REVIEW OF TECHNOLOGY DATA FOR ADVANCED BIOENERGY FUELS

Prepared For:

Danish Energy Agency
Amaliegade 44,
1256 København K
Denmark

Prepared By

(S&T)² Consultants Inc.
11657 Summit Crescent
Delta, BC
Canada, V4E 2Z2

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EXECUTIVE SUMMARY

The Danish Energy Agency is developing an LCA model for transportation fuels. They engaged Force Technologies to produce verified performance and financial data for the production of advanced biomass fuels.

Force Technology developed data for a total of 17 technologies such as production of first gene-ration bioethanol, biodiesel from rape seed oil or synthetic natural gas produced though gasification of solid biomass.

Force developed technology data sheet with a short technology description, a Sankey diagram illustrating the fundamental energy balance, and a table with information on capacity, investments, efficiencies, operational costs etc.

This report reviews the information developed by Force with a focus on whether the data used represents the best available information. We do note that there is a range of commercial status of the seventeen pathways and that makes the direct comparison of the pathways difficult as the quality of the data will vary between the pathways. We also noted that the system boundaries are not the same for all of the technologies. The different system boundaries are not necessarily an issue, but care must be taken in how the information in the Force report is used. It is just that using the Force report to make direct comparisons between the technologies is a challenge.

For each of the pathways we have provided comments on the process description and the status of the technology, the proposed energy balance information, the capital costs, and the operating costs. A constant format is used for each of the technologies.

There are many challenges when this type of analysis is undertaken. First, the systems that are compared are at various stages of development, some are commercial, and some are at early stages of development with any number of possibilities in between those extremes. This makes it very difficult to normalize the data.

Second, the information that is available for the different systems may not be consistent. One can make attempts to provide consistency by scaling data so that plant sizes are comparable or applying inflation factors so that costs are presented for the same year, or trying to adjust the data so that it is all representation of a fully commercial and mature system but in many cases the detail information on the systems may be silent about critical aspects, for example is working capital included in the capital cost estimates or not?

Third, it is just not possible to verify some of the data that project developers present. Have they actually achieved the performance that they suggest or are they presenting information based on what they expect to achieve with additional development?

Force has assembled a dataset for seventeen technologies and delivered a consistent set of metrics for each of the technologies. It is apparent that in a number of cases estimates have had to have been made as the data is not yet available; this is particularly true of O&M costs where a percentage of the capital cost is used in many cases. We think that in many cases these estimates are too low.

Another challenge that Force faced was how to deal with systems that produce more than one product or have co-products. How these are dealt with will influence the reported metrics and ultimately the economics of the processes. In most cases, the co-products have been excluded from the metric and the analysis but the comparison of the Inbicon and the Maabjerg systems shows how important the treatment of co-products to the technical and economic metrics is to the results. Maabjerg converts the Inbicon co-products to energy and thus includes them in the energy and economic metrics and they are largely excluded in the Inbicon system because they are co-products.

The following table has been prepared to summarize the primary findings of the Force report. For each of the technologies, the plant size, two different approaches to plant efficiency, the capital cost, and the O&M costs are presented.

Table ES- 1 Technology Summary

Technology	GJ/Year	Process Energy Efficiency, Fuel	Total Process Energy Efficiency, Fuel + Coprods	Capital Cost Euro/GJ	O&M, Euro/GJ	O&M, % Cap Cost
Bio-Methanol	5,970,000	52.9%	52.9%	35.1	1.1	3.1%
Methanol from CO_2 and Electricity	796,000	53.5%	53.5%	44.9	1.35	3.0%
1st Gen Bio-Ethanol	5,360,000	45.5%	76.5%	18.6	2.05	11.0%
2nd Gen Bio-Ethanol	5,360,000	41.1%	44.1%	69	5.3	7.7%
1st Gen Biodiesel by transesterification	7,460,000	91.0%	95.6%	4.4	0.13	3.0%
1st Gen HVO Diesel	35,200,000	88.6%	90.8%	19.4	0.58	3.0%
2nd Gen Biodiesel	4,620,000	39.9%	59.1%	112.9	3.4	3.0%
Diesel from Methanol	5,280,000	77.5%	91.1%	21.9	0.66	3.0%
Bio-DME	6,248,000	53.2%	53.2%	43.7	1.3	3.0%
BioSNG	2,970,000	56.3%	56.3%	118	3.5	3.0%
2nd Gen Bio-Kerosene	4,620,000	39.3%	59.1%	113.9	3.4	3.0%
Torrefied Wood Pellets	2,170,000	92.8%	92.8%	10.4	0.73	7.0%
Bio-liquid	229,813	25.6%	76.0%	116.8	5.84	5.0%
2nd Gen Bio-Ethanol Inbicon	1,554,400	85.6%	95.7%	164.7	23.1	14.0%
Maabjerg Energy Concept	3,650,000	67.0%	99.0%	119.4	12.1	10.1%
2nd Gen BioDiesel w/ Hydrogen Addition	6,587,000	41.3%	61.1%	84	2.5	3.0%
SNG by methanation of biogas	179,500	80.3%	80.3%	24.4	0.49	2.0%

System Boundaries

The described systems do not all have the same system boundaries. The best example is the comparison of the last two technologies. With the second gen biodiesel with hydrogen production, the hydrogen is an input (produced outside of the system boundary) and with the SNG from biogas, the hydrogen required for the system is produced inside the system boundary. The different treatment impacts the efficiencies, the plant capital costs and the O&M costs.

Plant Size

There is factor of 20 between the largest plant and the smallest plant in terms of energy output. While there are technical factors for this, care must be taken when any comparison of the process metrics are undertaken.

Process Efficiency

Up to three different metrics are presented for process efficiencies depending on the technology.

> ***Without Co-products***
> The process efficiency without co-products is the least useful metric. Many of the technologies produce significant co-products and excluding them from the analysis presents an unbalanced view of the process.
>
> ***With Co-products***
> Including any co-products produced the best means of comparison between the technologies assuming that the system boundaries are comparable.
>
> ***With District Heat***
> Including the potential energy recovery for district heating will tend to narrow the differences between the technologies. While this may be appropriate for Denmark, other jurisdictions may not have the same opportunities and that could influence the rate at which the technology is employed and rate at which the learning experiences are gathered.

Capital Cost

The capital cost estimates came from a number of different sources and are presented on different basis. Many were derived from NREL reports and are representative of the n^{th} plant. Others represent the first plant and are therefore higher cost that the n^{th} plant. An attempt should be made to present the capital costs on the same basis.

The different system boundaries will also impact the capital cost estimates but moving the costs in or out of the system boundary.

O&M Costs

The O&M cost presentation appears to be quite variable and probably the values with the lowest level of confidence in the reports. This is not unexpected since many of the technologies are not yet in production.

> ***Actual Values***
> In the cases of the commercial technologies, the O&M costs estimated by Force are lower than information that we have on these systems.
>
> ***Percentage of Capital Costs***
> While the percentage of capital cost basis is often found in work of this kind we think that the estimates provided by Force are too low.

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1. INTRODUCTION

The Danish Energy Agency is developing an LCA model for transportation fuels. They engaged Force Technologies to produce verified performance and financial data for the production of advanced biomass fuels.

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This report reviews the information developed by Force with a focus on whether the data used represents the best available information.

1.1 PATHWAYS

The pathways are presented in this review in the same order that they are presented in the Force report. We do note that there is a range of commercial status of the seventeen pathways and that makes the direct comparison of the pathways difficult as the quality of the data will vary between the pathways. We also noted that the system boundaries are not the same for all of the technologies. The different system boundaries are not necessarily an issue, but care must be taken in how the information in the Force report is used. It is just that using the Force report to make direct comparisons between the technologies is a challenge.

For each of the pathways we have provided comments on the process description and the status of the technology, the proposed energy balance information, the capital costs, and the operating costs. A constant format is used for each of the technologies.

1.2 ECONOMIES OF SCALE

Force has used an economy of scale factor of 0.7. This is used to adjust the capital costs in the literature to the scale of the technology chosen for Denmark. The same factor is used for all technologies although not all of the technologies required scaling of the data.

In the literature one can find a range for this factor from 0.25 to over 1.0 (Moore, 1959). The 0.6 rule has been used by engineers since at least the 1950's and it has been known that while it works well for individual pieces of equipment it may not necessarily apply to complete plants.

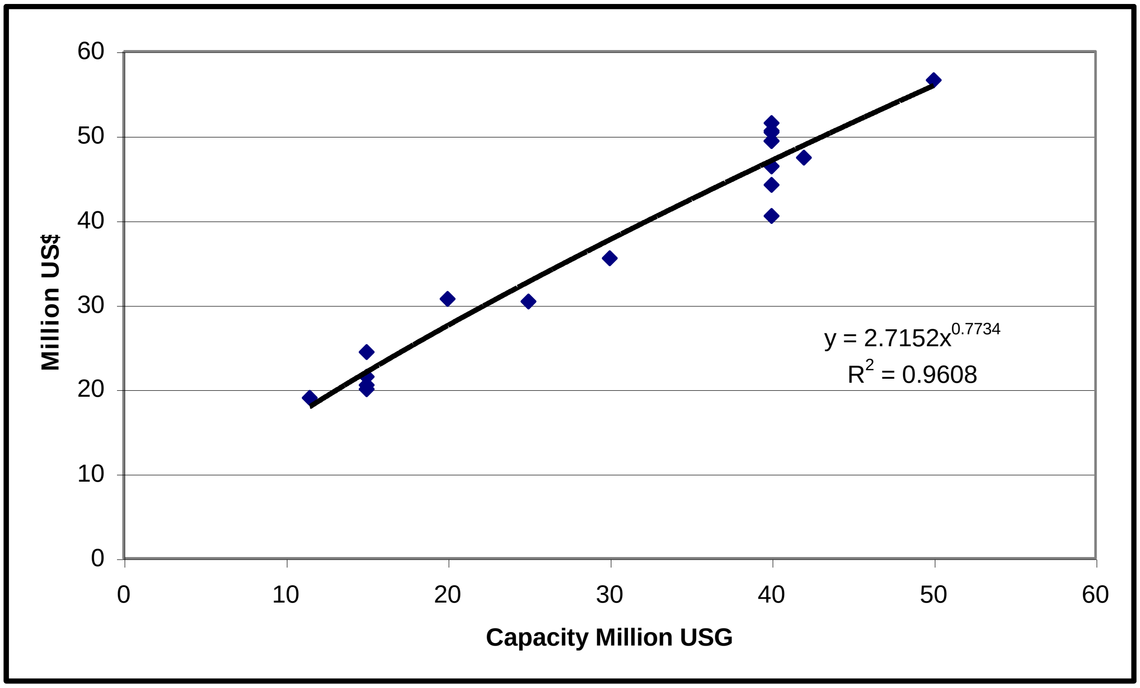
$(S\&T)^2$ (2004) analyzed the capital cost data for a number of US ethanol plants built between 1996 and 2004. In the following table, the capital costs of a number of plants are summarized. All of these plants are dry mill operations. Most of these plants have been able to exceed their nameplate production capacity in continuous operation but only the nameplate data is used in the table. The early data is from company press information and the more recent data is from the company SEC Filings. In some cases, the plants were not built due to problems raising the financing but fixed price agreements for plant construction were entered into so that data has been used. Project costs include total working capital requirements some of which is financed by the accounts payable, to equalize the data the working capital ratio has been assumed to 1.0 for operating plants with higher ratios.

Table 1-1 Capital Costs of Recent US Corn Ethanol Plants

Name	Location	Year	Design Size Million USG/yr	Capital Cost Million USD	$/USG	Project Cost Million USD	$/USG
Chippewa Valley Ethanol	Benson, MN	1996	15	24.4	1.62	31.3	1.70
Agri-Energy LLC	Luverne. MN.	1998	15	20.5	1.37		
Exol	Albert Lea, MN	1999	15	20.0	1.33		
Ethanol 2000	Bingham Lake, MN.	1997	11.5	19.0	1.65		
Golden Triangle	St. Joseph, MO.	2001	15	21.5	1.43		
Dakota Ethanol	Wentworth SD.	2001	40	40.5	1.01	49.0	1.22
Badger State Ethanol	Monroe, Wisconsin	2002	40	46.4	1.16	53.1	1.33
Great Plains Ethanol	Chancellor, SD	2003	42	47.4	1.13	59.6	1.42
Golden Grain Ethanol	Mason City Iowa	2004	40	50.6	1.27	59.6	1.49
Husker Ag	Plainview, NE	2003	20	30.7	1.53	38.0	1.90
East Kansas Ethanol	Garnett, KS	2004	25	30.4	1.22	37.0	1.48
Granite Falls Ethanol	Granite Falls, MN	2004	40	46.4	1.16	54.8	1.37
Illinois River Energy	Rochelle, IL	2004	50	56.6	1.13	67.5	1.35
Iroquois Bioenergy	Rensselaer, IN	2004	40	49.4	1.23	60.1	1.50
Little Sioux Corn Processors	Marcus, IA	2003	40	50.4	1.26	56.0	1.40
Northern Lights	Milbank, SD	2002	40	44.2	1.10	54.4	1.36
Oregon Trail Ethanol	Davenport, NE	2003	40	49.4	1.23	62.5	1.56
United Wisconsin Grain Processors	Freisland, WI	2004	40	51.5	1.29	59.8	1.49
Western Plains Energy	Campus, KS	2004	30	35.5	1.18	39.4	1.31

The curve fit to the above data as shown in the following figure suggests that the overall plant exponential co-efficient is 0.77. The data points for the smaller plants are older but essentially the same curve results from only using the post 2001 data.

