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Advanced Biofuels – Potential for Cost Reduction

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Executive Summary

- Bioenergy already plays an important role in the global energy economy, and it's expanded use is a critical element in future low carbon scenarios, where it can especially play an important role in reducing greenhouse gas (GHG) emissions from the transport sector. Decarbonising transport will require a range of bio-based transport fuels, and especially advanced low carbon fuels which are suitable for long-haul transport applications including aviation. A number of appropriate technologies to produce such fuels are being developed and commercialised. However so far, their production has only reached a limited scale.

- The costs of these advanced biofuels are currently higher than those of the fossil fuels which they can displace and of more conventional biofuels such as ethanol from sugar or corn, or biodiesel. It is therefore important to consider what scope there is to reduce the production costs of a range of advanced biofuels, and to identify under what conditions they could become affordable.

- This project uses as its starting point a study on the costs of advanced biofuels carried out within the programme of work of the Sub-Group on Advanced Biofuels (SGAB) (under the European Commission's Sustainable Transport Forum (STF)) and published in 2017. The report on this study reviewed data available on the current costs of producing a range of advanced biofuels, based on extensive contact with industry and other players active in the field. The aims of this project are to:

    - Update and extend the SGAB study to provide estimates of the current costs of producing a selection of relevant advanced biofuels;

    - Identify the scope for cost reduction for these advanced biofuels;

    - Develop a model for likely cost reduction progress as deployment grows;

    - Compare these costs and cost trajectories with likely trends in fossil fuel prices, and those of conventional biofuels.

    - Examine the impact of policy measures, including carbon pricing, on the economic competitiveness of advanced biofuels.

- Information gathered from industry and other sources for this study has largely confirmed the estimates of the current costs of producing advanced biofuels contained in the earlier SGAB cost analysis report. Costs lie in the range of 65 to 158 EUR/MWh (17-44 EUR/GJ) for production based on biomass feedstocks and 48 to 104 EUR/MWh (13-29 EUR/GJ) for waste-based production, illustrating the cost advantages of using waste feedstocks.[1] This compares with a recent range of fossil fuel prices of 30-50 EUR/MWh (8–14 EUR/GJ).

- Early market opportunities exist for producing lower cost advanced biofuels from wastes, and through integration of advanced biofuel production with existing biofuels processing plants. However, such opportunities are relatively limited and will not in themselves enable

[1]Many different units are used to describe energy and energy costs. In this report the costs are principally presented in terms of EUR/MWh and in EUR/GJ in summary information. A range of energy and energy cost conversion factors are provided in Appendix 4.

production at levels likely to be needed to meet low carbon scenario expectations.

- There is significant potential for cost reduction through R&D and through experience being gained in the current generation of demonstration and early commercial plants. If a number of additional commercial plants are built, it is anticipated that capital and operating costs could be significantly reduced, while scope for feedstock cost reduction is judged to be more limited. Overall production costs could be reduced by between 5-27% compared to the current cost estimates. In addition, if increased experience makes it possible to finance plants on more favourable terms which would reduce costs further. For example, reducing the financing rate from 10% to 8% and extending the financing term from 15 to 20 years would further reduce costs by some 5-16%. Taken together these measures can reduce the production costs range for biofuels produced from biomass feedstocks to between 42 and 119 EUR/MWh (12-33 EUR/GJ) and 29-79 EUR/MWh (8-22 EUR/GJ) for waste-based fuels.

- Large scale deployment of the technologies, in line with the patterns needed to meet the ambitions for advanced biofuels within a number of low carbon scenarios, could lead to additional significant cost reductions through technology learning, if plant capital and operating costs fall in line with a learning curve. Such reduction could be significant given large scale roll-out of the technologies (potentially up to 50% further reductions in the most optimistic cases studied), although given the range of complicating factors it is difficult to estimate the scope for such reductions precisely.

- As capital and operating costs fall, the feedstock costs assume a greater importance in the overall cost structure. It is difficult to predict feedstock cost and price trends particularly in situations where demand is significantly scaled up. While global and regional studies indicate that significant quantities of wastes residues and energy crops could be available at roadside costs below 20 EUR/MWh (5.6 EUR/GJ), more detailed studies are needed to confirm that feedstocks could practically be delivered at these costs taking all the logistical and market factors into account.

- Comparison of the estimates of the current costs of production of the range of advanced biofuels with the prices of the fossil fuels that they aim to replace indicates a significant cost gap of between 12 and 128 EUR/MWh (3-36 EUR/GJ). If the medium-term cost reductions discussed above can be achieved this gap could be narrowed but it will still be significant for many of the pathways.

- Policy support will be therefore be needed to enable these technologies to mature either in terms of added value for low carbon fuels or a substantial carbon costs applied to fossil fuels. For biomass based fuels a carbon price in the range of 49-525 EUR/tonne CO_{2eq} would be needed to bridge the current gap. This would be reduced to 0-365 EUR/tonne CO_{2eq} if the medium term cost reductions discussed above are achieved, and could be reduced further by cost reductions linked to learning effects stimulated by large-scale deployment.

- In the longer term, the effective cost of using fossil fuels may rise through a combination of higher prices and more extensive carbon pricing, or other incentives may be available for low carbon transport fuels. If there is an extensive increase in the production capacity of advanced biofuels at the scale envisaged within low carbon scenarios, then there is the prospect of the technologies being cost effective in the context of anticipated fossil and carbon prices such as those in the IEA's World Energy Outlook scenarios.

- While the costs of advanced biofuels and other fuels discussed above are an important factor, a broader range of issues also need to be considered when comparing these and other low-carbon options. These issues include the extent to which they can directly replace fossil fuels, the costs of any modifications or of distribution costs associated with the fuels, the likely availability of feedstocks and the life-cycle GHG emissions and other sustainability criteria associated with particular routes. The overall consideration of the future for advanced biofuels need to be seen in the context of all these other factors as well as the energy costs.

- Large scale deployment will depend on continuing policy support. First, industry will need support during the risky and costly demonstration and early commercialisation of the technologies, so as to bridge the "valley of death". Continuing strong support will also be needed to offset the differences between biofuels and fossil fuel prices, either by internalising external costs associated with GHG emissions associated with fossil fuel use or by incentivising low-carbon transport fuels.

- There are some examples of policy and regulatory portfolios which have been introduced and are successfully leading to some early deployment and use of advanced biofuels. For example, in the US state of California the federal level Renewable Fuel Standard (RFS) and state-level Low Carbon Fuel Standard together provide effective market support at levels which are sufficient to stimulate the growth of advanced biofuels in the California market. Similar policy support measures are being introduced in other regions and the impact and costs of such policies should be monitored so that policy best practice can be identified and applied more widely.

1. Introduction

1.1 BACKGROUND

A number of recent studies highlight the important role that bioenergy already plays in the global energy economy and the critical role it can have in a future low carbon economy. The International Energy Agency (IEA) has noted that bioenergy is the most important renewable energy technology today in terms of its contribution to global final energy consumption, providing 13% of global energy needs (IEA, 2018). Some two-thirds of this is provided by the traditional use of biomass for cooking and heating in emerging and developing countries, which in many cases is not considered as a sustainable practice. More modern uses of bioenergy for heating, electricity production and for transport make up 5% of final global energy consumption. Sustainable bioenergy at present provides a contribution to final energy consumption which is around five times higher than those from wind and solar combined. Biofuels provide the only sizeable source of renewable liquid and gaseous fuels, providing some 3% of global transport energy.

The role of bioenergy in future low-carbon energy futures has also been emphasised.

- In the IEA's 2DS Scenario, the contribution of bioenergy increases 4-fold by 2060 (IEA, 2017). In this scenario, the contribution of biofuels in transport rises 10-fold by 2060, approaching 30 EJ and providing around 30% of the transport sector's total energy needs, with particularly important roles in aviation, shipping and other long-haul transport.

- In the International Renewable Energy Agency's (IRENA) REMap scenario, an increase in renewables and improvements in energy efficiency provide over 90% of the necessary energy-related CO_2 emission reductions to 2050 (IRENA, 2018). In this scenario, bioenergy provides 22% of total global energy needs for transport.

To succeed in playing these important future roles in transport, there will be a need for new technologies that can produce biofuels that can be used in sectors that are difficult to decarbonize in other ways, such as aviation, shipping and other long-haul transport. The new biofuels will need to be suitable for these end-uses, be produced from sustainable feedstocks, and have very low associated greenhouse gas (GHG) emissions, complementing more established conventional biofuels such as ethanol from feedstocks such as grain and sugars, Fatty Acid Methyl Ester (FAME) and Hydrotreated Vegetable Oils (HVO).

A range of interesting technologies and routes to renewable fuels which promise to meet these needs are under development. However, they are not yet fully commercialised or operating at scale. The status of the technologies has recently been reviewed by the Alternative Renewable Transport Fuels Forum (ART Fuels Forum) (Landalv, et al., 2018). So far production of these fuels is at a low level. The scenario assumptions imply a massive scale up in capacity and production – with of the order of over 4,000 large scale production plants needed to produce the necessary fuel.[2]

The production costs of advanced biofuel options are currently higher than both those of their fossil fuel counterparts and of conventional biofuels, on an energy basis. It is therefore important to understand the potential for cost reduction. This could come about through Research & Development

[2] Assuming a production capacity for each plant equivalent to 200MW – see Section 4.3.

(R&D) and through increased experience, which can lead to cost reductions through:

- Reductions in feedstock production and logistics costs, and delivery of feedstock with consistent quality (although this may be offset by increasing feedstock prices driven by increased demand and the need to move to higher costs feedstocks).
- Technical process performance improvements and cost reductions.
- Realising benefits of scale through increases in plant capacity.
- Experience of building and operating large-scale production plants.
- Capital and financing for plants becoming available on more favourable terms, as risks are reduced and confidence in the technologies grow.
- Co-location and integration of advanced technologies in existing fuel or industrial production infrastructures (bio-based and fossil-based) and potentially to carbon capture and use or storage.

From a policy perspective, it is important to understand if and under what conditions these novel advanced biofuels and low-carbon fuels could be affordable compared to other fuels used in the respective sectors. This can help to understand how much financial support will be required to support the new technologies during the demonstration and initial commercialisation phases. Understanding the potential for cost reduction also allows assessments of the need for and likely cost of policies that promote the development of such fuels, and of the likely total public and private investment needed to achieve the targets.

1.2 THE SUB-GROUP FOR ADVANCED BIOFUELS (SGAB) COST STUDY

This project uses as its starting point a study on the costs of advanced biofuels carried out within the programme of work of the Sub-Group on Advanced Biofuels (SGAB) (under the European Commission's Sustainable Transport Forum) and published in 2017 (Landalv, et al., 2017). The report on this study reviewed data available on the current costs of producing a range of advanced biofuels, through extensive contact with industry and other players active in the field. A parallel study carried out under the SGAB looked at the extent to which the various technologies had been commercialised at scale. This status study has recently been updated under the aegis of the ART Fuels Forum (Landalv, et al., 2018).

For the SGAB cost study, a questionnaire was developed to establish the status of particular technical developments and to assess the current costs of production. This approach was successfully used to create a dialogue with project developers who were willing to provide detailed information. The technology performance and cost data provided were reviewed for consistency with other known sources (to avoid over optimistic cost figures) and then estimated cost ranges were "played back" to the participants to get their acceptance of the collated cost data and resulting figures.

1.3 PROJECT OBJECTIVES

This project extends the SGAB cost study by updating information on the current costs of advanced biofuels, and by establishing the scope for cost reduction through dialogue with industry. The aims of this project are to:

- Identify the current costs of producing a selection of relevant novel advanced biofuels;

- Identify the scope for cost reduction for these advanced biofuels;
- Develop a model for likely cost reduction progress as deployment grows;
- Compare these costs and cost trajectories with likely trends in fossil fuel prices, and those of conventional biofuels;
- Examine the impact of policy measures, including carbon pricing, on the economic competitiveness of novel biofuels.

2. Methodology

The project was carried out in three main phases:

- Data collection.
- Data analysis and modelling.
- Benchmarking.

2.1 DATA COLLECTION

This phase of the project aimed to gain updated information from project developers and experts in the EU, North America, Brazil and other regions to update and extend the prior work carried out under SGAB Cost Study. The project also aimed to identify the potential for further cost reduction, based on industry expert views.

The study built on the approach used in the SGAB's Technology Status Report and Cost of Biofuels Reports. The questionnaire used in that work was expanded with some additional questions added to collect technical status information for pathways not included in the previous SGAB work, and also to identify the scope for further cost reduction.

In order to protect commercial security, the report has aggregated the information from a number of sources to provide a composite analysis for each conversion route. When in some places specific data (other than information already in the public domain) has been included in this report, the agreement of the company has been obtained. A copy of the questionnaire is provided in Appendix 2.

2.2 SCOPE

The project has focussed on technologies that have been developed at least as far as the construction and operation of a pilot plant, given the difficulties of establishing reliable costs and conversion efficiencies for earlier-stage technologies.

The project team contacted 89 companies active in developing projects and associated with a wide range of technologies and fuels and located in Europe, North and South America and Asia.

Table 1 shows the spread of these contacts between the relevant technologies.

Table 1. Number of contacts by pathway

Pathway	No of Contacts
Synthetic fuels via gasification	18
Pyrolysis and upgrading	9
HTL	3
Lignin to fuels	3
HVO and UCOME	7
Lignocellulosic ethanol via fermentation	14
Lignocellulosic ethanol by co-fermentation of starch	3
Fermentation and sugars to hydrocarbons	5
Alcohols to hydrocarbons	6
Biogas and biomethane	8
Other aviation fuels	2
Power to X	5
Other processes and contacts	6
Total	**89**

While some 38 companies provided responded to the requests for information, many companies were only able to confirm that the cost estimates of current production costs contained in the SGAB Cost Report were still relevant. Some data provided by companies was based on preliminary costs estimates which did not meet the minimum criteria of being based on pilot plant operation. This information was not taken into account in the study.

Relatively few companies were able to offer detailed insights into the future potential for cost reduction. The inputs from direct contact with companies were complemented by a number of recently published techno-economic studies for projects where relevant.

2.3 DATA ANALYSIS AND MODELLING

The data collected through the questionnaire described above has been supplemented with recently published data to update estimates of current costs of production of the fuels to be studied. For some less mature pathways there was insufficient detailed information available to allow a detailed analysis either from industry sources or from the literature.

Information from companies has also been used as the basis for estimating the medium-term cost reduction potential (i.e. within 10-15 years) from various routes to advanced biofuels. In many cases the information obtained was generic and not very detailed.

The longer-term potential for cost reduction (i.e. > 15 years) has been modelled by assuming that there is a significant expansion in production capacity, as required to meet low carbon scenario aspirations. The analysis considers the effects on cost of a range of learning rates, which have been experienced in other similar sectors, including conventional biofuels production.

2.4 BENCHMARKING COSTS

The projected costs of the fuels studied has been compared against the recent ranges of fossil fuel prices, along with those of some conventional biofuels such as bioethanol and biodiesel.

The projected future costs of the biofuels studied have also been compared with possible future fossil fuel price scenarios, using the fuel price assumptions incorporated within the IEA's World Energy Outlook (WEO) (IEA, 2018) scenarios, including the New Policy Scenario and the Sustainable Development Scenario (IEA, 2018). The analysis has also examined how some current biofuels support schemes are supporting the production and use of advanced biofuels, and how future carbon pricing regimes might impact the cost effectiveness of the studied fuels, using carbon costs cited in the IEA WEO scenarios.

3. Information on current costs of production

This section provides a summary of the estimated current costs of production of a range of advanced biofuels. This is either based on updated cost information provided by the companies we contacted, or on the information in the earlier SGAB Cost Report. Where new data has become available this is compared with the SGAB information to provide an update. Table 2 indicates the technologies covered, and whether updated information is provided.

