol = 2.8 kton of FT products. At a density of 0.804 kg/l and 159 l/bbl, this amounts to 2.8 kton / 0.804 kg/l / 159 l/bbl = 22 kbbbl/y. This amounts to a capacity of 60 to 70 bbl per day. Investment costs for GtL plants have been between \$100k-120k / (bbl/d) for existing large scale plants e.g. Pearl (140 k bbl/d)¹⁷⁵ as well as newer plants (2.6 k bbl/d)¹⁷⁶. To account for down-scaling effects, we estimate investment costs for a 60-70 bbl/d plant to be \$ 200k / (bbl/d). A GtL plant consists of gasification step to produce syngas, followed by FT synthesis and upgrading. In synthetic kerosene production, we produce syngas directly and do not require this gasification step. We assume that gasification investment costs make up 55% of total investment costs as they do for large systems^{177 178}, meaning the investment costs for FT synthesis and upgrading are 0.45 * \$ 200k / (bbl/d) = \$ 90 k / (bbl/d). For a 70 bbl/d capacity, they equal 6.3 M\$, or 5.3 M€.

Total investment is therefore 14.4 M€, excluding a possible LanzaTech test system. If this is financed through a loan with 5% interest, depreciated in 10 years, the capital charge is 9.1 M€ and total costs incl. financing 23.5 M€. If a LanzaTech system is included and has its size matched with this train, investment costs would probably be slightly smaller than the FT reactors. This would add another 4 to 5 M€ without financing.

¹⁷⁴ Gasworld (2017): Climeworks' first commercial direct air capture (DAC) plant is now market ready

¹⁷⁵ Arno de Klerk (2012): Gas-to-liquids conversion

¹⁷⁶ Nexant (2015): Small-Scale GTL Technologies on the Brink of Commercialization.

¹⁷⁷ Oxford Energy Institute (2013): Gas to Liquids. Historical Developments and Future Prospects.

¹⁷⁸ NETL (2013): Analysis of Natural Gas-to Liquid Transportation Fuels via Fischer-Tropsch