Figure 1-1 Impact of Plant Size on Capital Costs



Source: (S&T)[2]

A report published by the US National Renewable Energy Laboratory (NREL, 2000) used an exponential scaling factor of 0.60 to adjust the equipment costs between different plant sizes.

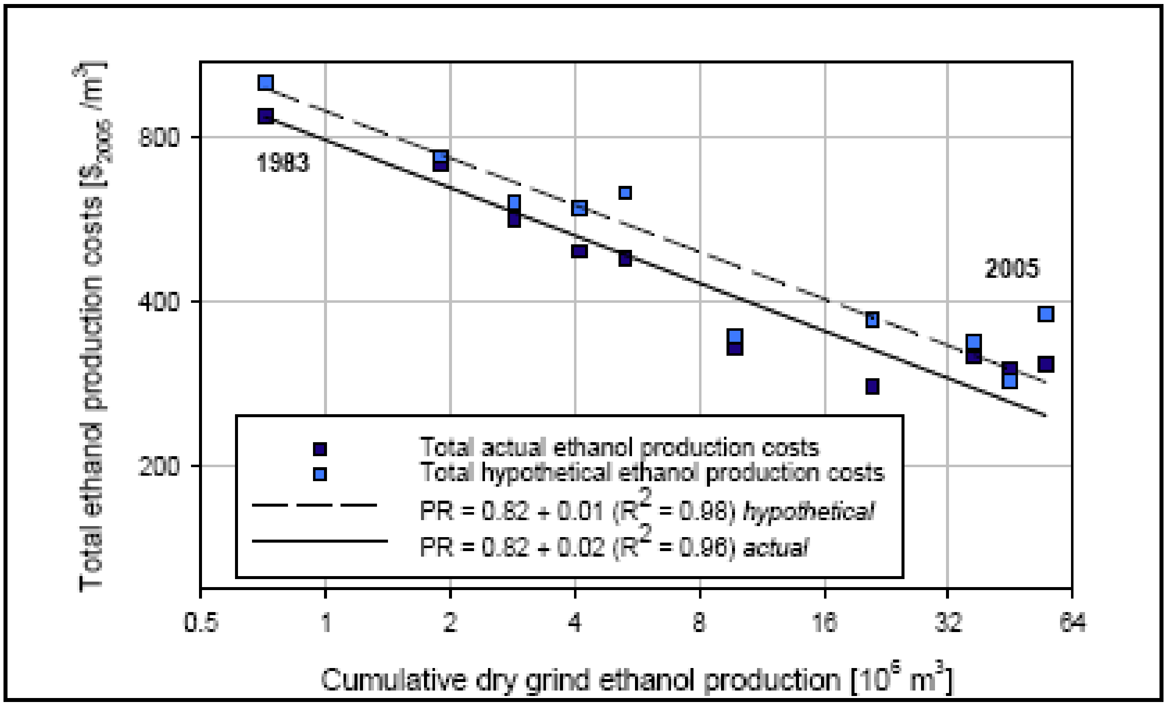
The 0.7 factor used by Force may result in the capital costs of some technologies being too low and other technologies being too high. Biochemical technologies, where multiple fermenters will be required may have capital costs that are too low, as these processes will likely have scaling factors greater than 0.7. On the other hand some thermochemical processes may better fit the classic 0.6 factor and have capital costs that are lower than estimated by Force. Comments are made with respect to this issue for each of the seventeen technologies in the following sections.

1.3 Experience Curves

Force has recommended a progress ratio of 0.95 for capital and operating costs and no factor be applied to the basic performance data of the process. The progress ratio is applied to the current capital cost and the scaling factor for plant size. Since empirically derived progress factors usually include some benefit from economies of scale using the Force methodology a higher progress ratio is appropriate. However it is not clear from the report how many of the technologies, if any, have had this factor applied to them as the columns in the data tables only have data for 2015 and the other future columns just have the note to see the sections on scaling and learning.

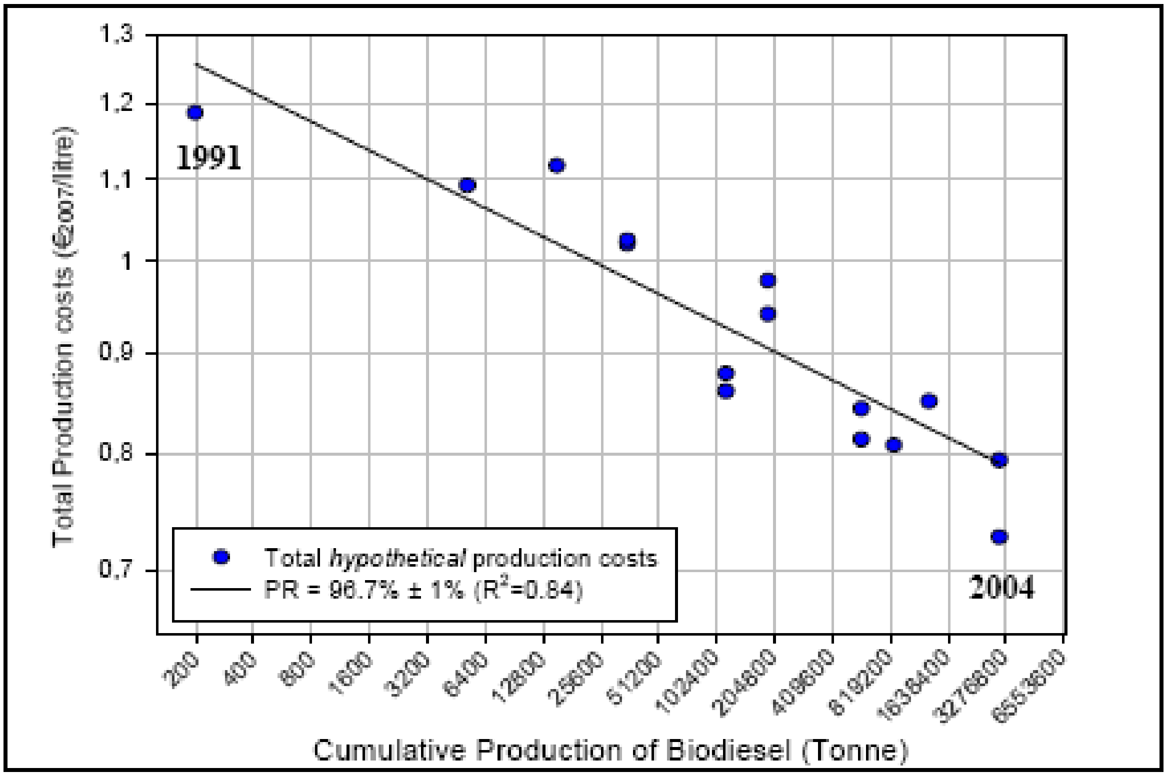
There have been two comprehensive studies on the learning curve issue with respect to first generation biofuel technologies. An excellent discussion of the application of the learning experience to the US Ethanol industry has been documented by Hettinga (2007). This source of information focussed on costs and energy use and the data can be supplemented with other data sources to develop a picture on not only what the current inputs are for the corn ethanol process but also how they developed to this point. The ethanol total production cost experience curve is shown in the following figure. This includes capital costs and operating costs. The progress ratio is 0.82.

Figure 1-2 Ethanol Experience Curve



Berghout (2008) studied the German biodiesel industry from a learning curve perspective. The progress ratio is shown in the following figure. It is quite high (0.967) probably due to the very low production in year one of the study which resulted in a large number of doublings of the production volume. This highlights one of the challenges of using experience curves to predict future performance, it is very dependent on the increase in production volume, and the doublings can be influence by low production in the first years.

Figure 1-3 Biodiesel Experience Curve



Given the uncertainty surrounding both the scaling factor and the progress ratio it might be important to run some sensitivity analyses on the factors for each of the technologies.

2. METHANOL PRODUCTION BY BTL TECHNOLOGY

2.1 PROCESS DESCRIPTION

The process considered here is biomass gasification followed by methanol synthesis. We are not aware of any plants in commercial operation that uses the concept covered in this pathway. The closest commercial operation was the Schwarze Pumpe facility outside of Dresden Germany. This facility gasified lignite, municipal solid waste, and some biomass and a portion of the gas was used to produce about 100,000 tonnes/year of methanol. The plant has had a number of owners over the past several decades. It is not currently operating.

This pathway is included in GHGenius although the data in the model dates to the 1990's. There has been little commercial interest in this pathway in North America. This lack of interest is partly driven by some opposition to the use of methanol as a gasoline blending component as well as neat fuels such as M85. MTBE, which could use renewable methanol as one of the feedstocks has been effectively banned in North America since 2005. Interest in renewable methanol on the part of the methanol producers has been variable over the past two decades.

2.2 ENERGY BALANCE

The reported process energy efficiency (methanol) of 52.9% is higher than reported in the NREL reference of 45.8% LHV. Since the feedstock requirements are similar in the Force report and the NREL report, the difference must be in the assumption of the energy content of the feedstock. The energy efficiency used in the GHGenius model is 47.6% (HHV).

A plant that will process MSW is scheduled to begin operation in 2014 in Edmonton, Canada. Process data will be available from that facility should be available in about one year. Until that data is available the NREL estimates represent the best available data.

There are no other products or co-products in this design.

2.3 CAPITAL COSTS

The NREL reference has the same sized plant as Force assumed and the capital cost was slightly lower, although that could be due to foreign exchange fluctuations. No scaling of the capital costs due to plant size was required and the NREL economics always assume the n^{th} plant for the development of the economics. The NREL n^{th} plants typically cost 43% of the pioneer plant (NREL, 2010).

NREL capital costs are generally well done. The process of estimating the capital costs has been developed over a decade or more of experience and has involved both NREL staff and commercial engineering and construction firms. They are based on a detailed equipment estimate and then factors applied for installation, direct costs (land and site development), construction indirects, and working capital. They assume that the plant is built in the United States.

2.4 OPERATING COSTS

The NREL presentation used as the reference did not include any estimates of the operating costs. NREL did do a detailed analysis of a thermochemical wood to ethanol process (NREL, 2011), which was also covered in the NREL presentation that was used as a reference for the Force study. The annual O&M costs from the Force report are 6.5 million Euros/year ($9.2 million US). The NREL report (for a more complex process with about twice the capital cost) has O&M costs of 21.8 million euros ($30.5 million US). In the NREL report, maintenance costs alone are 3% of the capital investment. The Force estimate of O&M costs of 3% of investment is therefore too low. They should probably be on the order of 5 to 6% of the capital costs.

3. METHANOL PRODUCTION BY ETL TECHNOLOGY

3.1 PROCESS DESCRIPTION

This pathway is modelled on the George Olah Renewable Methanol Plant in Iceland. Electrolytic hydrogen is combined with CO_2 to produce methanol in a standard methanol synthesis plant. The electricity can be produced from renewable sources and the CO_2 can be captured from power plants, oil refineries, or industrial processes. Depending on the source of CO_2 there will be some additional energy required to concentrate and purify the gas before it is reacted with the methanol.

Operating data from the Iceland plant has not been publicly released and thus the data table has been developed from a news release and some information on hydrogen production.

3.2 ENERGY BALANCE

The energy balance is calculated from the electric power required to produce the hydrogen plus 2% for other activities requiring power. This yields a reported efficiency of 53.3%.

The notes identify the quantity of hydrogen required for the process and the power requirements for hydrogen production are taken from an NREL report. An allowance of an additional 2% of electricity is provided for all other power requirements for the process. This seems too low considering that pressures of up to 70 bars are required for the methanol synthesis reaction unless some of the excess heat from the methanol synthesis is used to produce electricity.

The power requirement of 53.5 kWh/kg of hydrogen from the NREL report was the low end of the range provided; the high end of the range was 70.1 kWh/kg of hydrogen. The systems that used more power also provided the hydrogen at higher pressures.