Table 2. Technologies considered and status of information.

Technology Route	Update Information
Hydrotreated vegetable oil (HVO)	No
Biomethane from Anaerobic Digestion	No
Ethanol from lignocellulosic sugar via fermentation	Yes
Synthetic fuels via gasification (including biomethane, oxygenates such as methanol, ethanol and DME and synthetic long chain hydrocarbons such as FT diesel, gasoline or kerosene)	Yes
Pyrolysis oil and upgrading	Yes

There are many units that could be used to report cost data and production capacities. In order to deal with a wide range of fuels with different energy contents and bulk densities on a common basis, this report uses the same units as the earlier SGAB Cost report – i.e. production cost data is shown as EUR/MWh of product, and investment costs in EUR/kW of biofuels production output capacity. To facilitate comparisons with other studies, costs are also reported as EUR/GJ in the Executive Summary and Conclusions sections. An extended set of conversion factors is provided in Appendix 4.

For each production route, costs are broken down into three main categories:

- the contribution of capital costs to production costs;
- the feedstock costs per unit of production;

- other operating costs per unit of production

As a default, the capital charges are calculated using a finance cost of 10% and a project lifetime of 15 years (the sensitivity to the financing regime is discussed in Section 4). As a default, the cost calculations assume that plants can operate for 8,000 hours/year.

The costs of producing biofuels at a specific plant will be dependent on many local factors including the site costs and whether there is any appropriate infrastructure already in place. Feedstock costs will also depend on the availability and cost of local resources. Even when the technologies are mature there will therefore be a range of different production costs.

It should be emphasised that the resources available to this project only allowed a top-down approach, using numbers readily available from respondents or public sources. The analysis is therefore not based on a stringent and consistent techno-economic analysis based on detailed flowsheets and equipment lists to build-up estimates (although hopefully this has been done by the information sources). The respondents have not always given a break-down and even if such data was available for a sanity check, the data in this report has been amalgamated into one figure. Thus, it has not been possible to apply consistent costs for power, water, staffing costs, etc. There are also variations in the way individual organisations have provided the data. For example, in some cases the supply of hydrogen or oxygen has been treated as an operating cost, and in others specific process units have been included in the investment cost and utility and energy operating costs.

Given the aim of this project, the resources available and the availability of information, we have not attempted to derive plant specific costs, but to develop some broader cost estimates that allow us to judge in what range current and future costs lie and then how these compare with the costs of alternatives.

3.1 HVO

The Hydrotreated Vegetable Oil process (HVO) and Hydrotreated Esters and Fatty Acid (HEFA) processes converts raw materials such as such as free fatty acids or triglycerides (found, for example, in vegetable oils and animal fats) with hydrogen using catalysts under high pressure at temperatures between 300-400°C, followed by some degree of isomerisation and product separation by distillation. The main product is in the diesel fuel range, but kerosene and gasoline are also obtained in the process to a varying degree, depending on the process severity and degree of isomerisation. By-products are propane from the hydrogenation of the glycerol and light gases, as well as water and CO_2. The hydrogen can either be derived from the propane or be produced from natural gas or could come from electrolysis using electricity from fossil or renewable sources. The hydrogen production route would affect both the costs and overall GHG reductions achieved.

The scale of HVO units range from 0.05 to 1 million (metric) tonnes output. In 2017, some 5 million tonnes of HVO were produced globally. This figure is expected to increase to 6-7 million tonnes/year by 2020 and continue to increase thereafter. Some plants have been built specifically to produce HVO. In addition, some existing oil refineries have been converted to produce HVO or to allow co-processing of HVO with fossil streams in existing refineries. This leads to a wide range of specific investment costs.

The technology is mature. The main issue is the availability of sustainable feedstock, since the use of virgin vegetable oil feedstocks (notably palm oil) is increasingly unacceptable in many markets. Lipid wastes, including Used Cooking Oils (UCOs) and industrial wastes, are increasingly being collected and used as feedstocks. Oil crops which can be produced in ways with reduced risks of direct and indirect land-use change are being developed for large scale use in HVO production. These include brassica carinata, camelina etc. In the long-term, algae lipids could contribute additional feedstock. Production costs are shown in Table 3. They are dominated by the feedstock costs, which can make up 65-80% of the production costs. The cases reflect a range of situations from a refinery upgrade to allow co-processing, refinery revamps to HVO, and stand-alone self-supporting facilities.

The demand for HVO and industrial production capacity is expanding very rapidly and finding sufficient sustainable feedstock is likely to lead to cost increases and volatility, which will influence production costs.

Table 3. Indicative HVO production costs.

	Low	Medium	High
Investment costs (EUR/kW)	200	600	1,000
Feedstock cost (EUR/MWh)	40	60	60
Contribution to product costs - EUR/MWh product			
Capital	3	6	15
Feedstock	40	60	60
Other Operation & Maintenance (O&M)	8	12	16
Total	**51**	**78**	**91**

3.2 BIO-METHANE VIA ANAEROBIC DIGESTION

Anaerobic digestion (AD) technologies usually use a wet feedstock, although solid feedstocks (containing 30-35% dry matter content) are also increasingly used in so-called solid-state fermentation, especially for waste fractions. The feedstock is processed in a digester under anaerobic conditions at atmospheric pressure and temperatures slightly above ambient, in the range between 35°C and 60°C, and with a residence time of one to fifty days, depending on the substrate and temperature used. The product, biogas, contains methane (up to 50-70% by volume), CO_2 and some minor constituents/contaminants. To use the biogas as a transport fuel it is upgraded by removal of the CO_2 and the contaminants to reach 97% methane by volume. There is a variety of proven technologies for this purpose.

AD is a widely used process. In Europe alone there are 18,000 biogas plants. Over 95% are decentralised Combined Heat and Power plants (CHP) at small scale (average 0.5 MW_{el}). There were just over 500 plants where the biogas was upgraded to bio-methane in Europe in 2017. 200 of these were in Germany, almost 100 in the UK, and 65 plants in Sweden (Calderón, et al., 2019).

Processing via anaerobic digestion is done in smaller capacity plants (typically between 1-20 MW) compared to other biofuel technologies. Plants which upgrade biogas to biomethane are usually at the upper end of the capacity scale with 5-20 MW product output. Biomethane production amounted to 17 TWh in Europe 2017, but the total nameplate capacity is three times larger, i.e. an average of 12 MW per unit, with many plants operating below full capacity. The investment cost is of the order of 1,500-3,000 EUR/kW.

The annual operating cost is around 10-15% of the investment cost, with the main elements relating to the heat required for the process and the electricity used both in the biogas plant and in upgrading and compression. The Operational Expenditure cost (OPEX) depends heavily on the scale, since the staffing requirements are more or less independent of the capacity and can then become the dominant cost at smaller capacities. The choice of feedstock affects the value, or cost of disposal, of the digestate and has a strong influence on the overall economics.

There is a large variety of substrates available for biogas plants, including organic waste fractions, farm-yard manure, sludge from sewage treatment, food and meat processing industrial wastes. In addition, energy crops and straw can be used alone or in combination with other feedstocks. The feedstock cost can range widely from a negative cost up to 100 EUR/tonne for feedstocks such as straw. The biogas yield from the variety of substrates may in practice range from 150 Nm^3/tonne to 600 Nm^3/tonne of dry substance. The feedstock component of the production cost is a complex matter beyond the scope of this report, and the reader is referred to more specialised literature on this subject. For the purpose of this work the contribution of feedstock to the final product cost is estimated to range between -13 EUR/MWh and 50 EUR/MWh. Table 4 summarises the range of costs for production of biomethane by AD as cited in the SGAB cost report.

Table 4. Biomethane from AD - Production cost summary.

	Low	**High**
Investment costs (EUR/kW)	1,500	2,000
Contribution to product costs - EUR/MWh product		
Capital	25	33
Feedstock	-13	50
Other O&M	28	38
Total	40	120

3.3 ETHANOL FROM LIGNOCELLULOSIC SUGAR VIA FERMENTATION

Background

The production of ethanol from lignocellulosic materials by pre-treatment, enzymatic hydrolysis and fermentation is one of the most researched routes for the production of advanced biofuels, with some handful of commercial scale projects currently in operation, and several new plants currently being constructed and commissioned. These are summarised in Table 5.

Many different feedstocks are being used, depending on local availability. These include sugar cane bagasse and straw, cereal straws and corn stover and wood residues. A number of energy crops, including energy grasses, miscanthus and short rotation forestry crops could in principle also be used as feedstocks.

Table 5. Lignocellulosic ethanol plants – status.

Plant / Owner	Status*	Country	Capacity m³/year	Start-up Year	Comment
Raizen/ Cosan, Shell	O	Brazil	40,000	2015	Production not yet at full capacity
Bioflex 1/ GranBio	U	Brazil	82,000	2014	Redesigned - to be restarted 2019
Liberty/ Poet & DSM	O	USA	76,000	2015	Operational
Crescentino/ENI	O	Italy	50,000	2013	Sold by M&G to ENI in 2018
Kajaani/St1	O	Finland	10,000	2017	Cellunolix technology
Bargarh/ Bharat Petroleum	C	India	40,000	2021	Praj technology
Podari/Clariant	C	Romania	60,000	2020	Under construction
ABRPL refinery	C	India	60,000	2021	Formicobio technology
Bhatinda Plant/ HPCL	C	India	40,000	2020	DBT-ICT technology
Enviral	P	Slovakia	62,000	2022	Clariant technology. Investment not yet taken
Bina/ Bharat Petroleum	P	India	40,000	2023	DBT-ICT technology. Investment decision not yet taken
Raizen/ Cosan, Shell	O	Brazil	40,000	2015	Production not yet at full capacity

*** Key: O = In operation; U = Upgrade in progress; C = Under construction;**
P = Planning in progress

SGAB cost data

The SGAB cost report included an extensive analysis of the costs of fermentative ethanol production from cellulosic materials, based on information gained from a number of projects being operated in different world regions and using different feedstocks.

The capital cost of a production plant makes up a significant part of the overall costs. Considering a range of different plants, it was concluded that the capital costs lay in a range between 2,570 EUR/kW and 3,650 EUR/kW of ethanol production depending on various aspects e.g. plant size, technology complexity, evolution of the learning curve, and plant location.

Feedstock costs depend significantly on the type of material being used and whether it has to be specifically collected or produced, or if it is already on site (such as sugar cane bagasse). In the SGAB cost report, feedstock costs were considered to lie in a range of 10-20 EUR/MWh (50-100 EUR/dry tonne). With an energy conversion efficiency of 40%, feedstock adds between 25 EUR/MWh and 50 EUR/MWh to production costs.

The costs of enzymes also play a significant role in overall production costs. These costs have been significantly reduced - by about a factor of 10 since 2000 - through improving enzyme efficiency and better matching of enzymes to specific feedstock types. Enzyme costs were estimated at 15–

30 EUR/MWh of product. Other operating costs (which cover manpower, utility costs etc.) were estimated at between 13 EUR/MWh and 18 EUR/MWh. The overall range of production costs for cellulosic ethanol in the SGAB report is summarised in Table 6.

The Low case was included in the SGAB report to illustrate the importance capital and feedstock costs play in the overall production cost. Cost of capital is discussed separately in Section 4 of this report and the impact of feedstock price is discussed further below.

New Information

In the current study, only one new source of information has been added compared to the SGAB study. The overall production cost estimate from this new source lies within the upper half of the production cost interval in the SGAB table (Table 6). Feedback from industrial players has confirmed that the data in the SGAB report still provides a reasonable estimate of today´s spread of production costs.

In addition, new information was obtained on systems designed to integrate cellulosic ethanol production with "first generation" ethanol production from sugar and starch (corn grain). This can provide cost advantages through the potential to use materials already collected, and also to share some site facilities. The use of corn kernel fibre, a by-product produced in the production of ethanol from corn, provides one example, and the integration of ethanol production from sugar bagasse within sugar to ethanol production another.

Table 6. SGAB Cost Report: Costs of lignocellulosic ethanol production.

	Low	Medium	High
Investment costs (EUR/kW)	2,750	2,750	3,650
Feedstock cost (EUR/MWh)	10	13	20
Financing regime % /years	8 / 20	10 / 15	10 / 15
Contribution to product costs - EUR/MWh product			
Capital	32	42	60
Feedstock	25	33	50
Enzymes	15	15	30
Other O&M	13	13	18
Total	85	103	158

Corn fibre to cellulosic ethanol

A number of companies are developing technology which can use corn fibre produced as a coproduct in corn to ethanol production as a feedstock for cellulosic ethanol production. D3MAX LLC provided information to this study based on their first commercial plant design which is being commissioned by Ace Ethanol in Stanley, Wisconsin at their plant which produces about 190,000 m^3/year (50 million US gallons per year (MGY)) of fuel grade ethanol from corn.

The D3MAX plant at Stanley will be a full-scale commercial plant that will process 250 dry tons/day of wet cake into 14,000 m^3/year (3.7 MGY) of cellulosic ethanol, equivalent to 7% of the conventional plant capacity. The wet cake contains nearly all of the corn kernel fibre remaining after the starch fermentation in the dry mill ethanol plant. Construction of the facility at Ace Ethanol is underway and production is due to start in October 2019 (Yancey, 2019).

The technology uses the following processes:

- Feedstock preparation: The wet cake from a corn dry mill ethanol plant, containing nearly all of the corn kernel fibre after the starch fermentation is slightly diluted and treated with sulphuric acid.
- Enzymatic Hydrolysis, using cellulases and hemi-cellulases, supplied by DSM.
- Fermentation which occurs in the same tank as the enzymatic hydrolysis, using a yeast supplied by Lallemand Biofuels & Distilled Spirits.
- Ethanol Distillation and Dehydration.
- Stillage Processing which separates and dries the Distillers Dried Grains with Solubles (DDGS). The volume of DDGS produced is reduced by 25% but its crude protein content is increased from 30% to more than 45%.

D3MAX have costed two full scale commercial plants, one compatible with an ethanol plant producing 190,000 m^3/year (50 MGY) of ethanol from corn, and the other for a larger ethanol plant producing 380,000 m^3/year (100 MGY). After incorporating D3MAX technology they will produce 13,000 m^3/year and 26,000 m^3/year (3.5 MGY and 7.0 MGY) of cellulosic ethanol, respectively.

These costs have been used to produce a set of normalised production costs for comparison with the other processes studied in this section of the report, and using the same financing regime (i.e., financing at an 10% rate for 15 years of operation). The corn fibre "feedstock" would normally form part of the DDGS by-product that has value as a ruminant animal feed. During the process some of this material is converted to a lower fibre / higher protein product which has a higher value as a feed. In the calculation, the feedstock costs are taken as zero, and the calculation includes a credit due to the improved quality of the by-products.

The operating costs include provision for electricity and gas costs for feedstock drying. The costs are summarised in Table 7. This gives a total production cost range of 52-59 EUR/MWh of product.

Table 7. D3Max - Costs summary.

Plant scale	190 km^3/y (3.5 MGY)	380 km^3/y (7 MGY)
Capital cost, EUR/MWh	38	33
Feedstock cost, EUR/MWh	0	0
Operating costs, EUR/MWh	53	50
By product credit, EUR/MWh	-32	-32
Total	59	51

As might be expected, with a zero feedstock cost and the benefits associated with being integrated with a large-scale corn to ethanol plant, these costs are around 50% or less than those associated with a stand-alone plant. It is interesting to compare these data with those for “normal” cellulosic ethanol production as discussed above. In that case, the feedstock costs contribute 33-50 EUR to the final product cost.