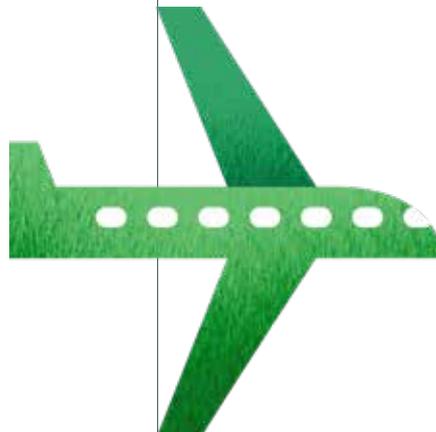
PHASE 2: INTEGRATION AND SCALING

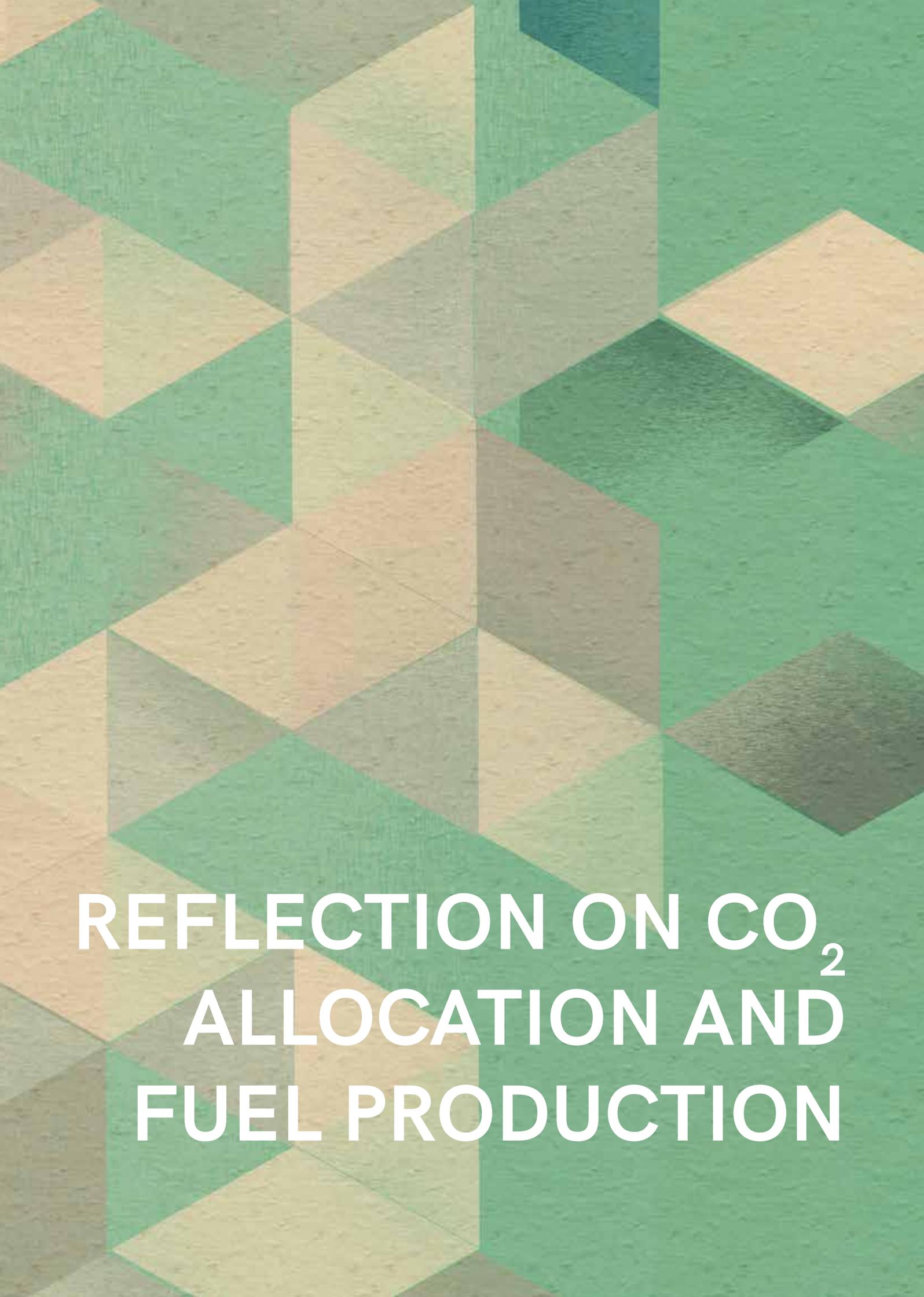
If phase 1 is successful, there are two main paths ahead. One would be to directly construct a full-scale synthetic kerosene production plant; the other would take an intermediate phase of constructing a small-scale plant before doing the same. Both come down to integrating the process and scaling it. In this phase, a decision should be made on the exact production pathway (e.g. RWGS vs CO₂ electrolysis and AtJ vs FT). It may therefore be beneficial to test other process steps in the way that is described in phase 1 beforehand, if it seems at that point that such process steps might be technically or economically favoured to the ones that had been tested initially. It is also important to at this stage investigate what other synthetic fuel infrastructure, plants and initiatives are active or under construction around the world. For instance, if there is a large hydrogen transmission system in place, it might be economical to purchase hydrogen rather than produce it on-site.

After this technology and process inventory has been made, a decision can be made on the exact plant specifications, process design and location.

GOVERNANCE

Given the novel and integrated character as well as the financial requirements of a synthetic kerosene production facility, we believe it may be best if governance is held by a consortium of 5 or 6 parties with relevant expertise and/or experience as well as the Dutch government. Since biomass usage in coal power plants will be removed from the Dutch SDE+ subsidies and the latest offshore wind parks do not require large subsidies, there may appear some room to support other activities that reduce CO₂ emissions such as synthetic kerosene production





**REFLECTION ON CO₂
ALLOCATION AND
FUEL PRODUCTION**

There are few thoughts on this topic that we would still like to share.

In this work, we are considering CO₂ emission savings for the system or society as a whole. If we were to look at the parties involved with a hypothetical kerosene plant, things might look a little different. In a scenario with DAC exclusively, there is no problem, as this is a cycle in which CO₂ extracted from the air is compensating for CO₂ emitted. In a scenario where Tata's waste gases are used, however, it is not clear-cut to which party CO₂ emissions savings are to be allocated - the steel plant or the aviation sector or both? This is a discussion that is merely administrative, but should be had. For the system or society, it does not matter.

We have limited ourselves strictly to kerosene production (although some other hydrocarbon fractions, e.g. in the diesel range, are produced as well). The motivation for this has been given earlier. Some parties are intentionally working on producing other synthetic fuels, such as gasoline and diesel. They are often driven by the belief that this results in fuels which are carbon neutral, can be used in existing vehicles and can be used in heavy-duty vehicles (HDV) which, some believe, are hard to electrify. Although it is true that synthetic gasoline and diesel (from DAC) could be carbon neutral, this may not be the preferred option.