The German website Hyweb reports operating efficiencies lie in the 50-60% range for the smaller electrolysers and around 65-70% for the larger plants. 53.5 kWh/kg is equivalent to 62.5% on a LHV basis.

CO_2 capture from flue gases is energy intensive, depending on the process used and the source from 2 to 4 GJ of energy are required for every tonne of CO_2 captured. This means that an additional 0.14 to 0.28 GJ of energy are required for every GJ of methanol produced. On the other hand the methanol synthesis process is highly exothermic meaning than heat is released as the methanol is produced. Some of this may be useful in capturing the CO_2 for the process or it could be used to produce electricity to supply the methanol plant needs.

The conclusion is that the proposed energy balance is an over simplification of the process. It uses a very efficient electrolyzer and it doesn’t account for energy required to capture and purify the CO_2. In practice it is likely that the energy balance will not be as good as shown in the data table.

3.3 CAPITAL COSTS

The plant modelled is an order of magnitude larger than the operating demonstration plant in Iceland but also almost an order of magnitude smaller than the biomass to methanol plant modelled in the previous pathway. The source cited in the references states that the Iceland plant cost $8 million to build.

Electrolyzers don't scale well and the company plans to build larger plants from modules similar to what has been built. This means that the economies of scale will be less than what might be available from a fully scalable technology. On the other hand, the methanol synthesis portion of the plant will scale well. However, on combination the 0.7 scaling factor is probably too optimistic for this technology.

The 4,000 tpy Iceland plant cost $2,000/tonne. Using a scaling factor of 0.7 that would suggest that the 40,000 tpy plant would cost $1,000/tonne. The capital cost shown in the data table is $640/tonne. This suggests that significant learning has been applied to the technology.

We think that a scaling factor of 0.8 is more appropriate for this type of modular production system. A factor of 0.8 will produce a cost of $1,260/tonne. This would be more in line with fermentation ethanol plants were multiple fermenters must be used to achieve the desired scale. With respect to the learning, both electrolysis and methanol production are well established production process which means the rate of learning will be much lower.

3.4 OPERATING COSTS

The estimate of O&M costs of 3% of the capital costs is used. This is likely too low and a value of 5 to 6% should be used, similar to the previous pathway.

4. ETHANOL PRODUCTION BY 1ST GENERATION FERMENTATION TECHNOLOGY

4.1 PROCESS DESCRIPTION

The data is for a corn ethanol plant and the report correctly acknowledges that adjustments have to be made for other feedstocks due to different starch contents. The impacts can be larger than just the raw material consumption. The example given is that 7% more wheat would be required due to lower starch, but this means that about 15% more DDG is produced which will require additional drying energy and the energy efficiency may not be as high due to differences in viscosity and other properties that are dependent on the feedstock.

The plant size is 200,000 tonnes/year (250 million litres/year) which is a reasonably size for an ethanol plant. A 400 million litre/year plant became a common size for a corn ethanol plant in the US during the later stages of the industry build out there.

The recovery of energy for process heat is not a common practice in North American corn ethanol plants but there is certainly some heat that is discharged through the cooling towers and the DG dryers.

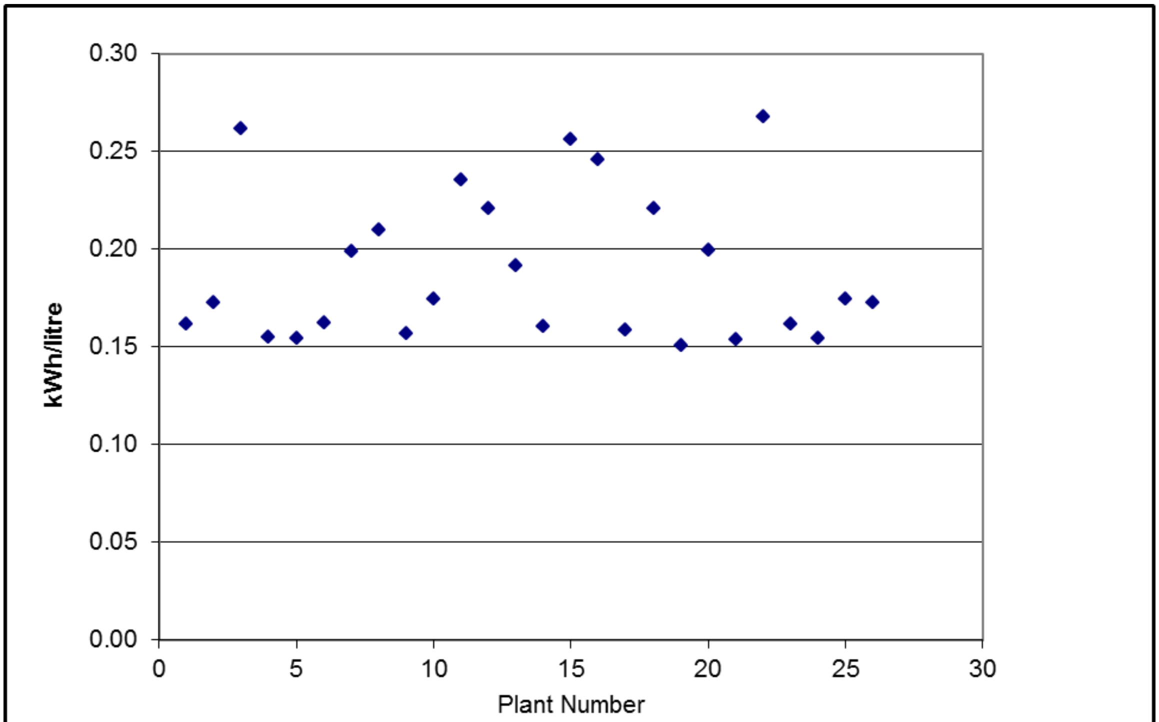
The ethanol yield (410 l/tonne) is representative of industry performance.

In spite of this technology being employed at 100s of plants throughout the world, few real world sources are listed as references for the technology.

4.2 ENERGY BALANCE

The electricity input is reported as 0.031 GJ/GJ ethanol (0.18 kWh/litre) and this is a typical value for an ICM plant. Other process developers tend to have higher power requirements. In the following figure we show the electric power requirements for 30 different ethanol plants that sell product in Canada ((S&T)^2 private data). The mean value is 0.189 kWh and the standard deviation is 0.038 kWh/litre.

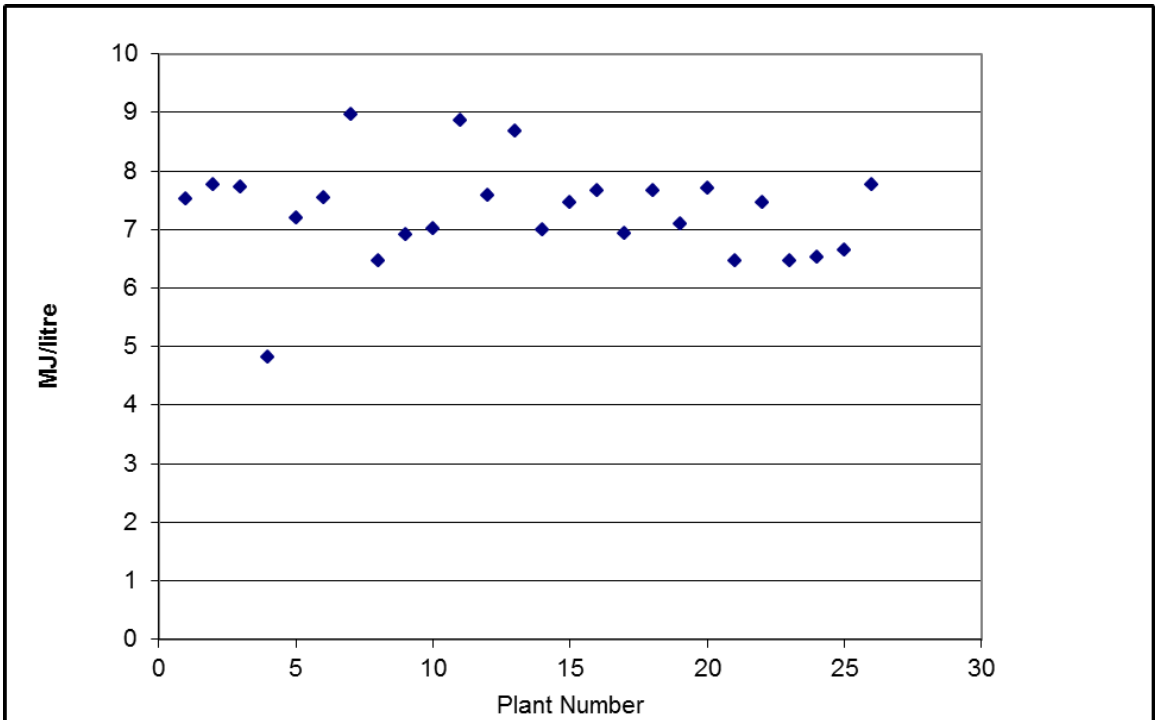
Figure 4-1 Electric Power Requirements Corn Ethanol Plants



Source: (S&T)[2]

The thermal energy input is reported as 0.43 GJ/GJ ethanol. This is 9 MJ/litre of ethanol, but it is not clear if this is the fuel energy or the steam energy, we assume that it is the fuel energy. The average value from the same plants that the power was shown for was 7.17 MJ/L (LHV) with a standard deviation of 0.84 MJ/L, assuming the fuel is natural gas. The distribution of the individual plant values is shown in the following figure.

Figure 4-2 Natural Gas Requirements Corn Ethanol Plants



Source: (S&T)[2]

4.3 Capital Costs

The reported capital costs are 0.39 €/litre ($0.53 US/litre). Plant costs are highly site dependent. There were certainly US plants that were built at approximately this cost but these would have been built with non-union but highly experienced labour. One company built about half of the US ethanol plants and greatly benefitted from the experience gained with so many plants constructed. The capital costs are aligned with those used by the Agricultural Marketing Resource Center (AgMRC) (http://www.agmrc.org/renewable_energy/), a center that is operated by Iowa State University with funding from the USDA. They currently use $0.56/litre of nameplate capacity.

4.4 Operating Costs

The reported operating costs are 0.043 €/litre ($0.06 US/litre). This is supposed to cover all non-feedstock and non-energy inputs. Information on US plant operating costs is updated monthly by AgMRC (2014). They currently estimate that fixed and variable operating costs are $0.11/litre.

There is no indication that DG revenue is included in the financial information. In 2012 and 2013 this revenue source contributed 25% of the total plant revenue and was double the fixed and variable operating costs.

The lack of information on co-product revenue is found in all of the technologies that produce multiple products. This information will be required to do proper economic modelling of the technologies.

5. ETHANOL PRODUCTION BY 2ND GENERATION FERMENTATION TECHNOLOGY

5.1 PROCESS DESCRIPTION

This data sheet is based on the conversion of lignocellulosic feedstocks to ethanol through fermentation. The process converts both the C5 and C6 sugars and the process data is based on a 2011 NREL report (reference 2). This NREL report has also been used by $(S\&T)^2$ for the basis for GHGenius inputs and it has been used by $(S\&T)^2$ for modelling work undertaken for IEA Bioenergy Task 39 (2013).

While the NREL report is the most detailed and public source of information available on this process, NREL have continued to develop the technology and some of the information is now outdated. One of the areas of development has been the waste water treatment portion of the plant as the work for the IEA highlighted the GHG intensity of this portion of the process.

Several plants that employ similar technology have either recently started production or are expected to start production this year. Operating data might be available in the public domain within the next 24 months.

5.2 ENERGY BALANCE

The energy balance has been developed by not considering the energy input from the supporting chemicals as they were assumed to be minor amounts.

The chemical amounts are not that minor, 0.376 kg of chemicals are required for every litre (0.79 kg) of ethanol produced. Most of these chemicals were input into the GHGenius model so that the energy and emissions embedded in them could be included in the results. The contribution of the individual chemicals to the total emissions is shown in the following table.

Table 5-1 Chemicals Included in NREL Process

Input	Kg/litre ethanol	MJ/kg chemical	MJ chemicals/ MJ Ethanol	g CO_2eq/kg	g CO_2eq/GJ ethanol
Glucose	0.088	29.0	0.11	2,578	9,621
Caustic soda	0.082	14.0	0.05	1,847	6,423
Sulphuric acid	0.072	2.4	0.01	211	644
Ammonia	0.043	41.7	0.08	2,734	4,986
Lime	0.033	1.8	0.00	918	1,285
Diammonium phosphate	0.005	6.6	0.00	633	134
Yeast	0.004	6.3	0.00	1,156	196
Total			0.25		23,289

The glucose has the largest impact on the emissions, followed by the caustic soda and the ammonia. The caustic is used in the wastewater treatment area. The glucose is used for enzyme production, and the ammonia is used in pretreatment and enzyme production.