The product is classified as “cellulosic ethanol” under the US Renewable Fuel Standard (RFS) and so qualifies for a higher premium than corn ethanol. There are about 200 corn dry mills ethanol plants in the US where such a plant could be replicated, typically adding 7% ethanol capacity to the mother plant. While there is further potential from corn fibre from wet mills, the technology has not so far been tested with such feedstocks. Replication potential outside of the USA and for other crops than corn depends on the local regulatory acceptance of genetically modified yeast used in the fermentation process, e.g. the DDGS produced would not be allowed as cattle feed in the EU.

3.4 SYNTHETIC FUELS VIA GASIFICATION

Background

Biofuel products which can be produced by thermal gasification and which are discussed in this section are:

- Biomethane.
- Oxygenates such as Methanol, Ethanol and Dimethyl Ether (DME).
- Synthetic long chain hydrocarbons such as Fischer-Tropsch (FT) Diesel, Gasoline or Kerosene.

Other products can be produced by the gasification of biomass including hydrogen and a mix of higher alcohols, but these are not further discussed here.

Gasification produces a synthesis gas (syngas) from a range of biomass feedstocks (woody biomass, waste, black liquor in pulp mills, agricultural residues, etc.). The gas can then be further processed to produce a range of products.

The main process steps are as follows. The fuel is pre-treated by drying and reduced in size to suit the particular gasification technology to be used. It is then fed to the gasifier, where it is converted to syngas, usually at elevated pressure and using pure oxygen and steam as the oxidant. The resulting raw syngas is conditioned and treated to remove impurities and carbon dioxide. The clean gas is then fed to a synthesis unit where the desired product is produced and then upgraded to marketable quality. Usually direct gasifiers are used. Entrained flow gasifiers are often used for liquid and pulverised fuels, and fluidised bed gasifiers are used for fuels with larger particle sizes like wood chips. To produce bio-methane, a low temperature, indirectly heated gasifier system may be preferred because it generates considerable amount of methane directly in the gasifier, and the oxygen plant investment can be avoided.

The overall conversion efficiency on an energy basis is the product of the individual conversion efficiencies of the four main process steps mentioned above. Overall energy conversion efficiency (from fuel as received to read- for-delivery product) is typically in the range of 40-65% on an energy basis (based on Low Heating Value - LHV). Efficient utilisation of by-products like steam and heat can increase the overall energy efficiency of the plant by up to 5-10%, when integrated with district heating or with combined heat and power production. There are some special biorefinery applications, such as gasification of black liquor in pulp mills, where the overall marginal conversion can reach around 70% and even higher when the black liquor is used for biofuels instead of for generating internal energy (steam/power).

The production of liquid hydrocarbons which can be used as drop-in replacements for fossil fuels, e.g. FT diesel and kerosene or gasoline, have the lowest yield from feedstock to product, and at the same time the highest specific investment costs. In contrast, the production of biomethane (and hydrogen) have higher overall conversion efficiency and relatively low investment. The difference in yield and specific investment cost between these two extremes is quite significant.

In the sections below the capital, fuel and operating costs cited in the SGAB report are summarised and then compared with more recent data found during this study, to produce updated cost ranges.

SGAB - Cost data for thermal processes

Production of alcohols and hydrocarbons from biomass and waste

The SGAB costs study evaluated the production costs associated with methane and methanol production provided by stakeholders and institutions involved in advanced technology development such as E.ON (200 MW output biomethane plant) (Moller, et al., 2013), VTT (200 MW output methanol plant) (Hannula & Kurkela, 2013) and CHEMREC (100 MW output methanol plant) (Landälv, 2017) and also data from public sources. The report indicated that the investment intensity was in the range of 1,850 EUR/kW to 2,050 EUR/kW for the two larger plants cited above. The SGAB report, taking account of other sou. rces, used specific capital costs for such plants in the region of 1,600 EUR/kW to 2,400 EUR/kW output

The energy conversion efficiency for biomass to methane and methanol is in the range of 60% to 70% (based on the feedstock lower heating value (LHV)at the plant gate). The efficiency for biomass to methanol processes is typically around 60% and some percentage points higher for methane producing processes. Conversion to methanol in pulp mills can be carried out with an efficiency of around 70%. Feedstock costs are typically 20 EUR/ MWh.

Other operating costs (covering staff, maintenance, utility costs including electric power as well as catalyst replacements and chemicals consumed etc.) typically contribute about 20% to the total cost of production (range 10-25%), corresponding to an annual cost equivalent to some 5-6% of the investment cost.

The SGAB report also considered the costs of production of ethanol and methanol from combustible materials derived from municipal solid wastes, where the economics are influenced by the low or negative feedstock costs. The review was based on information from Enerkem who have constructed a waste to methanol / ethanol plant in Edmonton, Canada (output ethanol approx. 30 MW). This plant uses assorted wastes as a feedstock. Capital costs were assessed at 120 MCAD (Atwell, 2016) while the waste separation and Refuse Derived Fuel (RDF) fuel preparation plant cost 40 MCAD (Lane, 2014) (City of Edmonton, 2014). The investment of 160 MCAD corresponded to approximately 105 MEUR. This gives an investment intensity of about 3,500 EUR/kW and a capital-related cost of production of 57 EUR/MWh. The gasification and synthesis part of the capital-related cost of production would amount to 43 EUR/MWh based on an investment intensity of 2,600 EUR/kW. Operations & Maintance (O&M) costs for the Enerkem plant can be approximately determined via relating the yearly cost of O&M to plant investment. 6% of investment as yearly O&M would give 26 EUR/MWh of product (based on full investment 105 MEUR).

FT Products

The SGAB cost report included cost information for the production of FT products, based on a large number of studies (Waldheim, 2017). The spread of data was considerable and no clear trend in terms of economy of scale could be seen. The analysis concentrated on a plant able to produce at a rate of around 200 MW. At this scale, analysis indicated an investment intensity of 3,000 EUR/kW. With the same capital charge as for the methane/methanol cases, the capital cost contribution to the production cost is 49 EUR/MWh. A spread of 750 EUR/kW leads to a range of 37-61 EUR/MWh.

The FT process is not a single product process, and a range of products is produced in significant quantities regardless of how the upgrading is designed. However, the process design severity can be optimised to some extent to suit particular market demands to generate either diesel and gasoline only, or to have also a significant fraction of Synthetic Paraffinic Kerosene (SPK) bio-kerosene to be used as aviation fuel, but with significant impacts on product yield and overall efficiency.

Given the differences associated with different gasification processes and upgrading steps, conversion efficiency can vary significantly, with the overall conversion efficiency from biomass to FT products ranging between 40-55%, depending on the feedstock, the gasification technology, the FT technology and notably the range of products produced. A feedstock price of 20 EUR/MWh will thus contribute with 36-50 EUR/MWh to the production cost of FT products.

Other operating costs contribute to about 15-25% to the total cost of production. Typically, these annual costs amount to some 5-10% of the investment cost.

To compare different data points while allowing for differences in the plant capacity, investment cost have in most cases been scaled to a common capacity of 200 MW product output by using a 0.7 exponential relationship. However, this assumes that technologies are generally scalable from the starting point capacity to 200 MW as single train units.

Scaling for OPEX has assumed that larger plant can be managed by more or less the same staff as smaller ones. Other costs have been based on a percentage of the investment cost, while consumables have been assumed to be a constant cost contribution per unit of product energy in MWh.

New Information

New or additional information on recent cost data has been obtained by contacts with some technology developers and suppliers, sometimes providing proprietary information or allowing access to studies and work later published and now cited in this report. This applies to Enerkem, Göteborg Energi (Thunman, et al., 2019), GTI (GTI, February 2019) and Karlsruhe Institute of Technology (KIT). Their respective inputs are gratefully acknowledged. In addition, publicised cost information for different plants and project in planning has been used to the extent that the publicised details on investments, capacities, fuel cost and usage, production capacity and operating costs have allowed. This applies to the Aemetis plant in Riverbank, California (Commercial Biofuels Digest, 2018), Fulcrum Biofuels, Lake Tahoe, Nevada (Lane, 2014), the GoGreen Gas plant (Anon., n.d.), Red Rock Biofuels plant in Lakeview (Anon., 2015), Oregon, TIGAS project (Process, 2015), Värmlandsmetanol (Anon., 2019) and W2C (Messenger, 2018) featuring the Enerkem technology.

An overview of the projects contributing new information is found in Table 8. Further information on the status and technical information on these and other projects can be found in a recent report (Landalv, et al., 2018).

Table 8. Overview of thermal projects contributing new cost information.

Project / Developer	Location	Technology	Fuel	Product	Capacity	Status
Aemetis	Riverbank, CA, USA	InEnTec Lanzatec	Orchard wastes, etc.	Ethanol	45,000 m^3 36 MW	Planning
Enerkem	Edmonton, AL, Canada	Enerkem	RDF	Ethanol (Methanol)	38,000 m^3 30 MW	Operation
W2C	Rotterdam, NL	Enerkem	RDF, (H2)	Methanol	278,000 m^3 152 MW	Planning
Enerkem 2G scale-up		Enerkem	RDF, (H2)	Ethanol		Planning
Red Rock biofuels	Lakeview, OR, USA	TGI, Velocys, EFI	Forestry and sawmill wastes	FT	57,000 m^3 71 MW	Construction
Fulcrum Biofuels	Lake Tahoe, NV, USA	TRI JM/BP	RDF	FT	40,000 m^3 50 MW	Construction
Värmlandsmeta nol	Hagfors, SE	TKI	Forestry wastes	Methanol	125,000 m^3 68 MW	Planning
GoGreenGas	Swindon, UK	APP AMEC FW	RDW	Bio-methane	66 MW 132 MW	Study
GTI	Stockton, CA, USA	GTI/Carbona HTAS	Orchard wastes etc.	Bio-methane	94 MW	Planning
GoBiGas	Gothenburg, SE	Repotec HTAS	Forestry wastes	Bio-methane	20 MW demo Various up to 500 MW	Idling - Study
KIT Bioliq		KIT/ AL CAC	Agricultur al residues	Gasoline	400 MW	Study
Tigas		GTI/ Carbona HTAS	Forestry wastes	Gasoline	215,000 m^3 242 MW	Study

As for the main question of this report, the potential for future cost reductions, little information was obtained directly from industry. When information was provided it did not relate to specific items but was more generic, for example suggesting that 10-20% cost reduction potential in both in investment and in operating costs might be possible. In the cited report on cost estimates for the GoBiGas plant, the authors did not consider any significant cost reductions due to learning effects when going from the demonstration plant to first generation commercial plants. This was justified by saying that all the units of equipment in the plant are already commercially available. However, the official final report has an entire appendix of 25 pages documenting experiences and lessons learned for each unit in the process.

Project and data analysis

The results have been analysed in two categories: plants producing alcohols (methanol, ethanol) and bio-methane, and plants producing hydrocarbons (FT fuels and bio-gasoline), respectively. In the original report only the FT process was considered. Now data from KIT Bioliq and TIGAS have been added, where methanol is produced first and then converted to DME or syngas is converted to DME directly, and then from DME to gasoline.

This post-processing of the initial product (FT crude via hydrocracking and isomerisation, and methanol to gasoline via DME) makes these processes more similar in terms of the type of analysis made in this report than direct conversion to the end product with a very limited post-processing in the case of alcohols and bio-methane.

It should be noted that these cost estimates mostly come from engineering studies or cost estimates for plants currently under construction or commissioning. It remains to be seen if the plants can be built and operated successfully, achieving the modelled plant availability (8,000 hours) and product quality over an extended period.

The Enerkem Rotterdam and scaled up plants have increased the specific yield of ethanol/methanol considerably, and therefore appear to have a very low specific investment cost, relative to the Edmonton and other facilities. However, this is mostly not related to improvements and developments of the gasification process. Instead these projects appear to be "hybrid" installations where external hydrogen is added to the synthesis gas. Since the Capital Expenditure (CAPEX) and OPEX, costs of the hydrogen used are not clearly taken into account, these projects are not comparable to the other data points. Likewise, according to the published data, the Red Rock Biofuels project seems to have an extremely high energy conversion efficiency from biomass to FT products, indicating that some other unknown element is at play, and therefore the public data is not comparable to other projects.

Several plants – for example those of Aemetis, GoBiGas, and GoGreenGas - are atmospheric gasifiers whereas most plants covered by the original SGAB work were pressurised. Since an atmospheric gasification plant cannot be scaled to 200 MW as a single train unit, some adjustments have been made to the specific investments to reflect this.

As in the case of gasification discussed above, little information specific information on cost reduction potential was obtained.

Review of production costs

The new information analysed during this study indicates that, while costs estimates have not changed radically since the earlier SGAB cost study, there has been some movement in estimates of capital and operating costs. In the case of alcohols and bio-methane, the cost figures indicate a 25% higher specific investment cost than in the SGAB report. This increase of the upper band can mostly be attributed to the fact that atmospheric gasifiers make up many of the new data points. This also affects the capital cost charges in the production cost.

The FT and gasoline plant specific investments fall within the range indicated in the SGAB report, where fuel costs were assumed to be between 10 EUR/MWh and 20 EUR/MWh for biomass fuel and a negative cost of -12.5 EUR/MWh for wastes. The range in biomass fuels reflected the information obtained for the lower costs of North and South America and the higher costs of the EU. However, it was noted that the projects in California cited in this work are based on very low biomass costs in the Central Valley, where the fuel cost at the gate is 5 EUR/MWh or less.

A gate fee of 12.5 EUR/MWh for wastes is not an extreme value. In the UK, gate fees of almost twice this value are being paid. On the other hand, the Fulcrum project has an integrated owner operated treatment and recycling plant that accepts municipal and enterprise wastes. The net of the gate fee, sales of recyclables and disposal costs of non-combustibles is said to allow a zero-fuel cost for the RDF used in the gasification plant.

While information on operating costs are only available from a few of the new sources for biomass feedstocks, it is noted that these costs are sometimes significantly higher than those used in the SGAB report, where estimates were typically based on an allowance of 5-6% of the investment cost annually. These costs may have been underestimated in the SGAB report- the higher numbers now are more like 9-10% of the investment cost annually. For waste gasification, the specific investment cost is also higher, and the lower percentage still seems reasonable as the absolute operating cost contribution, expressed in the EUR/MWh, is higher than that for biomass feedstock. This reflects the added cost for treatment of higher levels of contaminants in the feedstock together with disposal of ash and other secondary wastes.

As for other costs/credits, the only entry in the table reflects the fact that technologies producing liquid hydrocarbons generate tail gases that can be re-processed and re-used or be used to produce renewable electricity, so generating a credit.

The analysis also confirms the impact of using low cost waste-based fuels and the significant impact of these lower costs on the overall production costs of the fuels. The data shows clearly that producing biofuels or bio-methane from wastes is significantly cheaper than from biomass feedstocks. Capital costs are not significantly different for plants using the two different feedstocks, while operating costs for waste-based plants are higher, but this cost increase is more than offset by the negative feedstock costs.

It also shows that producing FT products or gasoline hydrocarbons is significantly more expensive, given the added process complexity and energy requirements. On the other hand, these products are compatible with the existing fossil fuel distribution system and vehicles.

Tables 9 and 10 and Figure 1 present updated ranges for the costs of production of biomethane and methanol and of FT liquids, respectively, based on this analysis. Considering the level of accuracy of the numbers and the influence of the conversion efficiency on the production cost, methanol and bio-methane have been considered as one group with a similar band of specific investments and conversion efficiencies and FT and other hydrocarbons as a second, separate group.

Table 9. Production cost of methanol and biomethane.