The main reason for this is that alternatives exist which are simply vastly better. Both for low and heavy-duty vehicles, electric alternatives exist which are far more efficient, economical (over their lifetime) and do not require high-value carbon.

Electric motors are about two to three times as efficient as internal combustion engines (ICEs). Moreover, they merely require electricity - whereas a carbon neutral ICE would require far more electricity, converted into hydrogen, combined

with carbon, giving synthetic fuel. As a consequence, using electricity directly is more than two times as efficient. Combining fuel and motor efficiencies, a fully electric vehicle is four to six times as efficient as an ICE vehicle running on synthetic fuels.

Electric vehicles are generally also cheaper over their lifetime than their ICE competitors. They typically have higher investment costs but significantly lower operational costs. Until recently, this was mostly limited to low-duty vehicles. However, with the release of Tesla's Semi truck which has an 800 km range, half the operational costs of an ICE truck and 25% to 75% higher investment costs¹⁷⁹, a serious electric HDV has emerged. Given that this is a first-of-a-kind technology, we may even expect performance and costs to improve over the next years.

Lastly, electric vehicles do not require carbon to run. Carbon, whether captured from (limited) waste gases or from the air, will most probably become more valuable. Although there is plenty of carbon in the air, our ability to extract it is limited. In analogy to arable land and feedstock, it is best to use the land and carbon (feedstock) for that purpose which has the highest value. There exist several 'bio' value pyramids, but we do not know of a carbon pyramid yet - which is a topic worthy of further thought and discussion. In a hypothetical carbon pyramid, one thing is certain: carbon used for fuels for which no alternative exists (e.g. kerosene) should be higher than fuels for which alternatives do exist (e.g. gasoline).

Hence, although possible, electricity is energetically, process-technically and economically favoured to synthetic fuels and carbon best used there where it has the highest value and no substitute is available.

¹⁷⁹ Tesla (2017): *Semi*

APPENDIX A: MODELLING SYNTHETIC KEROSENE PRODUCTION IN THE ENERGY TRANSITION MODEL

Synthetic kerosene production will not stand on its own. Instead it will be able to play a significant role in the energy system, not only by providing a renewable fuel for aviation, but also by its ability to balance large variations in the supply and demand of electricity. In order to explore and quantify this role, synthetic kerosene production has been included in the Energy Transition Model.

The Energy Transition Model (ETM) is an open source, free to use, online application, that lets its users explore potential futures of the energy system. The ETM is used by governments, NGO's, consultancies and for educational purposes. The user of the ETM makes choices regarding supply and demand of energy, costs and. After each choice, the ETM instantly calculates the resulting energy system and reports the effects of the choices through a series of system parameters and charts. The ETM also performs a merit order calculation and determines which dispatchable plants need to run to meet electricity demand or, in scenarios with high volatile electricity production, if any excess electricity is available for flexibility options like power-to-power, power-to-heat, power-to-gas and power-to-liquids.

Synthetic kerosene production in the ETM consists of multiple steps. The first step is to include power-to-liquid units in the scenario. These units consist of electrolyzers that produce

hydrogen from excess electricity. This excess electricity only occurs when supply exceeds the demand of electricity, so the user has to include quite some volatile electricity production in his scenario. The model takes into account storage costs for the produced hydrogen, such that the remainder of the kerosene production, i.e the carbon capture and Fischer-Tropsch processes, can work in baseload. The user of the ETM can select the source of carbon from three options: a point source of CO or CO₂ or through direct air capture. The ETM will calculate the resulting output of synthetic kerosene and supply this to international aviation, thereby replacing the need for fossil or bio-kerosene. When synthetic kerosene exceeds the kerosene demand, then the excess kerosene will be exported. The ETM will also calculate the required investment costs and achieved reduction of CO₂ emissions. These reductions can be assigned by the user to international aviation itself or to the industries that supply the CO or CO₂ to the synthetic kerosene production. While creating a scenario, the ETM will keep the user informed about the effects of the choices he or she makes by showing relevant parameters and charts.

Renewable synthetic kerosene production is available on the Live server of the ETM (<https://pro.energytransitionmodel.com/>). The ETM can be accessed free of charge. Figure 5 shows an example of synthetic kerosene production in a scenario that focuses on reduction of CO₂ emissions by electrification and large numbers of offshore wind turbines. Everyone is invited to create his or her own scenario by accessing the ETM through one of the above hyperlinks.