The chemicals used in the production process have a significant impact on the overall lifecycle energy balance and the GHG emissions. The chemicals consume a large quantity of electric power, about 60% the power produced as a co-product, and have significant amounts of GHG emissions embedded in them. The overall performance is particularly sensitive to the quantity of caustic used in the wastewater treatment section of the plant. This may be a process area that requires increased research and development.

The chemicals should be included in the Sankey diagram as they are a significant portion of this process.

5.3 Capital Costs

A number of references have been cited in the Force report for the capital cost of the process. The total plant cost forecast by Force is $520 million US. The NREL cost estimate was $422 million US, about 20% lower. It is always preferable to use a consistent data set for these kinds of techno-economic modelling exercises. Obviously some of the other references have higher capital costs than the NREL study but is this because they are looking a slightly different designs?, have they made other trade-offs between operating parameters and capital costs that aren't reflected in the technical data?

5.4 Operating Costs

The NREL operating costs appear to have been used for the analysis. Note that these amount to 7.7% of the Force capital costs and 9.2% of the NREL capital costs, values much higher than the 3% assumed for some of the other technologies. The higher O&M costs are partially a function of the high chemicals usage in the process.

There will be additional revenue from the sale of electricity that has not been captured in the economic data but is included in the technical data. The issue of co-product credits not being captured in the economic data is common to many of the seventeen pathways.

6. BIO-DIESEL PRODUCTION BY TRANSESTERIFICATION OF VEGETABLE OIL

6.1 PROCESS DESCRIPTION

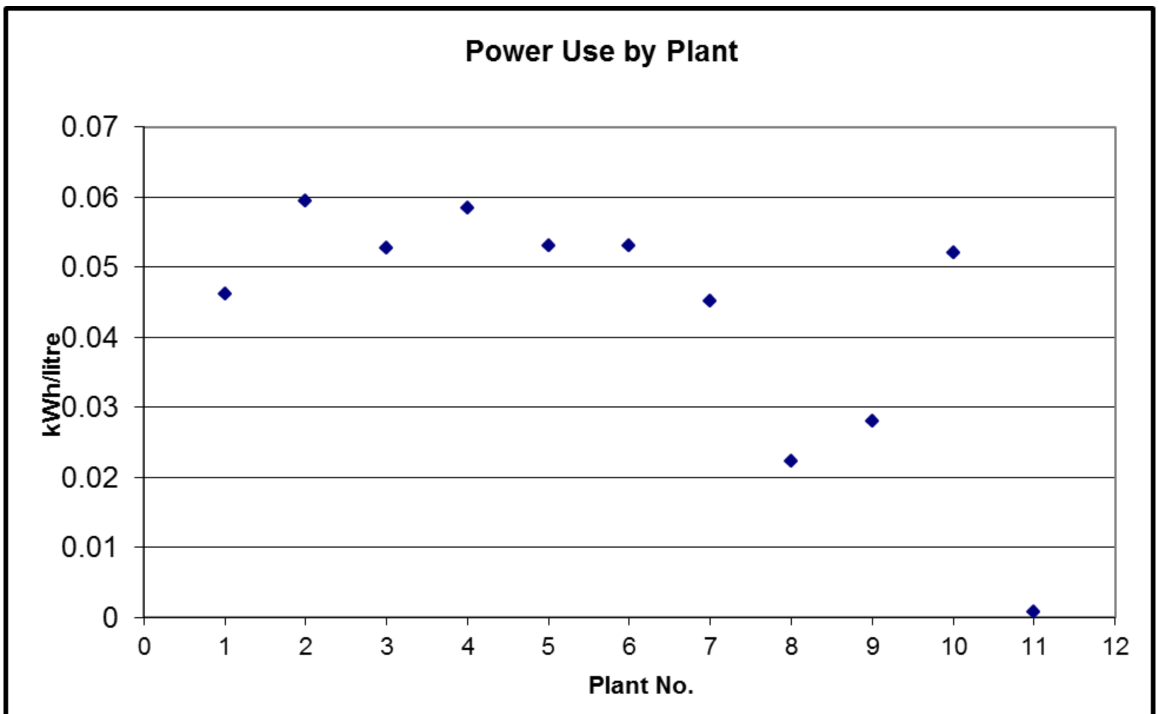
This pathway is modelling methyl ester production from rapeseed oil through the conventional transesterification process. There are many operating plants employing this technology around the world. The energy balance data does not include the production of the rapeseed or the crushing of the seed to produce the oil and the meal. The only reference is a paper on the small scale production of biodiesel yet the technical data is for a large 200,000 tpy plant.

6.2 ENERGY BALANCE

The energy balance includes the feedstock, methanol, heat and power. The products include the biodiesel and the glycerine. The heat and power requirements will be a function of the quality of the glycerine that is produced, but that information is not provided.

The process yield and the methanol requirements are consistent with current operating practices in the industry. (S&T)[2] has operating data from a number of vegetable oil biodiesel plants in North America. The data sheet uses 0.055 kWh of power per litre of biodiesel. In our experience this is only a little bit high. Data from eleven plants averaged 0.042 kWh/litre. The information is shown in the following figure.

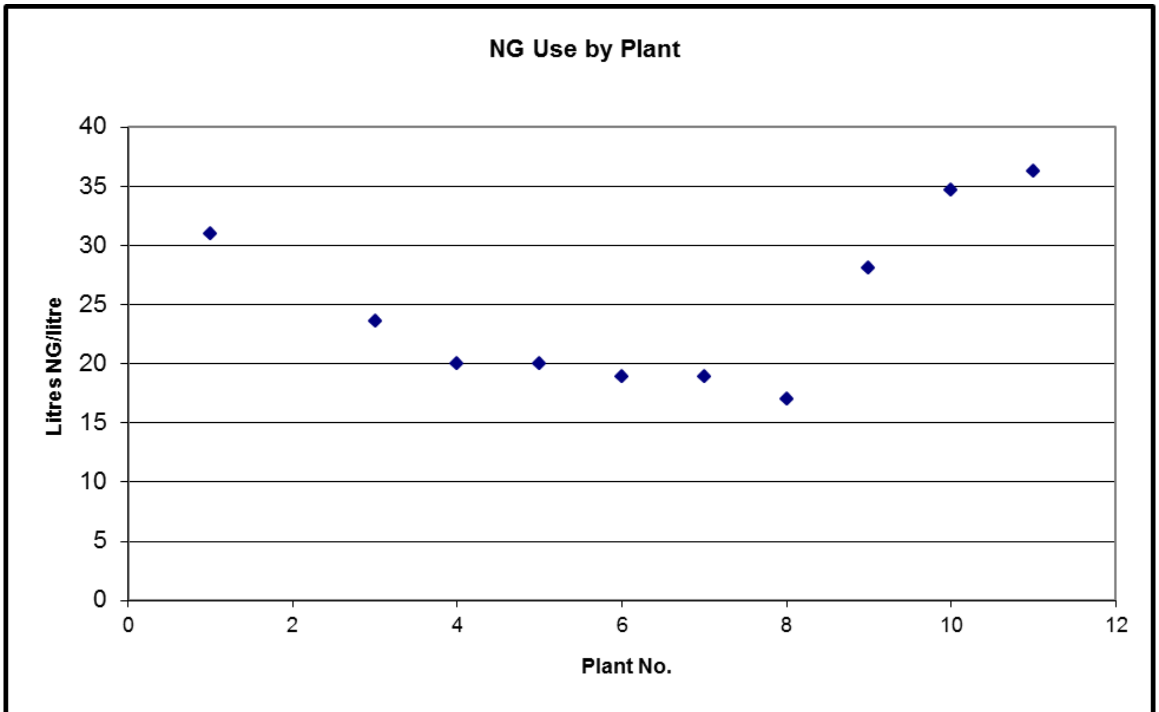
Figure 6-1 Biodiesel Power Use



Source: (S&T)[2]

The data sheet uses 34.7 litres of natural gas/litre of biodiesel produced. The data from the plants that use natural gas in our database use 24.8 litres of natural gas/litre of biodiesel. The information is shown in the following figure.

Figure 6-2 Natural Gas Use in Biodiesel Production



Source: (S&T)[2]

6.3 Capital Costs

The capital cost estimate is based on a small scale production paper. The AgMRC also has a biodiesel production cost model (http://www.extension.iastate.edu/agdm/energy/xls/d1-15biodieselprofitability.xlsx). This model plant is a 100,000 tonne per year plant, half the size of the plant modelled by Force. The capital cost of the smaller plant is $47 million US, whereas the larger Force plant has a capital cost of $46 million US. It is more likely that the capital costs should be about $80 million US.

6.4 Operating Costs

The operating costs are reported to be 0.6 US cents/litre, which is 3% of the capital costs. The low value is a function of the low capital cost and the low % of the capital costs assumed. The AgMRC data indicates that fixed and variable costs, excluding feedstock and energy (and depreciation and interest) are 6 cents/litre, an order of magnitude higher.

There will be some additional revenue from glycerine sales that should be accounted for in the economic data.

7. HVO Diesel Production by Hydrogenation of Vegetable Oil

7.1 Process Description

This is based on the Neste commercial process and the references are all Neste references. Like the biodiesel pathway this one starts with the vegetable oil and excludes the oilseed production and crushing.

This is a very large plant, 800,000 tonnes per year similar to the size that Neste have built in Singapore and Rotterdam. We understand that for future plants Neste is thinking that smaller plants of 200,000 tpy may be preferable. There are trade-offs between the savings from economies of scale and extra logistic costs to source the feedstocks.

7.2 Energy Balance

Most of the energy balance information is from the IFEU report that was prepared before the plants were constructed. Neste has released more recent plant data for the Singapore plant (Neste, 2013). A comparison of the recent data and the technical data in the Force report is shown in the following table.

Table 7-1 Comparison with Recent Neste Data

	Force	Neste
Feedstock, t/tonne diesel	1.23	1.21
Hydrogen consumption, t/t diesel	0.031	0.038
Gasoline co-product, GJ/GJ diesel	0.01	0.0047
Electricity consumption, kWh/litre	0.0	0.082
Electricity co-product, kWh/litre	0.029	0.0
LPG Co-product, GJ/GJ diesel	0.0	0.0589
Natural gas, t/t diesel	0.0	0.013

Neste sells some of the LPG produced to the company that produces the hydrogen and some to the company that produces the steam for the plant. It is important that this is not counted twice, once as a co-product and once as a reduction in NG purchases. The table above does not assume that the co-products substitute for any natural gas.

Neste are achieving higher yields than Force have reported but are using more energy to do so.

7.3 Capital Costs

The capital costs are based on information from Neste and are in line with published information. Per unit capital costs may be higher if smaller plants are considered.

7.4 Operating Costs

The operating costs are estimated at 3% of the capital costs, the same as some of the other processes. These work out to 2 euro cents/litre.

There are also revenues from the sale of the co-products that should be accounted for.

Neste (2014) do publish some financial data for their Renewable Fuels division. This includes two large plants (Singapore and Rotterdam, and two smaller plants (175,000 tpy each at Porvoo, Finland). The latest information is shown in the following table (Neste, 2014).

Table 7-2 Neste Financial Data

	2013	Q1 2014
Sales Volume, kt	1928	488
Gross Margin, $/tonne	498	352
Variable production costs	170	170
Sales margin, $/tonne	328	182
Sales margin, Million Euros	477	65
Fixed Costs, Million Euros	106	26
Depreciation, Million Euros	98	24
EBIT, Million Euros	273	15

This information is not in exactly the same format as used by Force but the fixed costs work out to 4.2 euro cents/litre, which would again suggest that 3% of the capital cost is too low for O&M costs.

8. DIESEL PRODUCTION BY BTL TECHNOLOGY

8.1 PROCESS DESCRIPTION

This technology pathway uses the gasification of biomass combined with Fischer Tropsch synthesis to produce diesel fuel. The integrated process has been demonstrated by companies such as Choren. While Choren went bankrupt, the Choren gasification technology is now owned by Linde.

Two other EU projects utilizing this technology include, the UPM Stracel BTL project in France which is scheduled to start production in 2014, but the AJos BtL project in Finland has been “frozen”.

NREL, in collaboration with Iowa State University and ConocoPhillips, have published a techno-economic assessment of this technology (2010). The analysis was based on corn stover feedstock. This source was used for the technical and economic data for this technology. The NREL report has both a low temperature and a high temperature gasification process. It appears that the data used by Force is derived from the HT process but that is not stated.