	SGAB Cost Report - Biomass		This work - Biomass		This work - Waste	
200 MW nominal biofuel output 8,000 hrs operation/year	Lo	Hi	Lo	Hi	Lo	Hi
Specific Capital cost EUR/kW product	1600	2400	2000	3000	2600	3600
Energy efficiency %	65	60	65	60	50	50
Feedstock cost EUR/MWh	20	20	10	20	-13	0
Contribution to product costs - EUR/MWh product						
Capital cost EUR/MWh	26	39	33	49	43	59
Feedstock cost EUR/MWh	31	33	15	33	-25	0
Operating costs EUR/MWh	13	18	14	30	30	30
Other costs/credits EUR/MWh	0	0	0	0	0	0
Total production cost	**70**	**91**	**62**	**112**	**48**	**89**

Table 10. Production cost of FT and gasoline hydrocarbons.

	SGAB Cost Report - Biomass		This work - Biomass		This work - Waste	
200 MW nominal biofuel output 8,000 hrs operation/year	Lo	Hi	Lo	Hi	Lo	Hi
Specific Capital cost EUR/kW product	2250	3700	2600	4500	2900	4500
Energy efficiency %	55	40	55	40	50	40
Fuel cost EUR/MWh	20	20	10	20	-12.5	0
Contribution to product costs - EUR/MWh product						
Capital Cost EUR/MWh	37	61	43	74	48	74
Feedstock cost	36	50	18	50	-25	0
Operating costs	13	18	14	30	30	30
Other costs/credits	0	0	0	-10	0	0
Total production cost	**86**	**129**	**75**	**144**	**53**	**104**

Figure 1. Summary of cost estimates for methanol and methane, FT products and gasoline hydrocarbons from thermal process chains.

3.5 PYROLYSIS OIL AND UPGRADING

Background

The technology for generating pyrolysis oil involves:

- pre-treatment - drying to low moisture content and milling to a particle size of a few millimetres (mm),
- pyrolysis in the reactor, which occurs at approx. 500 °C and a short residence time (of the order of a few seconds) and
- the recovery of the Pyrolysis Oil (PO) by cooling and condensation.

In addition, to arrive at a fungible transport biofuel, the pyrolysis oil must be upgraded.

In the pyrolysis process, combustible gases and unconverted biomass char are by-products, which are typically used in a CHP unit. The bio-char can also be sold as a product in its own right. The Pyrolysis Oil (PO) produced is a high oxygen, moderate water content and acidic solution that can be used as a combustion fuel. It is not miscible with fossil oils and cannot be used for engines without upgrading by hydrogenation to fuel components with similar properties to more conventional liquid fuels. The upgrading of the PO is a complex matter.

Mainly two direct routes for the upgrading, have been pursued:

- hydrogenation carried out as an integrated part of the pyrolysis plant facility, or
- off-site and then preferably in co-processing with fossil fuels in a fossil refinery.

The co-processing upgrading route can in principle be either by Fuel Catalytic Cracking (FCC) or by Hydrotreatment. The co-processing route has been explored in pilot tests in some refineries at a rate of a few % of PO blended in with fossil feed, mainly via the FCC route while the integrated route and hydrotreatment by co-processing have only been pursued at laboratory scale. The figures in Table 11 provide the indicative production costs for co-processing and for dedicated upgrading from the SGAB cost report.

Since the properties of straight PO make the upgrading by both co-processing and hydrotreatment difficult, there have also been a number of developments which aim to improve the intermediate product compared to straight PO. These include catalytic pyrolysis, where a catalyst is present in the pyrolyser. Alternatively, direct vapour phase upgrading of the PO downstream of the pyrolyser is carried out before condensation by suitable catalysts or some form of mild upgrading by e.g. hydrotreatment or other catalytic reactions of the straight PO after condensation. The aim of these procedures is not to arrive at a read-made fuel component, instead the purpose to improve the properties such as lowering the oxygen content, reduce acidity and eventually achieve miscibility with fossil feed fractions, thereby rendering the intermediate bio-oil to be more suitable for co-processing and allow higher blend percentages of compared to PO. Nevertheless, such developments are still at laboratory and bench scale such that data on economics is largely not available.

SGAB cost data

The figures in Table 11 provide the indicative production costs for co-processing and for dedicated upgrading from the SGAB cost report.

Table 11. Pyrolysis oil costs - co-processing and standalone upgrading.

	Co-processing		Standalone	
	Lo	Hi	Lo	Hi
Investment cost (EUR/kW)	2,250*	4,000*	2,340	2,340
Feedstock (EUR/MWh)	10	20	10	20
Contribution to product costs - EUR/MWh product				
Capital cost pyrolysis plant	39*	65*	38	38
Capital cost refinery	~ 1**	~ 1**		
Feedstock cost	34	68	15	30
Other O&M, Pyrolysis	~ net 0	~ net 0	29	59
Other O&M, refinery	~ 5*	~ 5*		
Total	79*	139*	82	127

* This number has been corrected for a calculation error in the original SGAB report.
** These figures are based on Rough Order of Magnitude (ROM) calculations. Data is generally not available and refineries are different in terms of their investment needs and processing capabilities such that a generic figure cannot be estimated.

Note: 1 EUR/MWh = 0.277 EUR/GJ = 0.265 EUR/MMBTU = 11.63 EUR/toe.

While the capital cost for the co-processing option is lower than for the stand-alone plant, the blend-in rate into the fossil streams in refineries with suitable technologies (Fuel Catalytic Cracking (FCC), Hydrotreatment etc.) is in practice limited to 2-10%, depending on the pre-processing of the pyrolysis oil intermediate, and the conversion efficiency is lower than in a standalone plant, the overall conversion efficiency from the feedstock to the hydrocarbon fuel was estimated in the SGAB cost report to 29%.

For the stand-alone case the study cited in the SGAB cost report indicate a biomass energy conversion efficiency, calculated as hydrocarbon fuel out to biomass energy of 68%, but in this case this does not include a substantial use of natural gas for the hydrogen production, this energy representing 12% of the biomass feed energy.

The estimated production cost ranges are 79-139 EUR/MWh for co-processing of biooil, and 82-127 EUR/MWh for standalone processing. Given the uncertainties in the costs a single range of 79-139 EUR/MWh is used in further analysis in this report.

3.6 SUMMARY - CURRENT COST ESTIMATES

Table 12 and Figures 2 and Figure 3 provide a summary of the estimates of the current costs of production from the technology options discussed above.

The costs of producing cellulosic ethanol are influenced strongly by feedstock costs and by conversion efficiency, but are estimated to lie in the range of 103–158 EUR/MWh. Producing ethanol from corn fibre is possible at lower costs given the reduced feedstock costs and the integration opportunities with the mainstream corn-to-ethanol plants, with costs estimated at 51-59 EUR/MWh.

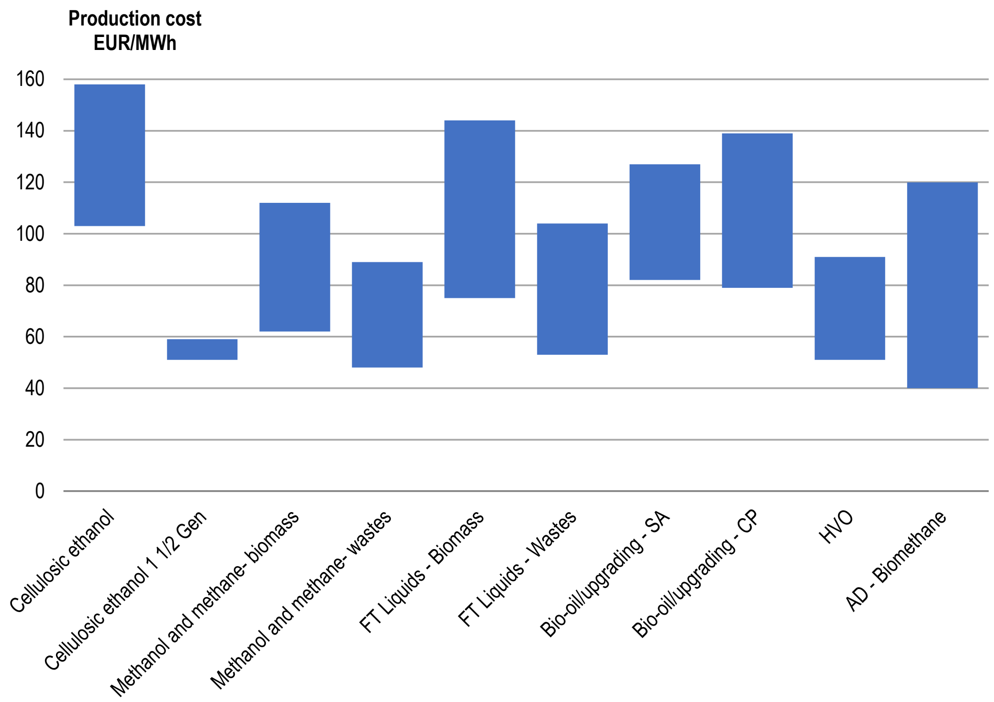
The production costs for methanol or biomethane produced by thermal routes, and FT or gasoline hydrocarbons fall in the range of 62-112 EUR/MWh and 75-144 EUR/MWh, respectively. Using waste as a feedstock at a gate fee of 0 or 12.5 EUR/MWh, the corresponding production cost falls in the range of 48-89 EUR/MWh and 53-104 EUR/MWh, respectively. The data shows that producing biofuels or biomethane from wastes is significantly cheaper than from biomass feedstocks. Although capital costs are not significantly different for plants using the two different types of feedstocks, the overall cost is influenced by the negative waste feedstock costs. It also shows that producing FT products or gasoline hydrocarbons are significantly more expensive than producing methane or methanol, given the added process complexity and energy requirements.

There is considerable uncertainty about the costs of producing and upgrading bio-oil and the relative benefits of stand-alone or coprocessing, but the range of costs is estimated at between 79 EUR/MWh and 139 EUR/MWh.

These cost estimates compare with those for the more mature HVO and Anaerobic Digestion technologies where the range if costs is estimated at 51-91 EUR/MWh and 40-120 EUR/MWh respectively.

Table 12. Summary of current production cost ranges.

	Costs, EUR/MWh				
Process		**Capital**	**Feedstock Costs**	**Operating Costs**	**Total**
Cellulosic ethanol	Low	42	33	28	103
	High	60	50	48	158
Cellulosic ethanol “1/2 Gen”	Low	33	0	18	51
	High	38	0	21	59
Methanol and methane-biomass	Low	33	15	14	62
	High	49	33	30	112
Methanol and methane - wastes	Low	43	-25	30	48
	High	59	0	30	89
FT Liquids – Biomass	Low	43	18	14	75
	High	74	50	20	144
FT Liquids – Wastes	Low	48	-25	30	53
	High	74	0	30	104
Bio-oil plus co- processing	Low	40	34	5	79
	High	66	68	5	139
Bio-oil stand alone	Low	38	15	29	82
	High	38	30	59	127
HVO	Low	3	40	8	51
	High	15	60	16	91
AD – Biomethane	Low	25	-13	28	40
	High	33	50	38	120



*** Note the data for cellulosic ethanol, 1½ generation assumes zero feedstock cost.**

Figure 2. Summary of current cost ranges.

Figure 3. Current cost ranges including cost breakdown.

4. Cost reduction potential

Many of the advanced biofuels technologies discussed here are still at relatively early stages of deployment and commercialisation, with only a handful of plants operating successfully at large commercial scale. There is therefore considerable scope for reducing costs. In the following discussion this is considered in two stages.

1) Where technologies are at an early stage of deployment, with only a few commercial plants built and operating, there is significant potential for cost reduction as a few successor plants are built, taking advantage of the experience gained in the first plants. The potential for such reductions has been identified in discussion with project developers and are associated with improvements due to continuing project optimisation, improvement through on-going R&D and in some cases by moving to larger scale plants to further benefit from scaling factors. There is also scope for cost improvement by improving the value obtained from by-products and improved integration with other processes. In addition, as the technologies become better established, the technical risks will be seen as less significant by project developers and financiers, and so capital for plants may become available on more favourable terms as confidence in the technologies grow. Taken together these reductions are referred to here as **"medium term cost reductions**" and could be realised within a 10-15-year time period if the necessary plants were built.

2) In addition, there is further potential for "**long-term cost reduction"**, due to continuing learning effects, such as have been experienced across a wide range of technologies and which are often described using learning curves. A massive increase in deployment of these technologies would be needed to reach the levels of contribution to global energy needs indicated in low carbon scenarios. Under these conditions significant experiential learning could be expected. However, the extent of these further cost reductions is more difficult to estimate with any precision as they will depend in a wide range of factors. In particular, such reductions will depend heavily on the rate of deployment of the various technologies. If attained, they would most likely be realised on a timescale beyond 15 years.

4.1 MEDIUM TERM COST REDUCTIONS

The technologies associated with the production of biomethane by anaerobic digestion and of HVO are now widely deployed and the scope for significant medium-term cost reduction, rather than progressive cost improvements, is considered to be limited. However, the other technologies discussed in Section 3 are still earlier in their progression to maturity, and so such reductions are considered possible, and are discussed in the next sub-sections.

Lignocellulosic ethanol

As part of this study, information on cost reduction potential was received from five cellulosic ethanol producers, and one research consultant - Clariant, St1, SEKAB, Borregaard, Praj, LUX Research. They considered the potential to:

- Reduce feedstock costs.
- Reduce plant capital costs.
- Reduce other operating costs and optimize co-product credits.

Reducing feedstock costs

The developers saw little potential for further reducing the costs of the feedstock they were using. While they felt that there could be potential to reduce costs by making their supply chain operations more efficient, these could be off-set by the need to move to higher priced feedstocks as demand for feedstocks grow. Optimal site selection – ensuring proximity to secure low-cost sources of raw material – is likely to be an important factor in decisions to build future plants. The important topic if feedstock availability and cost is discussed in more detail in Section 5.

Reducing capital costs

Developers indicated there was significant potential for reducing plant capital costs through a number of mechanisms. These include:

- Scaling up plant size (reduction potential around 20-30% of capital costs).
- Improvements and integration of process steps (for example by combining enzymatic hydrolysis and fermentation stages in a single unit, as well as increasing yields for the pre-treatment step).
- Integration with other processing facilities such as conventional ethanol production plants (for example, using sugar or corn as feedstocks) can lead to saving by using shared processes and infrastructure which are estimated at between 10% and 25% reduction of capital costs, although the potential savings will be dependent on site-specific details.

Taken together, developers expect such measures to enable a reduction of between 25% and 50% in the specific capital costs for a plant.

Reducing operating and maintenance costs

Plant developers expect to achieve significant cost reduction through enhancing plant performance, reducing costs and increasing coproduct values. Specific measures cited include:

- Increased enzyme activity and enhanced production yield per tonne of feedstock and integrated enzyme production.
- More efficient yeasts and higher conversion efficiencies.
- Performance enhancements gained through experiential learning which can lead to higher plant outputs (e.g. conventional ethanol plants can often operate at least 10% above the design capacity) and lower maintenance, utility and chemical costs.
- Enhanced value achieved for co-products (especially from lignin).
- Reducing maintenance requirements and costs.

It is anticipated that such measures can reduce operating costs by between 10% and 20% of current levels.

Overall medium-term cost reduction potential

The information from companies that provided data suggests capital costs could be reduced by some 25-50%, and operating costs by 10-20%, as discussed above. This information was mostly provided as cost reduction potential in percentage numbers without giving an indication of the baseline level. However, LUX Research, who also provided data for the SGAB report in 2016, has done both a cost comparison in relative and absolute terms. The data from this cost comparison was crosschecked with data supplied by plant owners and technology providers. Therefore, it is of interest to compare their data for 2018 and onwards with what they provided in 2016.