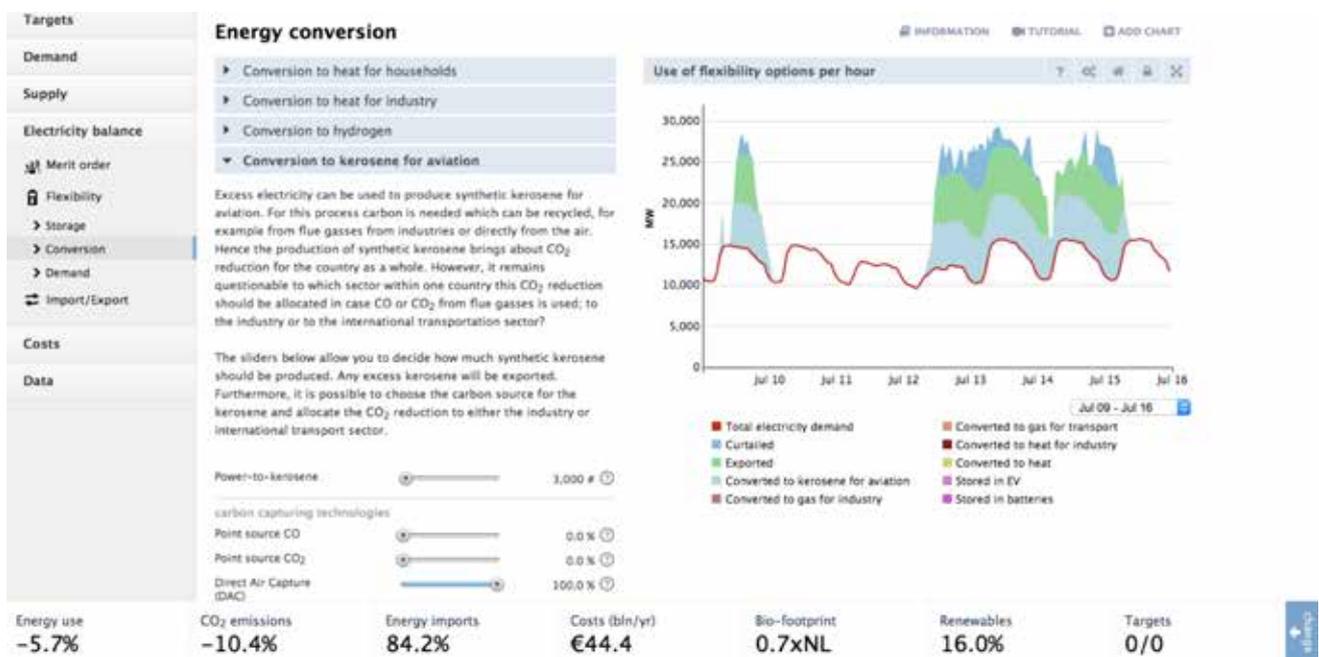


Figure 5: Synthetic kerosene production in the Energy Transition Model. In this scenario, at times when the electricity supply exceeds the demand, the excess electricity is first converted to synthetic kerosene, then exported and lastly curtailed.