8.2 ENERGY BALANCE

There are some inconsistencies between the data provided by Force and the information in the NREL report. The Sankey diagram indicates that 56% of the feedstock energy is recovered as fuel (39% as diesel and 17% as gasoline). The NREL report has the same ratio of gasoline to diesel but reports that only 49.7% of the feedstock energy is recovered as fuel. Both appear to use the LHV basis. The quantity of power produced as a function of the diesel produced is the same in both reports. It is not clear from the Force report where the difference arises.

8.3 CAPITAL COSTS

The plant size is approximately the same in the two reports. The NREL plant is sized at 2,000 dry tonnes of feedstock per day (622,000 tonnes/year) and the Force data is for a 687,000 dry tonne/year plant. The capital cost of the Force plant is $730 million US. The NREL plant is $660 million US. The capital cost per unit of diesel fuel is identical for the two documents but this could change if the product yields were the same in the two processes.

8.4 OPERATING COSTS

Once again, the O&M costs are only 3% of the capital costs which we think is too low. Since there are no operating plants like this in the world it is not possible to verify the operating costs. The NREL fixed and operating costs without depreciation are 4.4% of the capital costs.

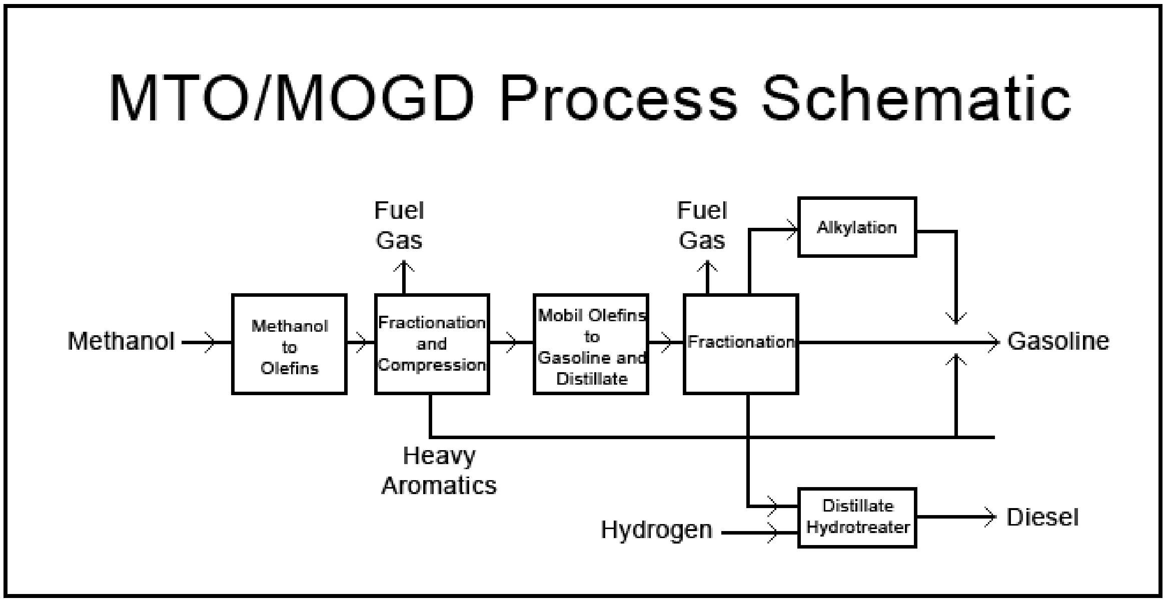
There will be some revenue from electric power sales that will need to be included in the economics. Also reporting the capital and operating costs on the basis of just the diesel production and not on the diesel plus gasoline production makes a comparison to some of the other single fuel technologies difficult.

9. DIESEL PRODUCTION FROM METHANOL

9.1 PROCESS DESCRIPTION

This is a partial fuel pathway in the sense that it starts with a fuel (methanol) and transforms it into another fuel (diesel). The energy balance is provided for the transformation process and not from the original energy source required to produce the methanol. Presumably it would be combined with one of the other pathways that produces methanol. It is a relatively complicated process as shown in the following schematic.

Figure 9-1 MOGD Process Schematic



Source: Tabak et al.

In the 1980s, Mobil operated a methanol to gasoline plant in New Zealand that was technically successful, but was ultimately closed due to economics. The plant was based on technology that was originally developed in the 1970s.

Haldor Topsoe have been developing a methanol to gasoline process and have demonstrated it at a demonstration plant at Houston Texas applying all process steps involved from natural gas to gasoline. Others have been exploring similar routes.

The methanol to diesel fuel route does not appear to have received much attention lately. The two references cited are from 1986 and from 1991.

9.2 ENERGY BALANCE

The Mobil R&D reference does not provide any information on the overall mass or energy balance of the process. It does describe the products that are produced and the range of gasoline to diesel fuel that can be produced under different operating conditions. The maximum diesel to gasoline ratio cited is 4 to one (the basis is unstated).

The Bridgwater and Double reference appears to be the source of most of the technical and economic data but there are some differences between the reference and the Force report. The Force report has a diesel to gasoline ratio of 8.2 on an energy basis, this would be about

7.4 on a volume basis, but the Bridgwater report states that the volume ratio of 1.28 in one place in the report but in the detail datasheets the diesel to gasoline weight ratio is 0.47 and most of the distillate is jet fuel.

The overall methanol to products ratio in the two reports is similar.

Given the age of the references and the discrepancies between the references and the Force report, the technical data would have to be considered speculative unless there is additional work that has been performed that has not been referenced.

9.3 Capital Costs

The capital cost basis in the Bridgwater report is mid-1988. The range of plant sizes reported was 2500 to 7500 tons of methanol per day. The plant modelled by Force is about 1000 tpd of methanol. The original data must be scaled for size and time and should be adjusted for currency exchange rates over time (another 10% in this case).

The Bridgwater capital cost is 90 million pounds for a 2500 tpd plant. This was 162 million USD in 1998. Scaling for size at the 0.7 factor (also used by Bridgwater) reduces the costs to 85 million USD. Adjusting for inflation at 2.5% for 26 years (a 90% increase) would increase the cost to 162 million USD or 116 million euros, the same cost as Force have reported.

The US inflation between 1988 and 2018 was 99.7% (http://www.usinflationcalculator.com/) so the price estimate might be slightly low. The confidence level of the capital cost must be rated low not only because of the large adjustments made for size, inflation and currency but also the uncertainty over the process design differences between the original source and the Force report.

9.4 Operating Costs

Force has used their standard 3% of capital costs for O&M costs which we think are too low. The Bridgwater report used a standard 2.5% of capital for maintenance and 7% for overhead costs.

There will be other sources of revenue for the gasoline and LPG that are produced from this process that should be included in the economic analysis. Depending on the diesel to gasoline ratio that is achievable this revenue could be significant.

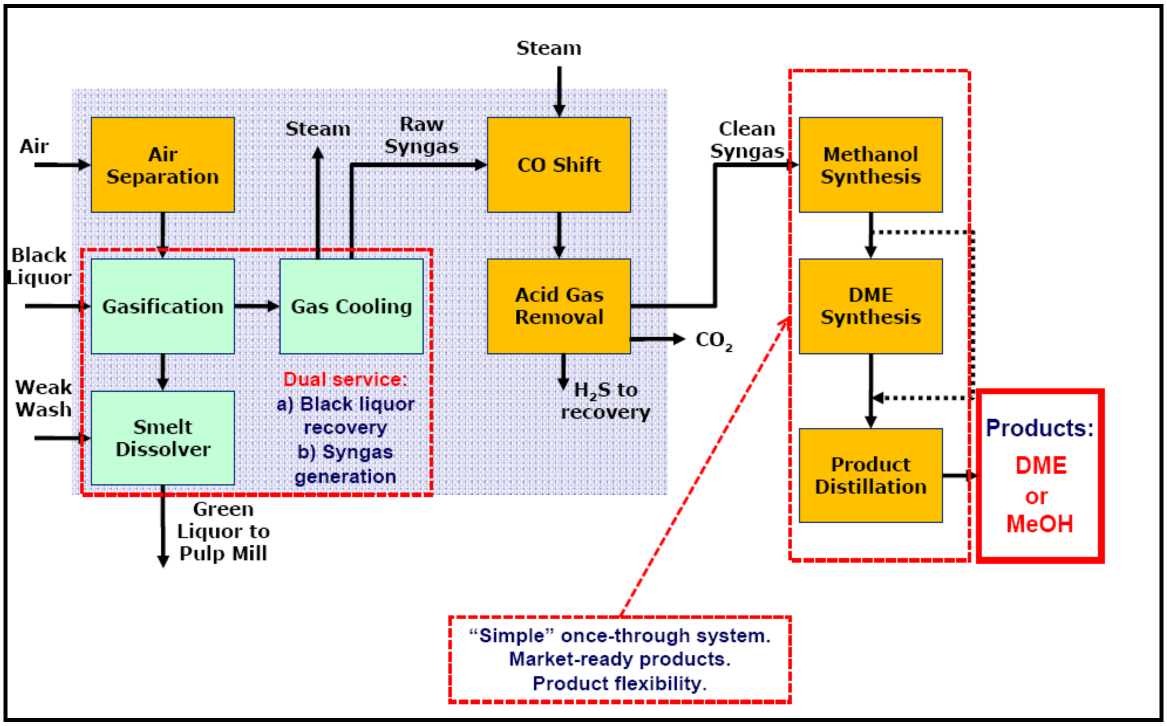
10. DME PRODUCTION BY BTL TECHNOLOGY

10.1 PROCESS DESCRIPTION

This process considers the gasification of wood and the production of DME from the synthesis gas in either a one or two step process.

A similar process is gasifying pulp mill liquor in Sweden and producing DME at a large demonstration plant. The Chemrec/Haldor Topsøe process is shown in the following figure. The Chemrec gasifier is a pressurized oxygen blown unit. The plant operated for several years and the project was completed in 2013.

Figure 10-1 Biomass to DME Process



Source: Chemrec

10.2 ENERGY BALANCE

The energy balance information is reported to be based on a 2011 NREL presentation; however that presentation is for wood to methanol and it appears that it has been converted to a wood to DME plant by just adding a 2% conversion loss of methanol to DME. However the NREL presentation reports LHV efficiency for methanol of 45.8% and Force report 53.2% for DME production which should be lower due to the 2% penalty for the extra conversion step. Both reports assume 50% moisture content in the feedstock.

The Chemrec project reported higher efficiencies but that may be a result of the different feedstock properties.

10.3 CAPITAL COSTS

This plant is 84% of the size of the NREL methanol plant found in the first reference based on feedstock input. The capital cost is 47% higher than NREL arrived at for methanol. Some additional cost is expected for the second stage of the process of converting the methanol to DME. This seems like a steep penalty for the extra process step.

10.4 OPERATING COSTS

Force has used their standard 3% of capital costs for O&M costs, which we think is too low.

11. SYNTHETIC NATURAL GAS PRODUCTION FROM SYNGAS

11.1 PROCESS DESCRIPTION

This pathway involves the gasification of wood pellets and the methanation and cleanup of the produced gas to natural gas quality. The system boundary does not include the pelletization step.

The system is similar to the Gussing gasifier demonstration project undertaken in Austria over the past decade. The data used for this report is based on mostly on Swedish work reported to the IEA bioenergy task on gasification. The Gothenburg Biomass Gasification Project, GoBiGas, is Göteborg Energi's large investment in Bio-SNG through gasification of solid biofuels and forestry wastes. The project has been split into two phases, a first demonstration phase of 20 MW product gas, to be followed by a second phase of 80-100 MW output of product gas.

The plant's inauguration was in March 2014.

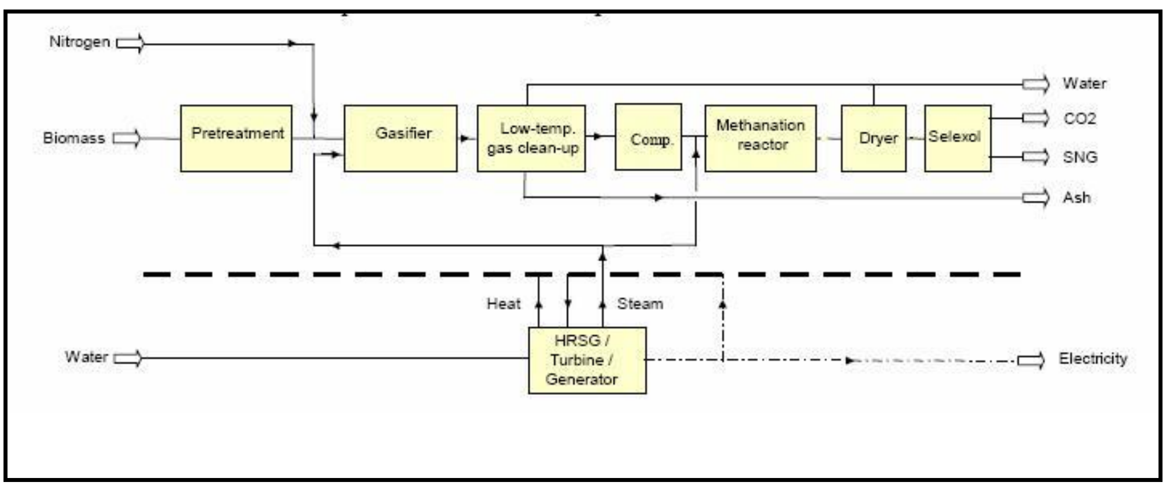
11.2 ENERGY BALANCE

The energy balance data is from the GoBiGas first phase design. It should be possible to verify it with actual plant operating data this year.