In a recent report, LUX reports updated data for two of the plants which were included in the earlier SGAB report. (Two of the other plants studied in the SGAB report have been shut down, and two more are focused on process optimisation activities, in one case because of a change in ownership).

The recent estimates provided by LUX Research are presented in Figure 4 below (LUX Research, 2018).

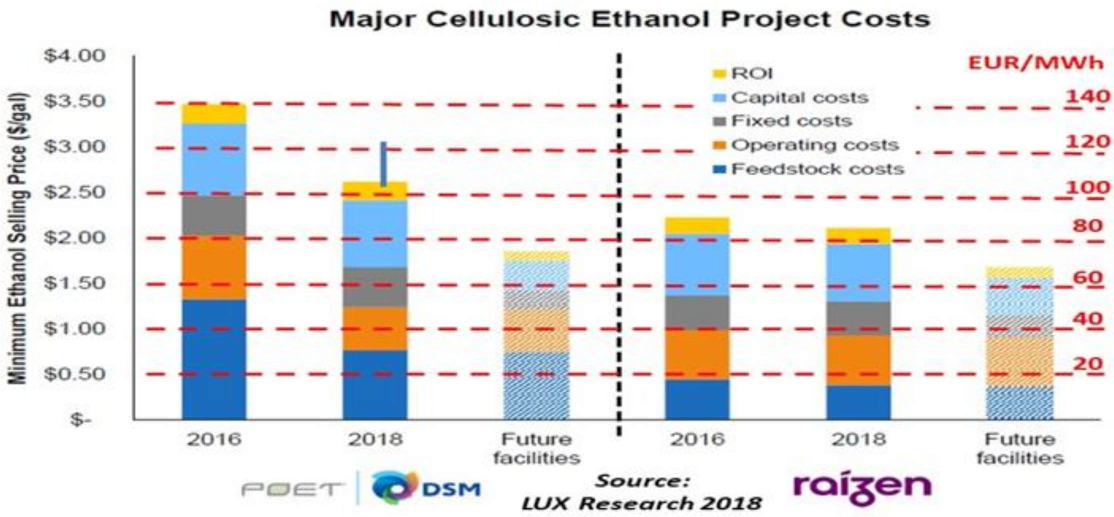


Figure 4. Cellulosic ethanol - recent estimates and potential for cost reduction - LUX Report.

Figure 4 shows a cost reduction between 2016 and 2018 and estimates a reduction for future plants. For the POET/DSM plant, LUX Research shows a decrease between 2016 and 2018 mainly due to reduced feedstock costs and partly due to lower operating cost. The cost reduction between 2016 and 2018 for the Raizen plant is small.

Lux estimates cost reduction potential for future plants at around 50% for the POET/DSM process, from about 140 EUR/MWh to 70-75 EUR/MWh, and at around 25% for the Raizen process, from about 90 EUR/MWh to 65-70 EUR/MWh.

The cost difference of around 10 EUR/MWh can almost entirely be contributed to cost of feedstock. From Figure 4, feedstock for the Raizen plant, which consists of the coproduct bagasse and by-product cane straw from a traditional sugar and ethanol plant, can be estimated to cost around 5 EUR/MWh if the energy conversion efficiency of the plant is assumed to be 33%. This compares to an estimated feedstock cost of 20 EUR/MWh provided by another supplier whose total cost of production is estimated to 100 EUR/MWh. POET/DSM and Raizen would have a similar production costs if their feedstock costs were the same, as the non-feedstock costs estimated to be about 50 EUR/MWh for both the plants.

One of the information providers also gave a future looking production cost estimate when including a number of cost-reducing potential circumstances listed above. Their list of assumptions included

- longer depreciation times,
- cheaper feedstock,

- use existing CHP plants,
- making use of the lignin and other by-products and creating another significant revenue stream from these,
- Catalytic Cracking Unit (CCU) & Carbon Capture and Storage (CCS) with incentives.

With these types of cost reducing circumstances in place they thought that it should be possible to reach a production cost of 70 EUR/MWh.

Table 13 show the specific reductions that have been applied to the capital and operating costs from the SGAB Report (still using a 10% finance rate over 15 years). Table 14 shows the results.

Table 13. Cost reduction assumptions for pessimistic and optimistic cases.

Plant scale	Pessimistic	Optimistic
Operating cost reduction	10%	20%
Capital cost reduction	25%	50%

Table 14 and Figure 5 show the impact of these reductions on the production costs.

Table 14. Potential costs of cellulosic ethanol production after reductions.

	Costs, EUR/MWh					
Process	**Low Cost Feedstock: 13 EUR/MWh**			**High Cost Feedstock: 20 EUR/MWh**		
	SGAB	Future Costs		SGAB	Future Costs	
		Pessimistic	Optimistic		Pessimistic	Optimistic
Investment cost EUR/kW output	(SGAB Low) 2,570	(SGAB-25%) 1,928	(SGAB-50%) 1,285	(SGAB High) 3,650	(SGAB-25%) 2,738	(SGAB-50%) 1,825
	Total production costs (EUR/MWh)					
Capital	42	32	21	60	45	30
Feedstock	33	33	33	50	50	50
Operating costs	28	25	22	48	27	24
Total	103	90	76	158	122	104

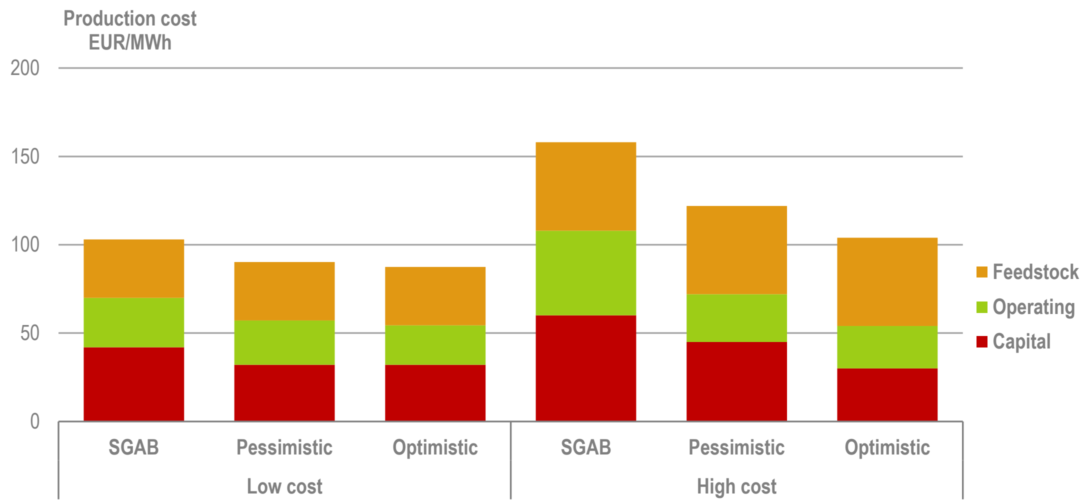


Figure 5. Cellulosic ethanol costs after potential medium - term reductions.

The overall impact of potential future cost reduction measures reduces the range of costs from 103-158 EUR/MWh (Landalv, et al., 2017) to 76 -122 EUR/MWh.

Table 15, shows the impact of applying similar a 25% reduction in capital cost and a 10% reduction to operating costs reductions to the cost data for the corn fibre-to-ethanol plant, reducing the overall cost range from 54-59 EUR/MWh to 41-47 EUR/MWh.

Table 15. Corn-fibre to ethanol production costs.

	Low cost		High cost	
	Current costs	Future costs	Current costs	Future costs
Capital	33	25	38	29
Feedstock	0	0	0	0
Operating costs	21	16	21	19
Total	54	41	59	47

Thermal routes to advanced biofuels

Developers were unable to provide the project team with such detailed estimates of the cost reduction potential for the thermal routes to produce advanced biofuels discussed above. Although these thermal biofuels routes are not yet widely deployed at scale, the unit operations associated with the thermal routes to advanced biofuels are also used in a range of other processes and so can be considered more mature than those associated with routes based on lignocellulose hydrolysis. The project team therefore considers that it is unlikely that medium-term cost reductions will reach the same levels as for cellulosic ethanol. Reductions in capital and operating costs of the range of 10-20% are felt to be achievable, resulting from a combination of scale-up effects on investments, staffing costs as well as efficiency improvements affecting both capital and operating costs of the range of 10-20% are felt to be achievable. These changes are reflected in Table 16 and illustrated in Figure 6.

Table 16. Potential costs of thermal biofuels production after reductions

	Methanol or methane biomass		Methanol or methane wastes		Biomass FT or gasoline		Waste FT or gasoline HCs		Bio-oil production and coprocessing	
	Lo	Hi	Lo	Hi	Lo	Hi	Lo	Hi	Lo	Hi
Capital cost EUR/MWh	21	44	34	53	34	59	38	67	36	59
Feedstock cost EUR/MWh output	15	31	-25	0	18	50	-25	0	34	68
Operating costs EUR/MWh	10	27	27	27	11	16	27	27	5	5
Total production cost	46	102	36	80	63	125	40	94	75	132

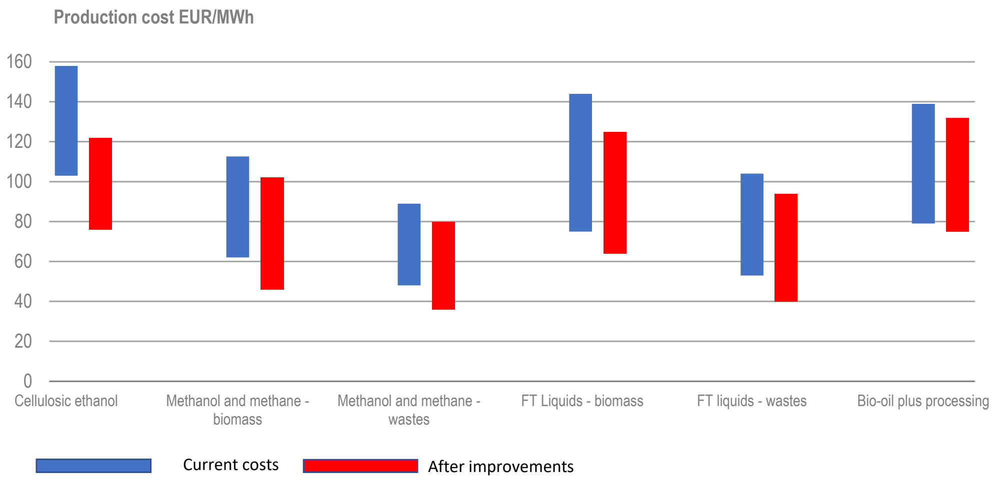


Figure 6. Impact of medium-term cost reductions on production costs.

Impact of feedstock cost and conversion efficiency

As noted above, feedstock cost plays an important role determining costs and access to low-cost feedstock will play an important role in future plant location, as discussed in more detail in Section 5 of this report. Energy conversion efficiency is also a critical factor. To illustrate the sensitivity of overall production costs to these factors, Figure 7 shows how the contribution to overall production costs from the feedstock element varies. This general analysis applies to all the conversion technologies. In addition, conversion efficiency also has impact on specific capital and O&M costs per unit of output.

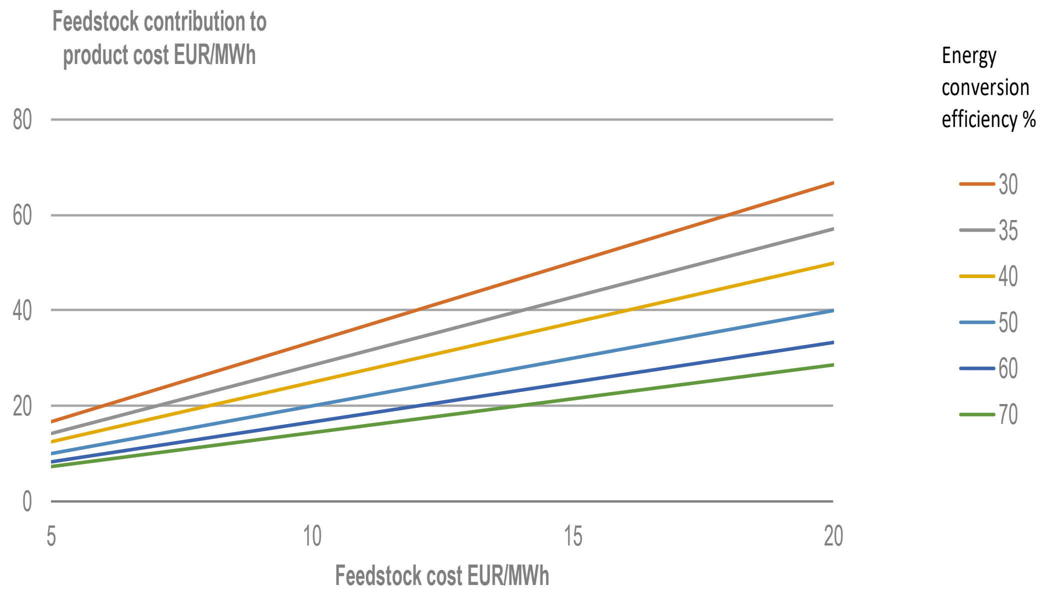


Figure 7. Cost of feedstock in the overall cost of production.

Improving financing rates

The availability and cost of finance for building plants will be a critical element in determining whether the deployment necessary to provide substantial quantities of advanced biofuels occurs. The availability and costs of finance will depend on overall economic and financial market conditions, but also on investor risk perception, taking into account the policy and market risks associated with securing a long-term profitable market for the products. Security of feedstock supply is another critical factor that influences the willingness of investors. Perceived technical risk is also a critical factor. The absence of a series of reference plants makes such investment unattractive to more conservative investors and pushes up finance costs.

As the technologies mature, the technical risks associated with projects will diminish. This will mean that it should be possible to reduce the financing costs associated with projects, assuming that all other risks are managed. If projects have a lower risk profile this should enable the overall cost of capital to be reduced in a number of ways – by reducing the rates of return needed by equity investors, by enabling a higher proportion of capital costs to be financed through loans, by increasing the length of loans, and by reducing interest rates. The impact of changing the financing rate and the financing period on the annual capital charge is shown in Figure 8.

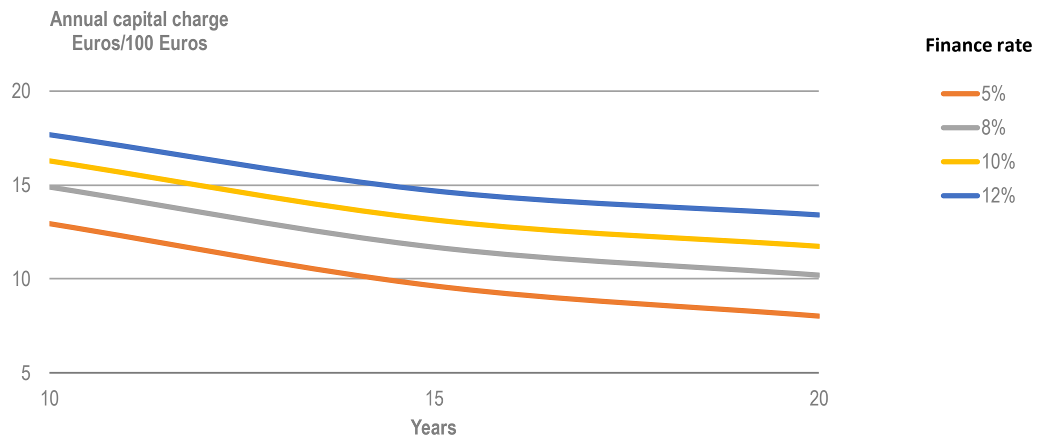


Figure 8. Effect of changing finance rate and term on annual capital charge.