APPENDIX B: STEERING AND SUPPORT GROUP

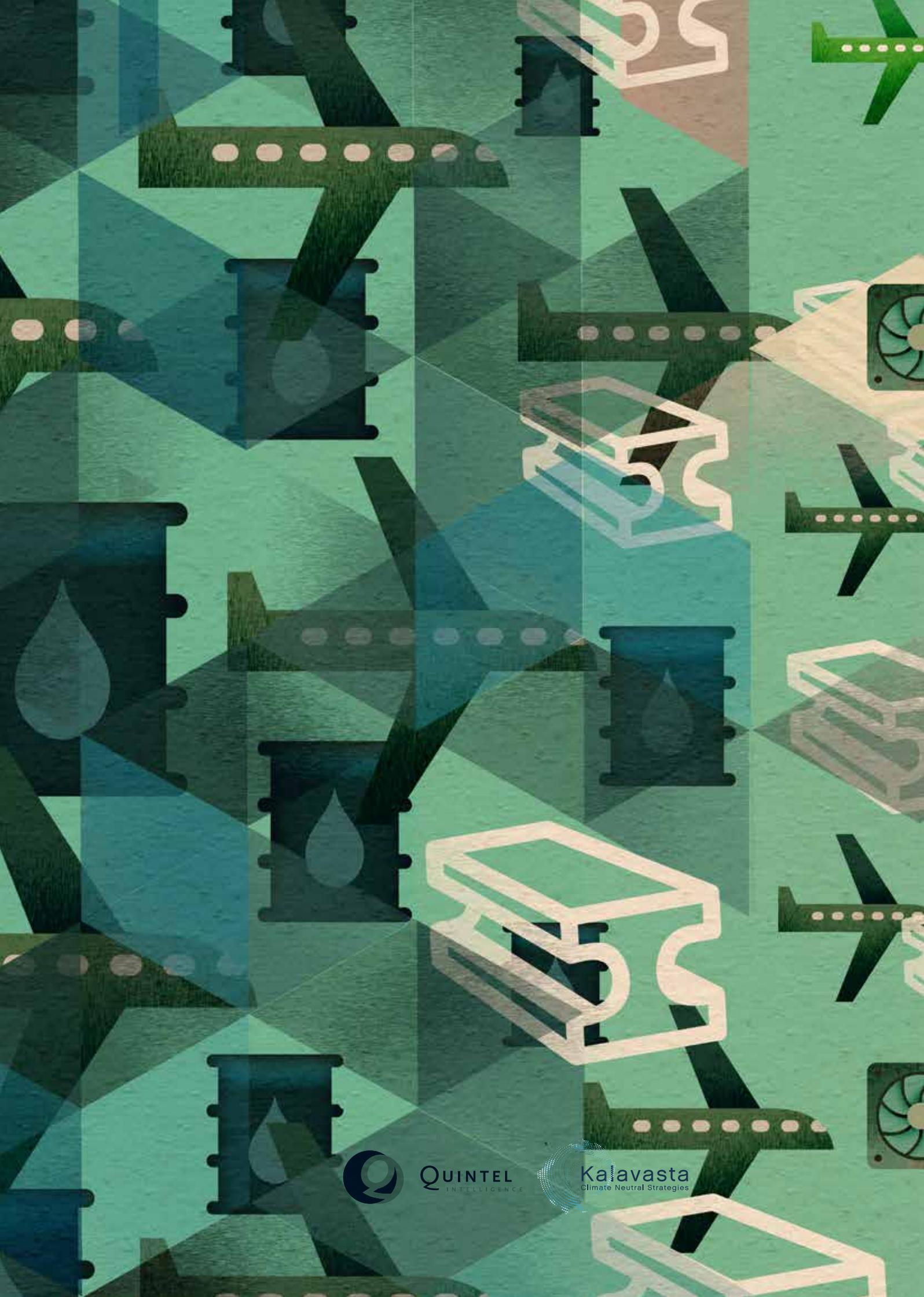
STEERING COMMITTEE MEMBERS		
NAME	POSITION	ORGANISATION
Jurriaan de Jonge	Director Fuel Supply & Risk Management	KLM
Fokko Kroesen	CSR & Environmental Strategy	KLM
Arjen Schneiders	CTO	Koole Terminals
Sanneke van der Kley	Business Development - M&A coordinator	Koole Terminals
Peter Boers	Managing Director	Oiltanking Amsterdam
Martijn Schaeffer	Commercial Manager	Oiltanking Amsterdam
Femke Brenninkmeijer	Head Energy, Cargo & Offshore	Port of Amsterdam
Floris van Foreest	Manager Corporate Development	Port of Amsterdam
Ewald Breunesse	Manager Energy Transitions	Shell
Paul Boogers	General Manager Emerging Technologies	Shell
Mark Klokkenburg	R&D New Energies	Shell
Xiao Fu	R&D New Energies	Shell
Frans Saris	Director	Stichting Sanegeest
Cock Pietersen	Manager Energy Procurement	Tata Steel
Gert van der Lee	Long Term Transmission Gridplanning	TenneT
Peter Alderliesten	Director	TKI E&I
Andreas ten Cate	Director International Business Development	TKI E&I
Jan van Schijndel	Consultant to	TKI E&I
Gert Jan Kramer	Professor	Utrecht University

WITH THE COOPERATION OF

NAME	POSITION	ORGANISATION
Geoff Holmes	Director of Business Development	Carbon Engineering
John Bruce	Corporate Development	Carbon Engineering
Daniel Egger	Department Head, Marketing & Sales	Climeworks
Jaap Vente	Innovation Manager	ECN
Lucas Bertrand	Business Development Director France - Benelux	ITM Power
Madadh Maclaine	Innovation Manager	ITM Power
Rob Duivis	Fleet Manager GE90/CFM56-7B	KLM
Nicholas Flanders	CEO	Opus 12
Alina Chanaewa	Head of R&D	Skytree







QUINTEL
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