We did have a discussion on a LCA of the process with Bram van der Drift (reference 1) at the IEA Bioenergy conference in Vienna. He stated that none had been done and was interested in the GHGenius analysis.

The GHGenius pathway was based on work done in the Netherlands in 2003 (Mozaffarian, et al, 2003). The researchers modelled a Battelle indirectly heated gasifier combined with gas clean-up and a methanation step using Aspen Plus models. The basic process diagram is shown in the following figure.

Figure 11-1 SNG Production from Biomass



Source: Mozaffarian

The overall energy requirements for the process are summarized in the following table. The process purchases some power. The model is flexible enough that if a more efficient process produced power, the emissions from power displaced could be calculated as well.

Table 11-1 Wood to SNG Mass and Energy Requirements

	Used for GHGenius
	Per GJ of SNG (HHV)
Wood input, kg	72.3
Nitrogen, kg	0.033
Power Purchased, kWh	12.02
Carbon conversion	67.0%

The Force pathway requires 90.1 kg of wood per GJ (LHV) of natural gas and the GHGenius value is 72.3 kg/GJ (LHV). So there is quite a difference in the efficiencies that are calculated. The actual operating performance of the Gothenburg plant will be critical to achieve a better understanding of the process.

11.3 Capital Costs

The official projected cost of the Gothenburg plant was 1300 million SEK. This is 143 million Euros for a plant that is one fifth the size of the plant proposed by Force. Even with a scaling factor applied that would be a cost of 440 million Euros compared to the Force estimate of 350 million Euros.

First of kind plants always cost more, which is why the learning factor is applied to early cost estimates. The NREL nth plants typically cost 43% of the pioneer plant (NREL, 2010). Applying this factor would reduce the capital costs significantly. The Force adjustment for the first of kind is only 70%.

This cost estimate is out of line with the other estimates for the other technologies. In the discussion section at the end of this report a comparison table is provided that compares the plant sizes, the energy efficiencies and the per unit capital and operating costs.

11.4 Operating Costs

The operating costs are again 3% of the capital cost. In this case the operating cost estimate may be closer to being realistic because the capital costs are so high.

12. KEROSENE PRODUCTION BY BTL TECHNOLOGY

12.1 PROCESS DESCRIPTION

This pathway is identical to the diesel production by BTL technology pathway except that kerosene is produced instead of diesel.

We question the assumption that the technical data would be identical for the production of kerosene and diesel fuel. There is some discussion in the literature about the selectivity of the FT synthesis stages (see Dry, 2001).

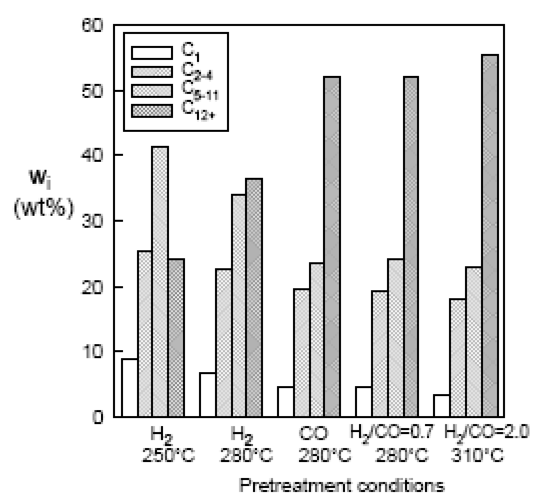
FT synthesis produces a range of products between C_1 and waxes. The actual ranges will vary with process type, catalysts, and syngas quality but there is always a range of products. Tijm (1994) reports on the product distribution for two different process severities as shown in the following table. Unfortunately the paper does not provide the accompanying yield data for the two operating conditions but there is more gasoline produced in the kerosene mode than the diesel mode.

Table 12-1 Product Distributions – Shell SMDS

	Gas Oil Mode	Kerosene Mode
	% wt	
Tops/naphtha	15	25
Kerosene	25	50
Gas Oil	50	25

In his 1999 thesis, van der Lann showed that the quantity of each group of products did vary with operation conditions. This is shown in the following figure where the two right hand bars represent the liquid products and the two left hand bars represent the gaseous products. The sum of the two liquid products (and thus the yield) as well as the ratio of heavy to light liquid products does vary with the pretreatment conditions.

Figure 12-1 Selectivity vs. Yield



Source: van der Lann

12.2 ENERGY BALANCE

See the comments in section 8.2 as they also apply here.

12.3 CAPITAL COSTS

The capital costs are 1 million Euros per GJ higher than the diesel data sheet but this could just be a drag and drop error.

See the comments in section 8.3 as they also apply here.

12.4 OPERATING COSTS

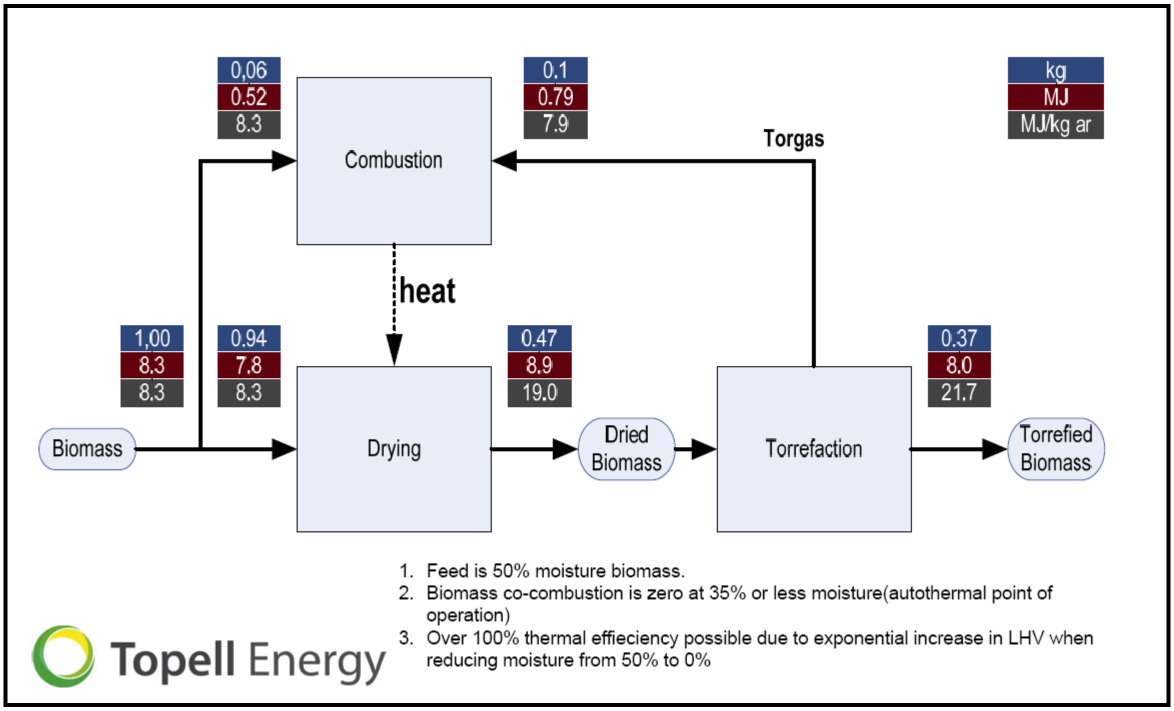
See the comments in section 8.4 as they also apply here.

13. TORREFACTION AND PELLETIZATION OF WOODY BIOMASS

13.1 PROCESS DESCRIPTION

A single source (IEA Bioenergy, 2012) is used for the process and economic data for this process and that IEA report appears to rely mostly on a presentation by the Dutch torrefaction company Topell (2012). The following is a figure from the Topell presentation that is also in the IEA report.

Figure 13-1 Torrefaction Process



Source: Topell Energy

13.2 ENERGY BALANCE

The 97% recovered energy in the torrefied biomass is achieved with some recovery of the heat of vaporization of the water produced from the combustion of wood and Torgas used in the drying process. This may not be achievable in the real world. The IEA report discusses the theoretical energy efficiency in a number of places.

The electric power requirements are 260 kWh/tonne of torrefied pellets, which is the same value as in the IEA report.

There has been a more recent conference IEA Bioenergy conference on torrefaction held in January 2014 (http://www.ieabcc.nl/workshops/task32_2014_graz_torrefaction/index.html). Several other torrefaction suppliers presented information on their systems.

- Trattner (2014) confirmed the electric power requirements of 260 kWh/tonne.
- Wild (2014) presented a less favourable energy balance where only 90% of the wood energy was found in the torrefied product.

13.3 CAPITAL COSTS

The capital costs are from the work by Topell reported in the IEA Bioenergy summary and are reported to be turnkey costs but it is not clear if this includes the working capital requirements which are included in many of the other technologies, including all of the NREL capital cost estimates.

13.4 OPERATING COSTS

Operating costs (0.73 Euros/GJ) are 7.5% of the capital costs. These exclude the feedstock and the electric power. The cost structure from the IEA report is shown in the following table.

Table 13-1 Torrefied Pellets Cost Structure

Cost components	Torrefied Pellets	
	US$/GJ	Euros/GJ
Cost of Biomass	4.28	3.06
Cost of Electricity	0.74	0.53
Cost of Labour	0.47	0.34
Financial costs	1.49	1.06
Other costs	0.43	0.31
Cost Price at Production Site	7.41	5.29

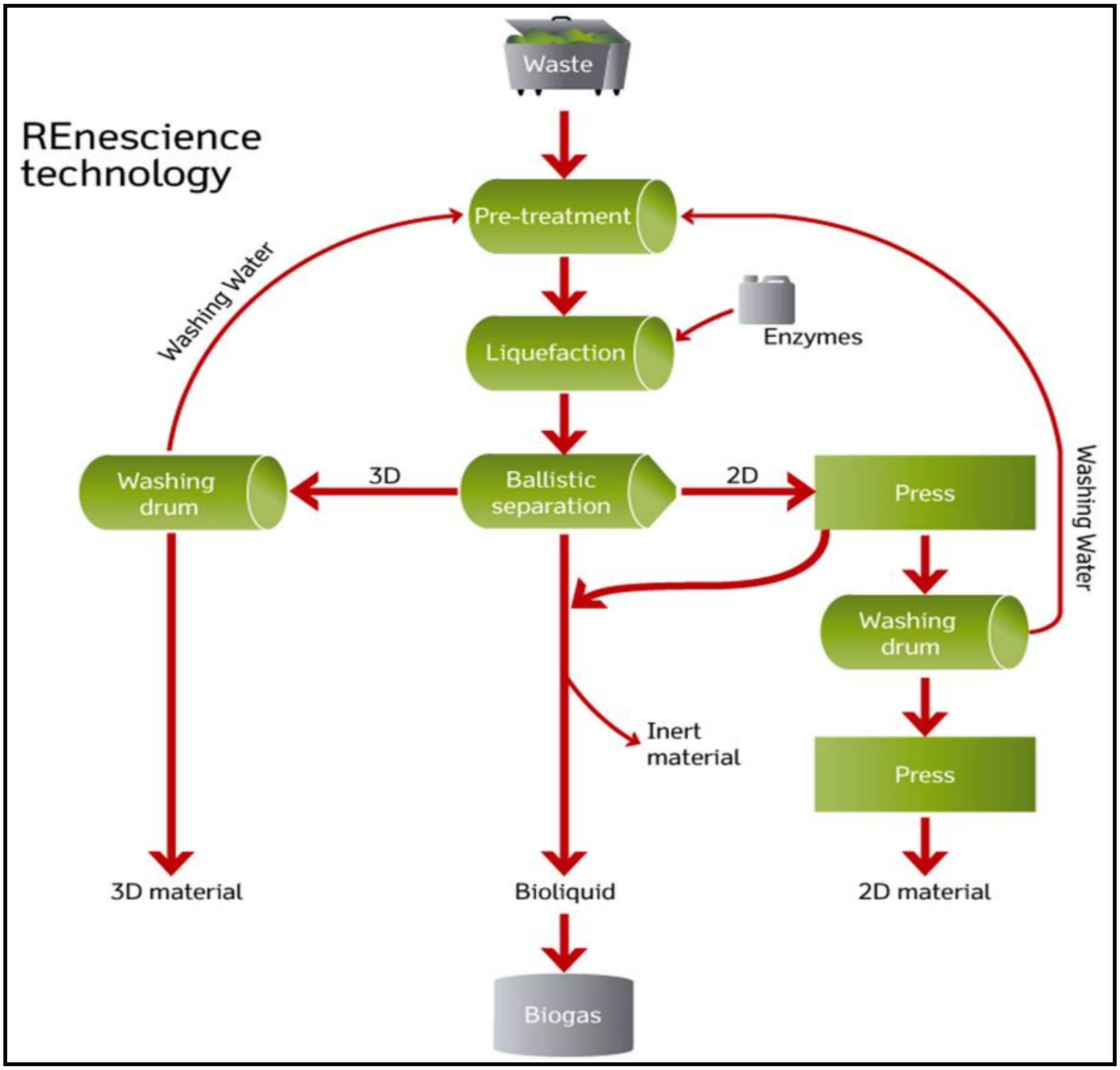
It is not apparent from this table how the 0.73 Euro/GJ O&M costs were arrived at.