Detailed modelling of the impact of all these financial parameters is outside the scope of this project. However, to illustrate the impact we have considered the impact of moving away from the default financing conditions used in this study – financing at 10% over 15 years. A lower cost of capital associated with a finance rate of 8% and a project lifetime of 20 years has been considered. The impact of this change is to reduce the annual capital charge for a given initial capital by some 22% (from 13.1% to 10.2%). The impacts of such a change on the range of production costs reported above are illustrated in Figure 9.

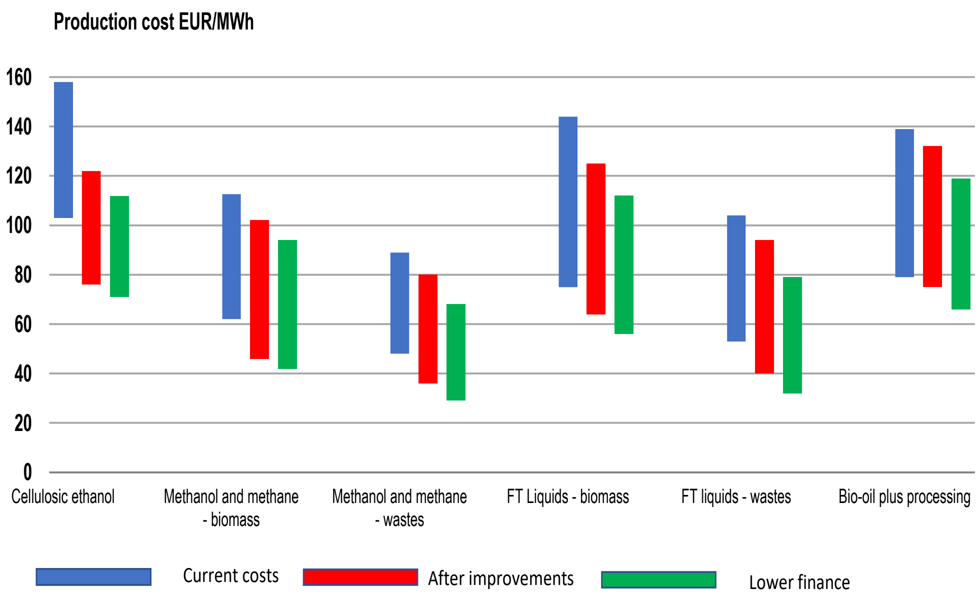


Figure 9. Impact of changing finance regime on costs.

Summary of medium-term cost reduction potential

Table 17 summarises the data on costs for the range of biofuels discussed above after the medium-term cost improvements and impacts of reduced finance costs are taken into account.

Table 17. Potential costs of biofuels production after reductions.

		Cellulosic ethanol	Methanol/ Methane Biomass	Methanol/ Methane Waste	FT Liquids - Biomass	FT Liquids Waste	Bio-oil	HVO	AD Methane
Current costs	Lo	103	62	48	75	53	79	51	40
	Hi	158	112	89	144	104	139	91	120
With process improvements	Lo	76	46	36	64	40	75	51	40
	Hi	122	102	80	125	94	132	91	120
Lower cost of capital	Lo	71	42	29	56	32	66	50	34
	Hi	112	94	68	112	79	119	88	113

The analysis indicates that based on the assumptions set out above, overall production costs could be reduced by between 5-27% through process improvements in the medium term. In addition, if increased experience makes it possible to finance plants on more favourable terms this will further reduce costs by some 5-16%. Taken together these measures can reduce the production costs range for biomass-based fuels to between 42 EUR/MWh and 119 EUR/MWh compared to current cost estimates of 62 EUR/MWh to 158 EUR/MWh, and for waste-based fuels to between 29 EUR/MWh and 79 EUR/MWh compared to 48 EUR/MWh and 104 EUR/MWh.

4.3 POTENTIAL FOR LONG TERM COST REDUCTION

The potential for longer term cost reduction is more uncertain, since it will depend on the extent to which the technologies are deployed and the scope for reduction in capital and operating costs, which may differ between the technologies since some (such as gasification) are based principally on unit operations which are already widely used in other chemical processes, whereas others may offer more scope for innovation. In addition, feedstock costs play an important role in the overall energy production costs, and there are uncertainties around the resource cost curves as demand rises. There will be a need to move to more expensive feedstocks and increasing opportunities to use feedstocks for energy production may lead to shortages and so push up prices, as discussed in Section 5. Nonetheless there will be potential to reduce technology costs further as discussed below.

Impact of learning-based cost curves for large-scale deployment

To reach the levels of deployment required in the long-term low carbon scenarios such as the IEA's 2DS will require a massive scale up in the number of plants using the technologies. The IEA Bioenergy Roadmap estimates the demand for advanced biofuels at some 25 EJ in the long term (by 2060). The output of a plant with a production capacity of 200 MW plant operating for 8,000 hrs/year is some 1.6 TWh or 5.76 PJ. To produce 1 EJ therefore requires some 174 plants, and to meet the 25 EJ goal means nearly 4,300 plants large scale plants would be required, producing the range of different products using the various technologies and feedstocks. To put this in context, there are currently around 1,600 ethanol plants and 650 biodiesel plants in operation worldwide, along with 20 HVO plants (Naumann, et al., 2019).

It is therefore worth considering what further impact large scale deployment might have on costs, over and above the relatively shorter-term gains discussed above.

Figure 10 shows how costs of production evolve as a process is developed and commercialised. Early estimates during the research and development phase usually prove overoptimistic, but once a commercial scale plant has been operated successfully, costs reduce as cumulative capacity grows as learning occurs, rapidly at first and then more slowly.

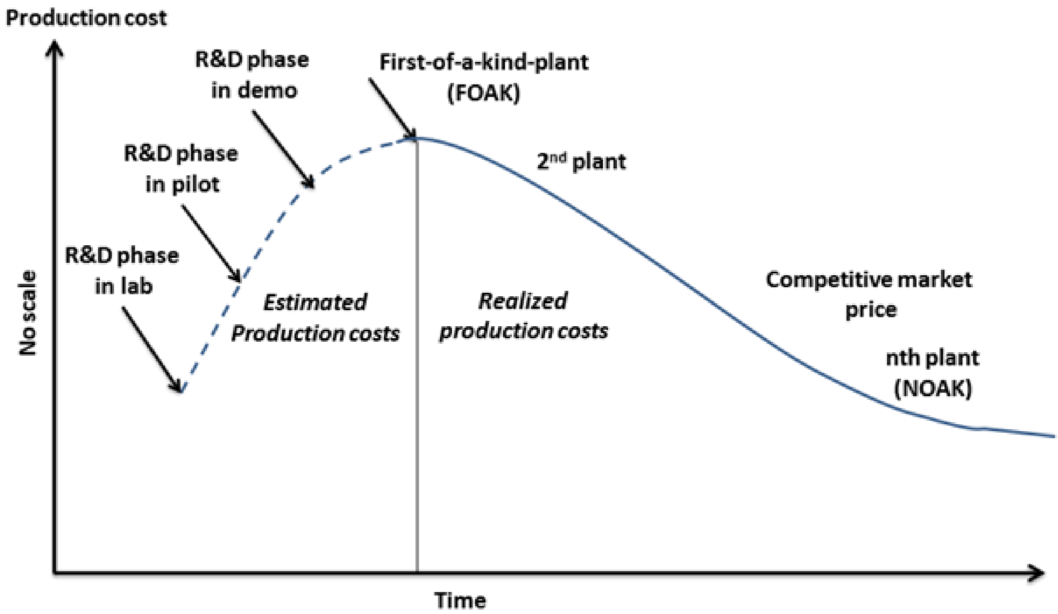


Figure 10. Illustration of the "learning effect" from innovation to industrialisation.

Empirical experience shows that the costs of a wide range of technologies have fallen as their cumulative capacity increases, with costs falling by a certain percentage (the "learning rate") for each doubling of cumulative capacity. As cumulative capacity grows, costs reduce logarithmically and more slowly on a linear basis as it is much harder to get the "next doubling". Such learning curves have been widely used to project cost reduction potential in many industrial processes (Anon., 2019), and apply across a very wide range of cumulative capacities.

Figure 11 shows the potential impact on costs of increasing cumulative capacity by factors of 10, 100 and 1,000 based on learning rates of 5%, 10%, 15% and 20%. Depending on the learning rate, costs fall by between 30% and 70% for a 100-fold scale up, and between 38% and 84% for a 1,000-fold increase in cumulative capacity.

Learning curves have been a good indicator of the scale of cost reduction for energy technologies like wind and solar PV. Reported observed learning rates range widely but for solar PV a rate of 21% has been observed (Anon., 2016). Learning curve effects have also been observed for cost reductions associated with bioethanol production over past decades. A rate of 20% is reported for Brazilian ethanol production (Daugaard, et al., 2015).

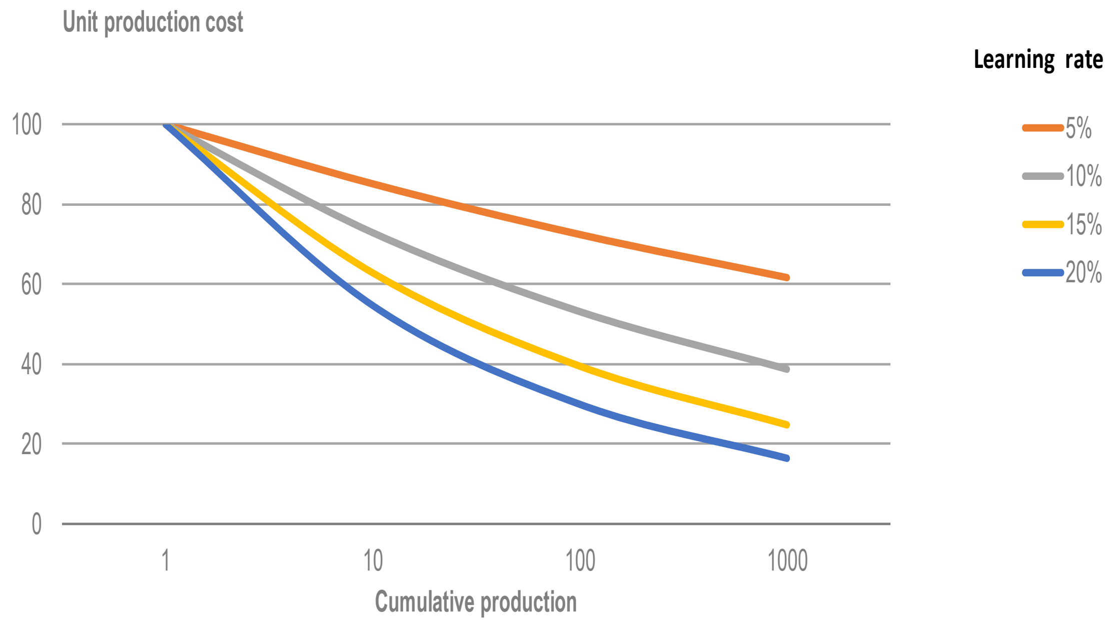


Figure 11. Impact of cumulative capacity increases on costs for different learning rates.

It is therefore reasonable to think that such learning effects will also apply to advanced biofuels projects, if and when significant capacity is developed, although it is difficult to predict what learning rate will apply. This may differ between the technologies since some (such as gasification) are based principally on unit operations which are already widely used in other chemical processes, whereas others may offer more scope for innovation. The scope for cost reduction for the better-established technologies (such as anaerobic digestion and HVO production) is more constrained given their widespread deployment and the limited scope for further scaling up by a factor of 100 or more.

To show the range of potential scale up impact, Figure 12 shows the impact of learning on the costs of the advanced biofuels considered above, for cumulative capacity increases by a factor of 10 and 100, and for a range of technology learning rates of 0-20%. The data assumes as a starting cost the estimate after the medium-term cost reductions have taken effect, taking a mid-point between the high and low-cost estimates shown in Table 17, and assuming that feedstock costs remain constant (shown as "0" learning " in the Figure).

As the figures show, depending on levels of deployment increase and of the learning rate achieved, experiential learning could lead to significant further reductions in costs, over and above those associated with the short-term cost reductions discussed earlier. The additional reductions could represent nearly 50% of costs, if high learning rates were achieved. However, determining the real scope for such cost reduction accurately is difficult as learning rates are uncertain

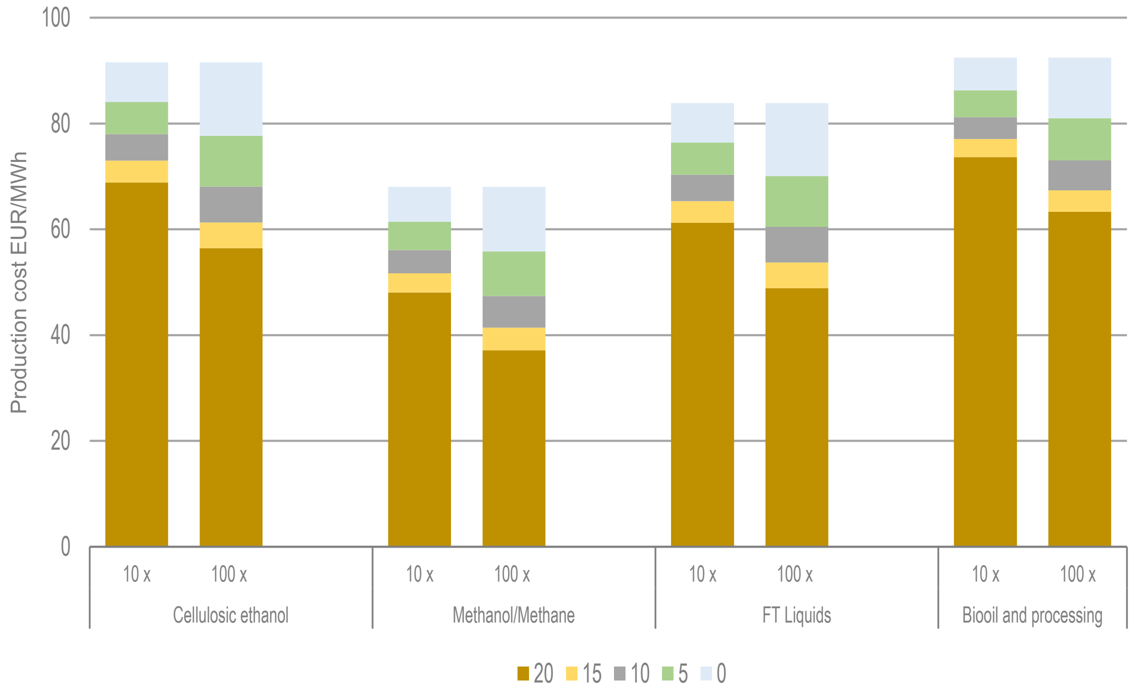


Figure 12. Impact of learning on costs with increasing learning rates.

4.4 COST REDUCTION - OVERALL SUMMARY AND CONCLUSIONS

The analysis above suggests very significant cost reduction potential for the fuels studied.

- In the medium-term cost reductions of 10-40% could be achieved through measures which industry could take, given the opportunity to build a portfolio of commercial scale plants. A further cost reduction of some 6-8% could be achieved if more favourable financing conditions could be attained.

- In the longer term there is potential for further significant reductions in capital and operating costs if there was very large-scale deployment of the technologies, but there is uncertainty over the likely extent of these longer-term reductions.

The analysis indicates that the less developed processes currently have higher costs than the more mature processes such as HVO, but also that they have the potential to become competitive with them if the medium-term cost reductions and the improved finance terms are taken into account.