14. BIO-LIQUID PRODUCTION BY RENESCIENCE TECHNOLOGY

14.1 PROCESS DESCRIPTION

The REnescience technology separates MSW into fractions. The technology handles MSW without prior treatment such as shredding or sorting. The process runs at low temperatures and at atmospheric pressure to separate the parts of MSW. The process is shown in the following figure.

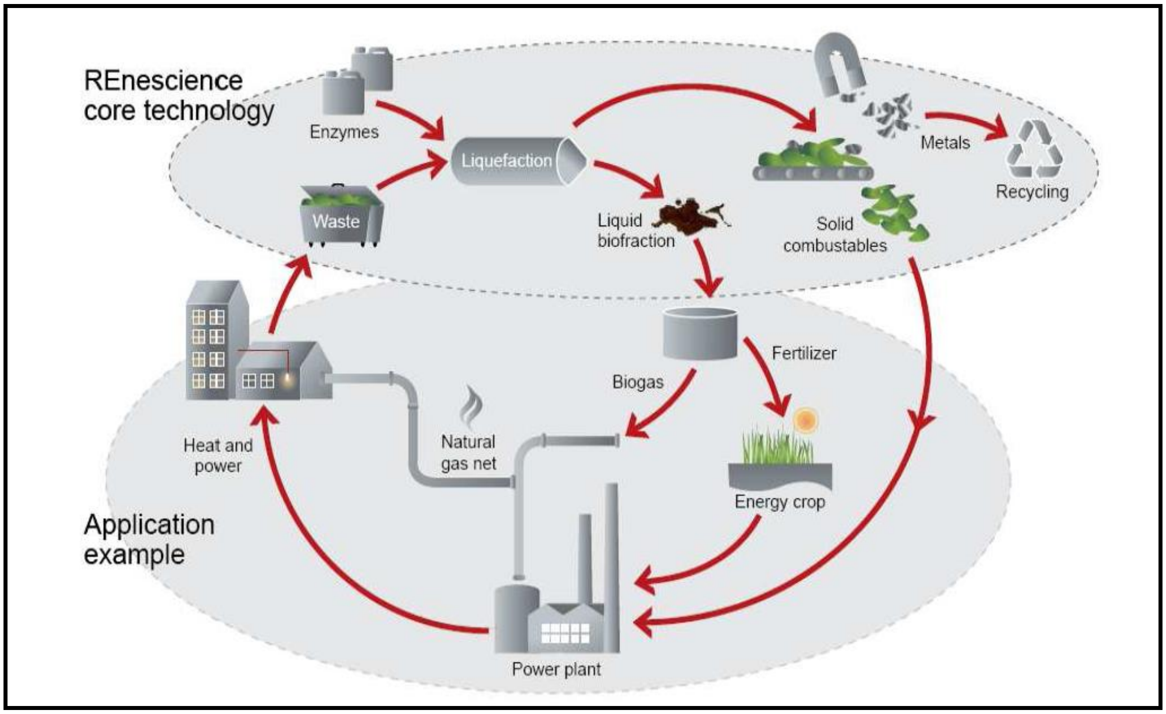
Figure 14-1 REnescience Process



Source: REnescience

The system boundaries are not explicitly stated but it appears that they do not include the biogas production. The system is therefore one that pre-treats MSW and produces RDF and a liquid stream of dissolved organics that could be used for biogas production. The integration of this system into the larger energy supply system is best shown in the following figure from the one reference provided.

Figure 14-2 REnescience System Integration



Source: REnescience

14.2 ENERGY BALANCE

The technical data refers to a single reference; however the reference has little technical data in it so presumably Dong Energy supplied some additional information to Force.

The system does produce two product streams, a solids stream, and an organic liquid stream. The solid stream has twice the energy content of the liquid stream but all but one of the performance metrics (total process energy efficiency) are presented based on the smaller liquid stream being the primary product. This does distort the total system performance metrics.

14.3 CAPITAL COSTS

The capital cost estimate is reported to have been provided by Dong Energy. It is representative of a "close to commercial" stage of development and thus would not be representative of the "nth" plant used for many of the other technologies.

The other issue with the capital cost presentation is that the total costs are divided by just the biogas output. The technology produces biogas and RDF and a better representation of the capital costs would allocate some of the capital to the RDF, especially since the energy content of the RDF is double that of the biogas.

14.4 OPERATING COSTS

The O&M costs are estimated at 5% of the capital costs.

15. ETHANOL PRODUCTION BY INBICON 2ND GENERATION FERMENTATION TECHNOLOGY

15.1 PROCESS DESCRIPTION

This technology is really a specific example of the technology described in section 5 of this report. There are some differences between the systems and these include:

1. Only the C6 sugars are fermented to ethanol in the Inbicon system described here. This results in less ethanol produced per tonne of feedstock.
2. The C5 and Lignin streams are treated as co-products for sale in the Inbicon system rather than used for ethanol and energy production in the generic system in section 5.
3. Power and heat are purchased in the Inbicon system rather than being self-generated in the generic system.
4. Inbicon includes an anaerobic digestion system to produce biogas as a product as part of the process and the generic system has an anaerobic and aerobic digester as part of the wastewater treatment system with the biogas being used in the process to produce electricity.

15.2 ENERGY BALANCE

The energy balance information for the Inbicon technology and the NREL technology discussed in section 5 is summarized in the following table.

Table 15-1 Energy Balance Comparison

	Generic NREL	Inbicon
Plant size, t ethanol/year	200,000	58,000
Feedstock, tonnes/year	900,000	400,000
Yield, l ethanol/tonne	281	183
Total energy input, raw materials, GJ/GJ ethanol	2.4	3.7
Process energy efficiency, ethanol, %	41.1	22.7
Total process energy efficiency, ethanol + co-products, %	44.1	85.6
Estimated total energy efficiency with utilization of process heat loss for district heating	71	95.7

The NREL plant processes about twice the feedstock but because it converts C5 and C6 sugars the ethanol yield is 3.4 times greater. Since ethanol production is the denominator in many of the technology metrics this skews the metrics in favour of the NREL technology.

When all of the co-products and the district heat are considered then the Inbicon technology looks better. He issue is that not all of the co-products have equivalent value or utility. C5 sugars can be converted to ethanol but there will be some loss of energy, similarly the lignin and biogas can be converted to electric power but again with a loss of efficiency. Essentially the metric are forcing comparisons between fuel and energy with potentially misleading results.

15.3 CAPITAL COSTS

The capital costs for this technology are based on a first of kind plant that is also the basis for the next section. This is not the same as the n^{th} plant basis used for the generic NREL plant. Nevertheless the capital costs for the two systems are compared in the following table.

Table 15-2 Capital Cost Comparison

	Generic NREL	Inbicon
Plant size, t ethanol/year	200,000	58,000
Feedstock, tonnes/year	900,000	400,000
Yield, l ethanol/tonne	281	183
Total capital cost, million Euros	370	256
Total capital cost, Euros/GJ/year	69.0	164.7

The Inbicon per unit capital costs are higher than the NREL capital costs but there are a number of reasons for this.

1. The issue of first plant vs. the n^{th} plant.
2. The lower ethanol yield, but this will be offset by greater revenue from other co-products.
3. The smaller plant size doesn't offer the same economies of scale.

The nth plant issue alone could reduce the Inbicon capital cost per GJ to the same value as the NREL estimate which would indicate that if the adjustments were also made for the plant scale and ethanol yield, the Inbicon capital costs could be less than the NREL estimate.

Both technologies have revenue form additional streams, electricity for the NREL system and molasses, lignin and biogas for the Inbicon system. This makes a direct comparison of the project economics difficult based on the metrics reported in the Force report.

15.4 OPERATING COSTS

The operating cost comparison between the Inbicon system and the NREL system are shown in the following table.

Table 15-3 Operating Cost Comparison

	Generic NREL	Inbicon
Plant size, t ethanol/year	200,000	58,000
Feedstock, tonnes/year	900,000	400,000
Yield, l ethanol/tonne	281	183
O&M, Euros/GJ/year	5.3	23.1
% of capital cost	7.7	14.0

Some of the difference can be explained by the lower ethanol yield and some by the difference in the scale of the plants. However these two factors would not account for all of the difference.

16. ENERGY AND FUEL PRODUCTION BY MAABJERG ENERGY CONCEPT BIO-REFINERY

16.1 PROCESS DESCRIPTION

This technology is similar to the previous Inbicon system except that the system is more integrated. The size of the core Inbicon system is the same as the previous technology but this system has additional manure and MSW feedstocks and consumes some of the lignin to produce heat for the system.

The same quantity of ethanol is produced but more biogas is produced and there is more process heat available. The metrics are presented on the basis of the total quantity of fuel produced (ethanol plus biogas).

16.2 ENERGY BALANCE

The energy balance information for the Inbicon technology and the Maabjerg technology is summarized in the following table. The Inbicon metrics are per GJ of ethanol and the Maabjerg metrics are per tonne of fuel, which includes ethanol and biogas. While same core Inbicon technology is used in both systems the conversion of some of the Inbicon co-products to energy and the addition of some MSW and manure more than doubles the energy output from the system.

Table 16-1 Energy Balance Comparison

	Inbicon	Maabjerg
Plant size, t ethanol/year	58,000	58,000
Plant size, GJ/year output	1,554,400	3,650,000
Feedstock, tonnes/year	400,000	934,000[1]
Feedstock, GJ/year	5,751,300	7,154,000
Yield, l ethanol/tonne	183	183
Total energy input, raw materials, GJ/GJ ethanol (/GJ Fuel)	3.7	1.96
Process energy efficiency, ethanol, %(/GJ Fuel)	22.7	49
Total process energy efficiency, ethanol + co-products, %	85.6	67
Estimated total energy efficiency with utilization of process heat loss for district heating	95.7	99

16.3 CAPITAL COSTS

The capital costs are compared to the Inbicon example in the following table. The addition conversion of co-products to energy has increased the plant capital cost by 70% to 436 million Euros. The capital costs per unit of energy delivered crops by 27% to 119 Euros per GJ as a result of the increased conversion of co-products to energy.

[1] The manure quantity appears to be reported on a wet basis.

Table 16-2 Capital Cost Comparison

	Inbicon	Maabjerg
Plant size, t ethanol/year	58,000	58,000
Plant size, GJ/year output	1,554,400	3,650,000
Feedstock, tonnes/year	400,000	934,000[2]
Feedstock, GJ/year	5,751,300	7,154,000
Yield, l ethanol/tonne	183	183
Total capital cost, million Euros	256	436
Total capital cost, Euros/GJ/year	164.7	119.4

The Maabjerg concept is a better comparison to most of the other technologies since more of the feedstock is converted to energy than in the Inbicon scenario modelled.

16.4 OPERATING COSTS

The operating cost comparison between the Inbicon system and the Maabjerg system are shown in the following table. The total O&M costs rise by 23% but on a unit of fuel produced basis they drop by 48% as the quantity of fuel produced more than doubles.

Table 16-3 Operating Cost Comparison

	Inbicon	Maabjerg
Plant size, t ethanol/year	58,000	58,000
Feedstock, tonnes/year	400,000	934,000
Yield, l ethanol/tonne	183	183
O&M, million Euros/year	35.9	44.1
O&M, Euros/GJ/year	23.1	12.1
% of capital cost	14.0	10.0

[2] The manure quantity appears to be reported on a wet basis.

17. DIESEL PRODUCTION BY BTL TECHNOLOGY WITH HYDROGEN ADDITION

17.1 PROCESS DESCRIPTION

One of the challenges of using biomass for the production of fuels via the Fischer Tropsch process is that the gasification of biomass does not produce the ideal ratio of CO to Hydrogen required for the fuel synthesis. It is deficient in hydrogen.

This technology is the same as the one described in section 8 of this report, except that the syngas from biomass gasification is augmented with supplemental hydrogen. This is a theoretical pathway and the energy balance has been calculated by Force based on stoichiometric assumptions. The source of hydrogen is not specified.

17.2 ENERGY BALANCE

The energy balance is based on the data for the BTL to diesel process and the addition of hydrogen to maximize the use of the carbon in the biomass. The hydrogen source is not specified and the energy balances are presented on the basis of the hydrogen energy content and not on the basis of the energy required to produce the hydrogen. The later approach would increase the energy into the overall system by amount 15%.

The energy balance of this technology is compared to the energy balance of the technology presented in section 8 in the following table.

Table 17-1 Comparison Showing the Impact of Hydrogen Addition

	Diesel from BTL	Diesel from BTL plus H_2
Plant size, t/year	105,000	149,700
Straw input, t/year	808,000	823,350
Hydrogen, t/year	0	34,300
Process energy efficiency, %	39.3	41.3
Total process efficiency, including co-products, %	59.1	61.1
Total efficiency including district heat, %	80	80

The addition of supplemental hydrogen increases the output from the same quantity of biomass by about 43%, however it only has a minor positive impact on the presented process efficiencies and if the energy required to produce the hydrogen was included the overall process efficiency would actually be lower than the base system.

17.3 CAPITAL COSTS

The comparison of the capital costs of the base case and the supplemental hydrogen case is presented in the following table.

Table 17-2 Capital Cost Comparison

	Diesel from BTL	Diesel from BTL plus H_2
Plant size, t/year	105,000	149,700
Capital Cost, million Euros	522	553
Capital Costs, Euros/GJ Diesel	112.9	84.0

The capital cost increase for the additional hydrogen seems modest but it is not clear if this includes the cost of manufacturing the hydrogen. It may be just the additional cost for the BTL manufacturing facility.

17.4 Operating Costs

The impact of the hydrogen addition on the operating and maintenance costs is shown in the following table. It would appear that the same 3% assumption used for many of the technologies has been applied. If the production of hydrogen is not included in the capital costs then the O&M costs of the hydrogen would not be included in the these estimates.

Table 17-3 O&M Cost Comparison

	Diesel from BTL	Diesel from BTL plus H_2
Plant size, t/year	105,000	149,700
O&M Costs, Euros/GJ Diesel	3.4	2.5
O&M Costs, % of Capital Cost	3 %	3%

As with the BTL technology described in Section 8, we think that the O&M costs for this system are also too low.

18. SNG Production by Methanation of Biogas

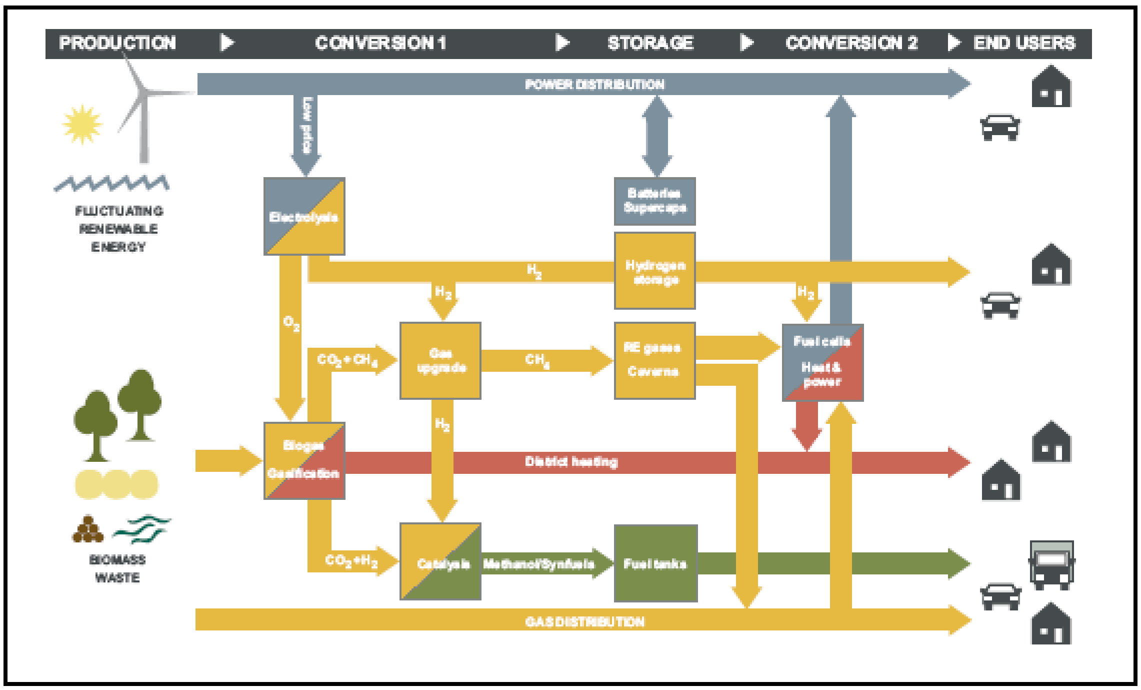
18.1 Process Description

There are two approaches that can be applied to convert biogas (a blend of methane and CO_2) to pipeline quality natural gas. Either the CO_2 can be removed through a process such as pressure swing adsorption; of the CO_2 can be methanated with the addition of addition. This technology used the second approach.

These biogas systems are typically much smaller than the other technologies included in this report as there are often limits on the feedstock availability and the physical size of the reactors. This system is an order of magnitude smaller than the other systems studied here.

There are no references provided for the technology. The data appears to be from the Danish Partnership for Hydrogen and Fuel Cells (http://www.hydrogennet.dk/brintidk0/). However the vision document provides for detailed information on the various concepts provided. The concept is covered in the partnerships vision for the future energy supply in Denmark as shown in the following figure.

Figure 18-1 Energy Value Chain Vision



Source: Danish Partnership for Hydrogen and Fuel Cells

18.2 Energy Balance

Unlike the previous system, this system includes the energy used to produce the hydrogen required for the process. In this case it is assumed that the hydrogen will be produced through electrolysis. Almost equal quantities of electric energy and biogas are used in the system and depending on how the electricity is produced there could be more fuel used for the hydrogen than is used to produce the biogas.

The process is quite simple with no co-products and just some process heat available for recovery in a district heating system. The biogas production process is also exothermic and some heat for district heating might be available from that stage but that is outside of the system boundary as described here. The biogas production being outside of the system boundary improves the process and economic metrics since the energy losses associated with the biogas production are outside of this system.

The simple concept also leads to improved metrics since all of the output energy is included in the denominator.

It is not clear if the hydrogen system efficiency used here is the same as was used for the methanol from ETL technology.

18.3 Capital Costs

It is not clear from the information provided if the biogas production is included in the capital cost estimate.

18.4 Operating Costs

The O&M costs for this technology are only 2% of the capital costs. Again it is not clear if this includes the biogas production system.

19. SUMMARY AND DISCUSSION

There are many challenges when this type of analysis is undertaken. First, the systems that are compared are at various stages of development, some are commercial, and some are at early stages of development with any number of possibilities in between those extremes. This makes it very difficult to normalize the data.

Second, the information that is available for the different systems may not be consistent. One can make attempts to provide consistency by scaling data so that plant sizes are comparable or applying inflation factors so that costs are presented for the same year, or trying to adjust the data so that it is all representation of a fully commercial and mature system but in many cases the detail information on the systems may be silent about critical aspects, for example is working capital included in the capital cost estimates or not?

Third, it is just not possible to verify some of the data that project developers present. Have they actually achieved the performance that they suggest or are they presenting information based on what they expect to achieve with additional development?

Force has assembled a dataset for seventeen technologies and delivered a consistent set of metrics for each of the technologies. It is apparent that in a number of cases estimates have had to have been made as the data is not yet available; this is particularly true of O&M costs where a percentage of the capital cost is used in many cases. We think that in many cases these estimates are too low.

Another challenge that Force faced was how to deal with systems that produce more than one product or have co-products. How these are dealt with will influence the reported metrics and ultimately the economics of the processes. In most cases, the co-products have been excluded from the metric and the analysis but the comparison of the Inbicon and the Maabjerg systems shows how important the treatment of co-products to the technical and economic metrics is to the results. Maabjerg converts the Inbicon co-products to energy and thus includes them in the energy and economic metrics and they are largely excluded in the Inbicon system because they are co-products.

The following table has been prepared to summarize the primary findings of the Force report. For each of the technologies, the plant size, two different approaches to plant efficiency, the capital cost and the O&M costs are presented.

Table 19-1 Technology Summary

Technology	GJ/Year	Process Energy Efficiency, Fuel	Total Process Energy Efficiency, Fuel + Coprods	Capital Cost Euro/GJ	O&M, Euro/GJ	O&M, % Cap Cost
Bio-Methanol	5,970,000	52.9%	52.9%	35.1	1.1	3.1%
Methanol from CO_2 and Electricity	796,000	53.5%	53.5%	44.9	1.35	3.0%
1st Gen Bio-Ethanol	5,360,000	45.5%	76.5%	18.6	2.05	11.0%
2nd Gen Bio-Ethanol	5,360,000	41.1%	44.1%	69	5.3	7.7%
1st Gen Biodiesel by transesterification	7,460,000	91.0%	95.6%	4.4	0.13	3.0%
1st Gen HVO Diesel	35,200,000	88.6%	90.8%	19.4	0.58	3.0%
2nd Gen Biodiesel	4,620,000	39.9%	59.1%	112.9	3.4	3.0%
Diesel from Methanol	5,280,000	77.5%	91.1%	21.9	0.66	3.0%
Bio-DME	6,248,000	53.2%	53.2%	43.7	1.3	3.0%
BioSNG	2,970,000	56.3%	56.3%	118	3.5	3.0%
2nd Gen Bio-Kerosene	4,620,000	39.3%	59.1%	113.9	3.4	3.0%
Torrefied Wood Pellets	2,170,000	92.8%	92.8%	10.4	0.73	7.0%
Bio-liquid	229,813	25.6%	76.0%	116.8	5.84	5.0%
2nd Gen Bio-Ethanol Inbicon	1,554,400	85.6%	95.7%	164.7	23.1	14.0%
Maabjerg Energy Concept	3,650,000	67.0%	99.0%	119.4	12.1	10.1%
2nd Gen BioDiesel w/ Hydrogen Addition	6,587,000	41.3%	61.1%	84	2.5	3.0%
SNG by methanation of biogas	179,500	80.3%	80.3%	24.4	0.49	2.0%

19.1 System Boundaries

The described systems do not all have the same system boundaries. The best example is the comparison of the last two technologies. With the second gen biodiesel with hydrogen production, the hydrogen is an input (produced outside of the system boundary) and with the SNG from biogas, the hydrogen required for the system is produced inside the system boundary. The different treatment impacts the efficiencies, the plant capital costs, and the O&M costs.

19.2 Plant Size

There is factor of 20 between the largest plant and the smallest plant in terms of energy output. While there are technical factors for this, care must be taken when any comparison of the process metrics are undertaken.

19.3 PROCESS EFFICIENCY

Up to three different metrics are presented for process efficiencies depending on the technology.

19.3.1 Without Co-products

The process efficiency without co-products is the least useful metric. Many of the technologies produce significant co-products and excluding them from the analysis presents an unbalanced view of the process.

19.3.2 With Co-products

Including any co-products produced the best means of comparison between the technologies assuming that the system boundaries are comparable.

19.3.3 With District Heat

Including the potential energy recovery for district heating will tend to narrow the differences between the technologies. While this may be appropriate for Denmark, other jurisdictions may not have the same opportunities and that could influence the rate at which the technology is employed and rate at which the learning experiences are gathered.

19.4 CAPITAL COST

The capital cost estimates came from a number of different sources and are presented on different basis. Many were derived from NREL reports and are representative of the n^{th} plant. Others represent the first plant and are therefore higher cost that the n^{th} plant. An attempt should be made to present the capital costs on the same basis.

The different system boundaries will also impact the capital cost estimates but moving the costs in or out of the system boundary.

19.5 O&M COSTS

The O&M cost presentation appears to be quite variable and probably the values with the lowest level of confidence in the reports. This is not unexpected since many of the technologies are not yet in production.

19.5.1 Actual Values

In the cases of the commercial technologies, the O&M costs estimated by Force are lower than information that we have on these systems.

19.5.2 Percentage of Capital Costs

While the percentage of capital cost basis is often found in work of this kind we think that the estimates provided by Force are too low.

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