The analysis also highlights the importance of feedstock availability and costs. There are wide differences between even similar feedstock costs within the projects examined, and lower and even negative feedstock costs associated with some waste-based fuels. As the capital and operating costs are reduced through the measures discussed, the feedstock costs will become a higher proportion of the total costs. Over time, the costs of feedstocks and the availability will therefore become an increasingly important factor in determining the affordability of advanced biofuels. These issues are therefore explored in the following section.

5. Feedstock – Costs and Availability

5.1 COSTS AND PRICES

Feedstocks produced from wastes and residues for conversion to advanced biofuels may be considered in four separate categories (IEA, 2012). These are:

- Wastes - materials which have no other useful purpose, and which otherwise have to be managed, usually incurring a cost.
- Processing residues and by products which arise part of an industrial process and are already available and pre-processed in quantity at a particular site (including for example sawdust to be used for pellet production or sugar bagasse).
- Locally collectable residues which are produced as part of a harvesting procedure, but which are dispersed, and which must be collected and brought to a central point and processed before they can be used, such as cereal straw, forestry residues or sugar cane straw.
- Internationally traded feedstocks, such as wood pellets, based on raw materials available at an industrial site, which are extensively processed to improve the energy density and then transported long distances to supply large scale conversion plants.

In addition, primary crops can be used as feedstocks. These can be crops grown principally to provide food, animal feed or other products which can also be used for energy production such as corn, sugar and vegetable, with prices determined by commodity markets. Such crops often provide both an energy feedstock and a valuable by-product such as DDGS or press cake for animal feed. Energy crops may also be produced as part of a rotation scheme, thereby not affecting the food and feed production of the same land, or by using low-intensity cropping on marginal land no longer in active use by farmers. In these cases, all the production, harvesting, and pre-treatment costs must be met by the off-taker.

Municipal Wastes

Disposal of waste materials such as municipal solid wastes poses an increasing environmental problem, especially in major cities, and is a major priority in rapidly growing economies such as China and India. Finding disposal solutions such as landfill become increasingly difficult and costly as volumes grow. Landfill is increasingly seen as environmentally unsustainable due to impacts such as methane emissions and impacts on water-courses. Solutions to minimise the problem include reducing waste generation, reusing and recycling materials and making use of some fractions of the waste as a feedstock, including for energy production through combustion and CHP production. The wastes are also being increasingly considered as a potential feedstock for biofuels production. The material in its raw form is very heterogeneous and significant pre-processing is needed to separate recyclable material (often required to reach recycling targets and related legislation) and to produce a refuse-derived fuel which has a more closely defined specification, which can then be used as a feedstock.

Using wastes such as the biogenic fraction of Municipal Solid Waste (MSW) as fuel or feedstock provides an alternative disposal or environmental treatment option that avoids disposal costs at a landfill. This environmental credit is often necessary to make energy projects economically viable, because the difficult characteristics of the feedstocks require specific technologies with high capital and operating costs, while the resulting fuel products are sold at general market prices.

The credit available for removing materials from the waste stream depends on the environmental legislation in place. For example, the EU has an objective to move away from landfilling a part of its waste management directive, and has set targets for countries to reduce the wastes sent to landfill. This has stimulated countries to act. For example, the UK has introduced a land-fill tax on materials sent for landfill, which has been increasingly steadily and now amounts to £91.35 (around 107 EUR) per tonne of waste. This acts as a strong incentive for other waste disposal methods which can offer a lower disposal cost. In other countries, landfilling of combustible or organic wastes is prohibited by law, and incineration is dis-incentivised by taxation, generating similar drivers. This means that waste can be available at a negative cost at the conversion plant in areas where waste management policies and regulation are pushing a move to alternative waste disposal methods.

Some waste materials can acquire a value once there is a profitable use for them. For example, Used Cooking Oil (UCO) and tallow have a traded market value when used for biodiesel or HVO production. If conversion capacity exceeds the local availability of material, then they acquire a scarcity value which can seriously affect the profitability of operation. Securing long term waste feedstock supply contracts therefore is often a prerequisite before such plants can be financed.

Processing residues

Many bio-based industrial processes lead to the collection and concentration of large volumes of residues at the point of production. For example: the timber processing produces large volumes of sawdust and other wood residues; pulp and paper production generates black liquor; the sugarcane industry produces large volumes of bagasse.

If there are no existing uses for these materials, or an excess once internal energy needs have been satisfied, they can be available at zero or low costs as the production and collection costs of such materials have already been occurred as part of the original process. However, such other economic uses are often possible and the materials acquire an "opportunity cost". For example, saw mill residues can be converted into wood pellets. Bagasse is the main source of energy for power and heat in the sugar mill, and is increasingly used for high efficiency co-generation resulting in grid-export of power. However, due to the use of mechanical harvesting increasing amounts of cane trash is becoming available as a fuel replacement for bagasse. Costs for use at the site where they are to be used typically range from zero to 15 EUR/MWh.

For process residues, the size of bioenergy plant operation may be limited by the availability of the raw materials, although this can be supplemented by bringing in additional materials available nearby in some cases, but increasing costs. (For example, bagasse in sugar mills is increasingly being complemented by cane straw residues that were otherwise left in the sugar fields).

Collectable residues

These are materials produced during harvesting operations in agriculture or forestry, that can be collected and brought to a central point for conversion into energy. Given the cost of collecting, transporting and eventually storing of the biomass, the costs of the delivered feedstock are increased since the collecting and transporting costs must be met by the user, with typical costs of 15-30 EUR/MWh. Increasing the catchment area pushes up the transport costs (and related CO_2 emissions) and will thus limit the economic scale of operation of such plants, with a catchment area usually limited to around 50 km radius.

However, as was noted in Section 4 in the discussion on gasification, some projects have cited even lower costs (5 EUR/MWh or less) for biomass residues such as orchard prunings in California, where alternative uses are difficult to find and open burning of the residues contributes to poor local air quality. Costs are therefore affected by local circumstances and significant deviations from the normal cost ranges can occur.

Internationally traded fuels

Finally, there is the prospect of pre-treating biomass to produce solid, liquid and gaseous feedstocks with high energy density, suitable for international long-distance shipping for use in large scale conversion plants. For example, wood pellets produced from sawmill residues, are currently produced in several regions including Russia, British Columbia and the Southern United States, and brought in bulk sea carriers to Europe for large scale power generation. Given the attractive incentives in several European countries, many European based utilities are actively developing supply chains all around the world. Currently such trade is motivated by incentives provided in European markets. Such fuels are compatible with the large scales of operation which provide for more efficient power generation. Larger plants will also be preferred for biofuels production in order to gain the economies of scale associated with larger conversion plants. Costs for such fuels may reach 30-45 EUR/MWh.

In the long run it is likely to be more economic to site conversion plants close to where large quantities of low-cost feedstocks are available and to transport the finished fuel products, which have higher energy densities and are easier to handle.

Prices and costs

The costs of some of these resources may be low, and early users of the materials as feedstocks may benefit from this in terms of the prices they pay to producers. However, once a market for the material starts to develop, and especially if there is potential for competition between users for material, then the materials may acquire a higher value and feedstock prices can become linked to product value (Naumann, et al., 2019).

For example, in Europe a number of plants were built designed to use post-consumer waste wood (from demolition sites etc.) to produce electricity. The financial investment case was based on the assumption that the developers would receive a gate fee for the materials which would otherwise have been sent to landfill. However, as capacity outstripped local supply, the wastes acquired a scarcity value and now command a positive price, undermining the profitability of the plants that have been built.

Developers tend to try and avoid such issues through careful siting of plants so that there is no competition for local resources, and by a long-term contracting strategy that locks in supply for an extended period. Companies also seek vertical integration of their supply chain, so as to be in control of more elements of the supply chain. For example, the bio-power group Drax in the UK have invested in wood pellet mills in the south of USA; Neste and other HVO companies have acquired UCO collection entities; UPM are developing energy crop supply chains in South America.

5.2 FEEDSTOCK AVAILABILITY

There have been many studies which have attempted to quantify the potential supply of biomass feedstocks for bioenergy use. The range of estimates varies by several orders of magnitude depending on the assumptions made. Key issues include the proportions of various wastes and resides that could be used economically while complying with sustainability requirements, and the estimates of how much land might be used to produce energy crops, given uncertainties around future food demand.

A review of the literature carried out as part of the work for the IEA Bioenergy Roadmap (IEA, 2017) estimated the potential long-term availability of biomass sources (to 2060), based on analysis of a wide range of studies at global level. The high-level results are summarised in Table 18.

Table 18. Summary of sustainable biomass resources. [3]

Source	Sustainability conditions	**Resources (EJ)** 2060
Municipal wastes	Taking account of the waste management hierarchy, which favours waste prevention and minimisation and recycling, and evolution of waste management systems in economies as they develop.	10-15
Agricultural wastes, residues and processing residues from wood and Agro-industry	Respecting the need to reserve some of the available resource for animal feed and to leave sufficient residues in the field for soil protection, and consistent with other uses.	46-95
Wood harvesting residues co-products	Used within the context of a sustainable forestry plan, which takes carbon aspects fully into account, along with measures to maintain other forest characteristics including biodiversity.	15-30
Agriculture	Produced on land in ways which do not threaten food availability and whose use leads to low land use change emissions, and subject to a positive assessment on other sustainability indicators such as biodiversity and water availability and quality.	60-100

The conclusions that can be drawn from this analysis are that:

- Despite the apparently better economics associated using MSW as a feedstock, global supplies are relatively limited and could not provide a substantial proportion of likely future biofuels needs. In many places waste incineration with energy recovery as power and possibly also heat may be preferred to using the material as a feedstock for biofuel production.
- Much larger supplies of wastes and residues from forestry and agriculture are likely to be available which could provide the bulk of the raw materials needed for advanced biofuels production.
- There is considerable scope for raw material supply from agriculture, with an emphasis on crops that can be co-produced with food crops or using contaminated or abandoned land so

[33] 1EJ equals about 278 TWh, about 25 Million tons of oil equivalent (toe).

as to avoid issues related to direct and indirect land-use change emissions.

There is still a need for more work to improve the knowledge of the likely availability of suitable feedstocks for advanced biofuels production and of their costs. Given the complex local considerations that influence likely availability and costs, such assessments are best carried out at national and regional level. Some examples of the results of such analysis are provided below.

Information at national and regional levels

There have been a number of detailed studies on the availability and costs of the resources that could be used as bioenergy feedstocks that can inform estimates of the likely global situation. Some of these are summarised below.

Biomass availability and costs in USA

In the US, the national availability and cost of biomass have been assessed by US Department of Energy (US DOE) in three studies known as Billion Ton Studies (2005 (Perlack, et al., 2005), 2011 (Perlack & Stokes, 2011) and 2016 (Langholtz, et al., 2016)). According to these studies, combined forestry resources, agricultural resources, wastes, and currently used biomass total 1.2 billion tons under the base-case scenario (which assumes a 1% annual increase in yield for agricultural and woody energy crop resources) and 1.5 billion tons under a high-yield scenario (which assumes 3% annual increase in yield). Resources available in the near term include agricultural residues, wastes, and forest resources. Energy crops shown are scarce in the near term, but are the greatest source of potential biomass in the future, contributing 411 million tons and 736 million tons in 2040 under the base-case and high-yield scenarios, respectively.

Table 19 summarises the production costs for potential supplies from forestry, wastes, and agricultural resources for the near- and long-term scenarios. The Table gives the farm-gate/roadside price - the total cost of production, harvesting, collection and storage at the roadside of farmland or forest stand, ready to be delivered to a processing facility. It also includes the amount that it is estimated could be supplied at different supply costs (including loading, transportation, unloading and pre-processing such as grinding). This analysis indicates that most of the US resource could be supplied at cost of between 12 EUR/MWh and 20 EUR/MWh, the upper feedstock price level used in the production cost analysis above.

EU – S2Biom Study

The S2Biom project supports the sustainable delivery of non-food biomass feedstock at local, regional and pan European level through developing strategies and roadmaps, informed by a computerised and easy to use toolset with updated harmonised datasets at local, regional, national and pan European level for the EU28, western Balkans, Turkey and Ukraine (FNR - Agency for renewable Resources, 2016). The study includes an estimate of the potential for biomass supply that could be made available while respecting strict sustainability criteria by 2030.

A first source of biomass relates to different types of agricultural residues that are currently underutilised. Estimates range from 186 Million tonnes to 252 Million tonnes in the 2030-time frame (3.2-4.3 EJ). The lower estimates put strong restrictions on collection of agricultural residues, e.g. for reasons related to protection of soil fertility, etc.

A second source of biomass relates to additional biomass from sustainable forestry. Estimates range from 615 million tonnes to 728 million tonnes ((10.5-12.4 EJ) in the 2030 timeframe (compared to an estimated current use of 530 million tonnes).

A third source of biomass relates to wastes (the lignocellulosic fraction after recovery and recycling; including paper waste, wood fraction of Municipal Solid Waste, cellulosic material in the form of unused food and garden waste, etc.), mainly deriving from households and businesses with previous estimates in the range of 110-150 million tonnes per year in EU for 2030 (between 1.0 and 1.5 EJ).

Table 19. Biomass availability and cost estimations for near term and long-term scenarios in the USA.

	Million dry tons (EJ)		
	Near term	Long-term, base-case	Long-term, high yield
Farm-gate/Roadside < 60 USD/Oven Dry Tonne (ODT) (11 EUR/MWh)	310 (5)	679 (12)	985 (17)
<84 USD/ Oven Dry Tonne (ODT) (15.5 EUR/MWh)	217 (4)	467 (8)	825 (14)
Delivered <=100 USD/ Oven Dry Tonne (ODT) (18.4 EUR/MWh)	217 (4)	564 (10)	825 (14)

A fourth major source of biomass relates to dedicated production of industrial crops on released agricultural land. Europe has unused land: some of this land is in this condition because of its inherent characteristics (difficult access, location, soil composition, climate), while other parts have once been profitable as farm land and are now abandoned as a result of overexploitation, pollution, climate change and/or exodus from rural areas. Working towards defining the potential of cropped biomass in such types of land is a key issue for short to medium term research. Estimates for the EU in 2030 are in the range of 84 million tonnes to 180 million tonnes of biomass while the respective figures for Western Balkans, Moldova and Ukraine add another 54-62 Million tonnes. So, in total the estimates for the production of industrial crops in EU28 & Energy Community are totalling a range of 138-242 million tonnes of fuel (2.3-4.1 EJ).

The overall figures for all four categories are in the range of 1.0-1.4 billion tonnes of biomass (between 17 and 22 EJ) which could technically be available within Europe by 2030 under sustainable practices. The estimated cost range is between 11 EUR/MWh and 18 EUR/MWh (roadside costs).

Brazil

Brazilian mills crushed 620 million tonnes of sugarcane during the 2018/2019 season. The South-South-eastern region of the country were responsible for 70% of the crushed amount, while the Centre-Western region accounted for another 22% (CONAB, 2019). The processing of sugarcane stalks yields large amounts of bagasse (around 180 million tonnes in 2018/2019, at 50% moisture content). These are largely employed in integrated Cogeneration of Heat and Power (CHP) units for the generation of both thermal and electrical energy to supply internal process requirements. In most cases, sugarcane mills are able to either export part of the produced electrical energy to the national grid or sell a small portion of surplus bagasse to the market. Besides sugarcane bagasse, sugarcane straw is also an abundant lignocellulosic material available for the bioenergy sector. Estimates point to an availability of some 43 million tonnes of sugarcane straw in Brazil (dry basis), considering a maximum recovery of 50% of the straw in the field – the recovery rate should be limited to allow a minimum amount of straw to remain in the field to protect the soil.

Brazil also has more than 7.5 million hectares of planted eucalyptus area. In 2017, 68 million m^3 of eucalyptus were destined to the paper and pulp industry, 39 million m^3 being used for energy purposes (around 240 PJ), and another 26 million m^3 employed for other purposes (Temer, et al., 2017). The estimated price of this resource is in the range of 46-64EUR/tonne.[4]

Table 20. Biomass selling prices in Brazil (Eur/tonne).

Feedstock	Region in Brazil	Average selling prices		Unit
		Market values	Model results	
Sugarcane stalks	Southeast	16 (2018/19) 17 (2017/18)	17 [b]	EUR/tonne (integral cane)
	Centre-West	-	16 [b]	EUR/tonne (integral cane)
Sugar cane bagasse	Southeast	Range: 14-55 [a] Average: 35 [a]	35	EUR/tonne (dry basis)
Sugar cane straw	Southeast	Range: 19-28 [a]	23	EUR/tonne (dry basis)
Eucalyptus	Centre-West	Range: 46-64 [a] Average: 56 [a]	59	EUR/tonne (wet basis)

[a] Obtained with the CanaSoft model of the Virtual Sugarcane Biorefinery (VSB), developed by CNPEM

[b] Retrieved from (Cardoso, et al., 2019).

5.3 CONCLUSIONS

The theoretical availability and cost modelling indicate that large volumes of feedstock could be made available to users at costs around 20 EUR/MWh. The costs of transporting the feedstocks and in some cases of additional pre -processing will depend in local circumstances. Delivered fuel costs of 20 EUR are already being seen in practice in some of the projects and design studies used for the costing. This suggests that feedstock costs may in practice exceed the theoretical estimates. More information from real projects is needed to test the costs of procuring suitable feedstock in the real world, and in particular to forecast the market when regional demand is growing very rapidly and

[4] Per wet tonne.

also affecting the suppliers in other regions, as has been the case for wood pellets.

There is scope for reducing the processing and logistical costs of collecting and using biomass feedstocks. For example, in Canada a 20-30% reduction in the cost of grinding forest resides at the roadside of forest stands has been reported (Friesen, 2018)

In 2010, The US Department of Energy, Bioenergy Technologies Office funded five projects known as high tonnage feedstock logistics projects which demonstrated significant cost reductions for collecting, storing, and transporting lignocellulosic biomass (US Department of Energy, 2014). Research is also underway to develop improved biomass/bioenergy crops that exhibit more favorable chemical compositions and are easier to convert to targeted biofuels. One example of alternative feedstock development is an effort to transform sugarcane and Miscanthus into better feedstocks for producing biodiesel and biojet fuels by engineering these plants to produce higher levels of oil (lipids) rather than sugar (carbohydrates).

National and regional assessments are very helpful in providing insights into likely long-term availability and costs of feedstocks for bioenergy production, including for the production of advanced biofuels. However, in order to be useful for estimating long term global availability such assessments need to be done in a very transparent way, with clear classification of the various resources and of the assumptions made in defining how much material could in practice be available, and around the sustainability considerations applied.

A useful step in harmonising such approaches would be the development of some best practice guidelines for such studies, including some standardisation and rationalisation of the classification of the various potential feedstocks, and of the sustainability constraints which are applied. Such measures could facilitate the development of more consistent resource estimates, which could be more easily complied to give a global estimate, at least for key producer and user regions.

6. Benchmarking costs

In this section the current and projected costs of the advanced biofuels considered are compared with those of "conventional biofuels" such as bioethanol and biodiesel, with a range of current prices for fossil fuel, and with longer term cost energy price projections. The need for financial support to "bridge the gap" between today's costs and those of fossil fuels is estimated.

6.1 CONVENTIONAL BIOFUELS PRICES

The costs of advanced biofuels can be compared with those of conventional biofuels such as starch/sugar-based ethanol and FAME-type biodiesel. US prices for both these fuels are reported by Iowa State University's CARD programme. The price of US ethanol is strongly linked to corn prices, but over the last five years has been between 1.2 USD/gallon and 1.6 USD/gallon (Iowa State University, 2019). This is equivalent to 47-54 EUR/MWh [5]. Prices in Rotterdam and Brazil are between 450-700 USD/m^3 and 300-600 USD/m^3 respectively (66-103 EUR/MWh and 44-88

[5] 1 m^3 ethanol is equivalent to 5.9 MWh.

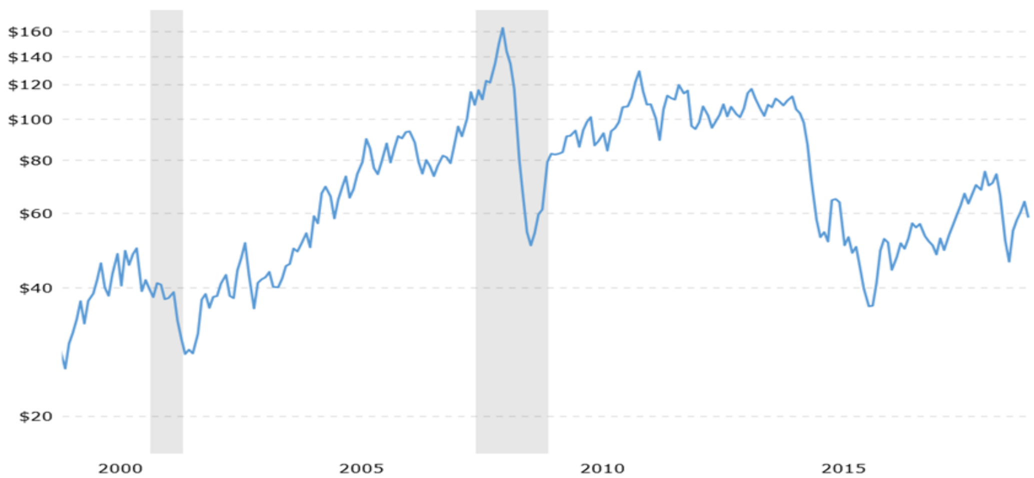
EUR/MWh) (Flach, et al., 2018).

According to the CARD programme data, US biodiesel prices, strongly linked to soya bean prices, have been between 2.8 USD/gallon and 3.5 USD/gallon, equivalent to 70-87 EUR/MWh (Iowa State University, 2019). European biodiesel prices have been in the range of 67-100 EUR/MWh (NESTE, 2019).

6.2 COMPARISON WITH FOSSIL FUEL PRICES

As Figure 13 shows, recently crude oil prices have been relatively low compared to historical levels with somewhat reduced demand and plentiful supply, including from the USA. This trend is expected to continue, although some price volatility is always to be expected due to short term supply and demand imbalances.

Global oil prices have ranged between 40 USD/bbl and 70 USD/bbl over the last five years, equivalent to between 22 USD/MWh and 40 USD/MWh. (19-30 EUR/MWh)[6]. Prices of gasoline and diesel fuels follow closely the trends in oil prices, but are on average some 35% higher than crude oil prices on an energy content basis as shown by Figure 14 (US Energy Information Administration, 2019).



Source: Macrotrends (https://www.macrotrends.net/)

Figure 13. Global crude oil prices 2000-2019. (USD/barrel)

These data suggest that it is appropriate to take a fossil fuel price range of 30-50 EUR/MWh as a current benchmark for the basket of fossil fuels for which advanced biofuels are being considered.

In considering the future costs of advanced biofuels, it is also important to assess the likely future price of fossil fuels. Oil prices are notoriously volatile so there is considerable uncertainty around such estimates, which will depend on the balance of oil supply and demand. In principle, moving to a low carbon scenario will constrain demand for oil and tend to reduce oil prices, but it will also

[6] Assuming 1.15 USD/EUR.

constrain oil exploration and development which will may increase oil prices.

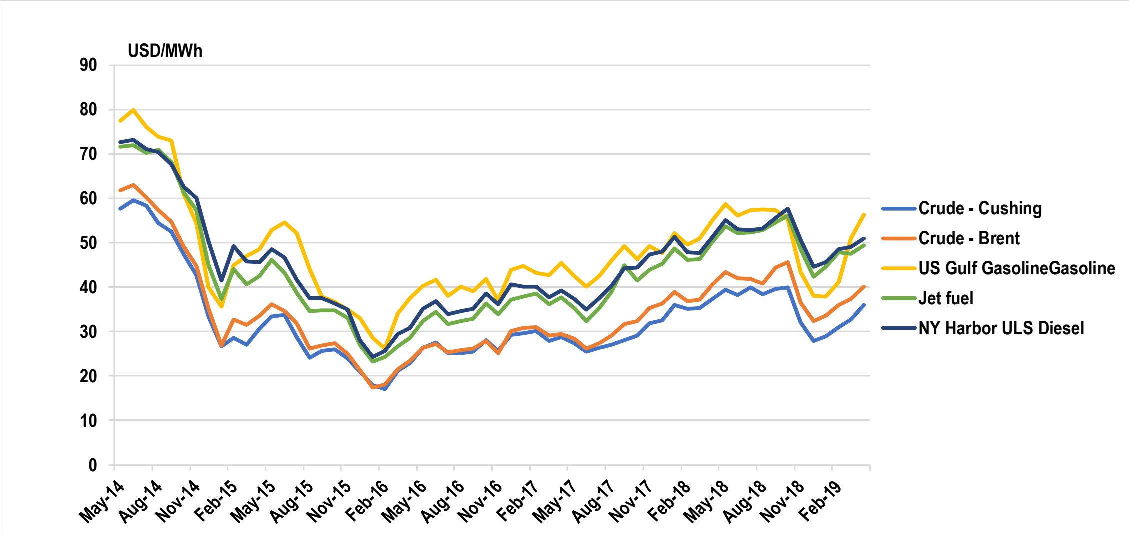


Figure 14. Variation in crude oil, gasoline, diesel and jet fuel prices on energy basis.

The IEA publishes oil price assumptions linked to each of its three principal scenarios in its World Energy Outlook (WEO). The three scenarios are:

- Current Policies Scenario (CPS)
- New Policies Scenario (NPS)
- Sustainable Development Scenario (SDS)

Figure 15 shows the oil costs assumptions from the 2018 version of the WEO (IEA, 2018).

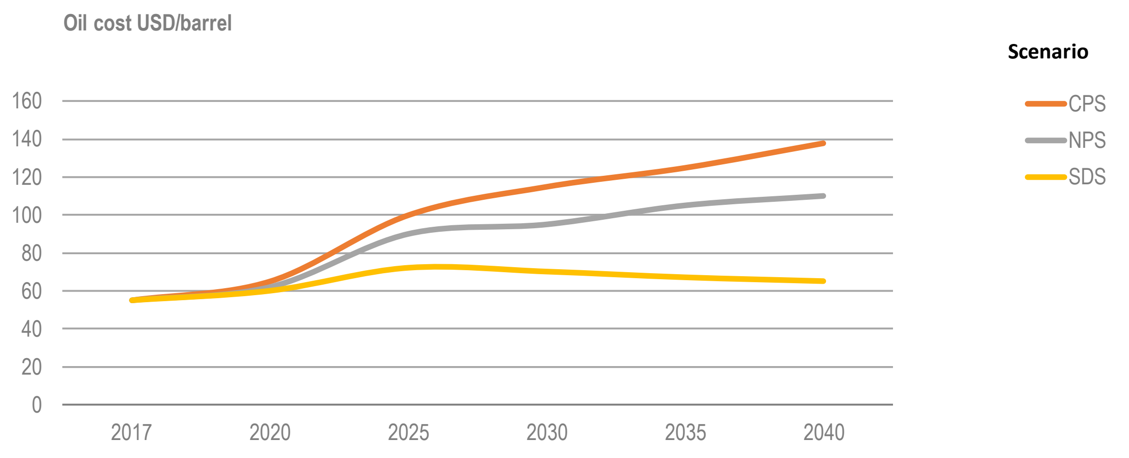


Figure 15. Oil cost assumptions in IEA WEO 2018.

In the CPS, oil demand is not significantly constrained, and oil prices rise to around 120-140 USD/bbl by 2030/40 (around 85-100 EUR/MWh for final product prices). In NPS, prices rise more slowly, reaching around 90-110 USD/bbl by 2030/40 (around 65-80 EUR/MWh). In the SDS demand is much more constrained and prices stay between 60-70 USD/bbl, close to today's levels but do not decline significantly. This range is equivalent to 40-50 EUR/MWh for final transport product prices.

6.3 BENCHMARKING ADVANCED BIOFUELS COSTS

Figure 16 compares the information on fossil and conventional biofuels prices above with the range of cost estimates for advanced biofuels made in Chapter 4, showing the current costs estimates along with those which might be achievable in the medium term, allowing for technical improvements and also a move to more favourable financing terms.

Figure 16. Comparison of advanced biofuels costs with current conventional biofuels and fossil fuel prices

The advanced biofuel options have the potential to be close to the recent range of prices for biodiesel and for bioethanol (67– 103 EUR/MWh and 44-103 EUR/MWh respectively) once initial deployment has geared up to allow process improvements to be affected.

Based on current costs, there is a significant gap between the costs of advanced (and conventional) biofuels and the fossil alternatives and although the gap can be narrowed by cost reductions in the medium term. The waste-based processes are an exception, as the analysis suggests that in cases where feedstock costs are low (i.e. the feedstock can be obtained at a significant negative cost) then these technologies have the potential to be close to cost competitive with fossil prices.

However, as discussed above, the opportunity to obtain waste-based feedstocks at these very low prices will be constrained by waste availability, competition with other uses (including the production of heat and power), and to regions where alternative disposal costs are high.

For the non-waste-based processes, the gap between their production costs and the likely range of fossil fuel prices is between 12-128 EUR/MWh, which the analysis suggests could fall to -8-89 EUR/MWh in the medium term, given market development. In the long term the cost gap could be further narrowed due to experiential learning, depending in what learning rate can be achieved and the availability of feedstocks at reasonable prices.

This gap could be bridged either by policy measures which provide additional revenue (such as that provided by certificate-based schemes). Alternatively, the gap could be closed by placing a carbon price on fossil fuels. Assuming that on average the use of fossil fuels in transport applications leads to emissions equivalent to 302 kg of CO_2 equivalent (kgCO_{2eq})/MWh[7], and that the biofuels solutions lead to an 80% reduction in emissions when life-cycle emissions are taken into account, then a 1 EUR/MWh cost gap between the fuel prices is equivalent to some 4.1 EUR/tonne CO_{2eq}. It would therefore need a carbon price in the range of 49-525 EUR/tonne CO_{2eq} to bridge the current gap, and this would be reduced to 0-365 EUR/tonne CO_{2eq} given sufficient market development in the medium term. With large scale deployment, experiential learning could significantly further reduce the necessary carbon price.

6.4 CARBON PRICE SCENARIOS

The IEA WEO gives scenario assumptions on carbon prices, as well as on oil prices. The scenarios assume that different carbon prices are applied in different countries and regions, reflecting differences in policy approaches. Table 21 indicates the range of carbon prices (in EUR/tonne of CO_2 equivalent (EUR/tonne CO_2eq)) within each scenario for 2040, with higher prices in the NPS and SDS scenarios (offsetting the lower oil price trends).

Table 21. Range of carbon prices EUR/tonne CO_2eq in IEA WEO Scenarios.

Scenario	C prices EUR/tonne CO_{2eq} - 2040	
CPS	0	34
NPS	17	38
SDS	109	122

As Figure 17 shows, the combined impact of crude oil price changes and carbon pricing associated with each scenario counteract each other and reduce the likely spread of future fossil transport fuel prices. Including carbon costs, the scenarios suggest that prices will lie in the range of 80-110

[7] Equivalent to 84 g/MJ. The RED II has increased this to 94 g/MJ

EUR/MWh, significantly higher levels than todays of 30-50 EUR/MWh.

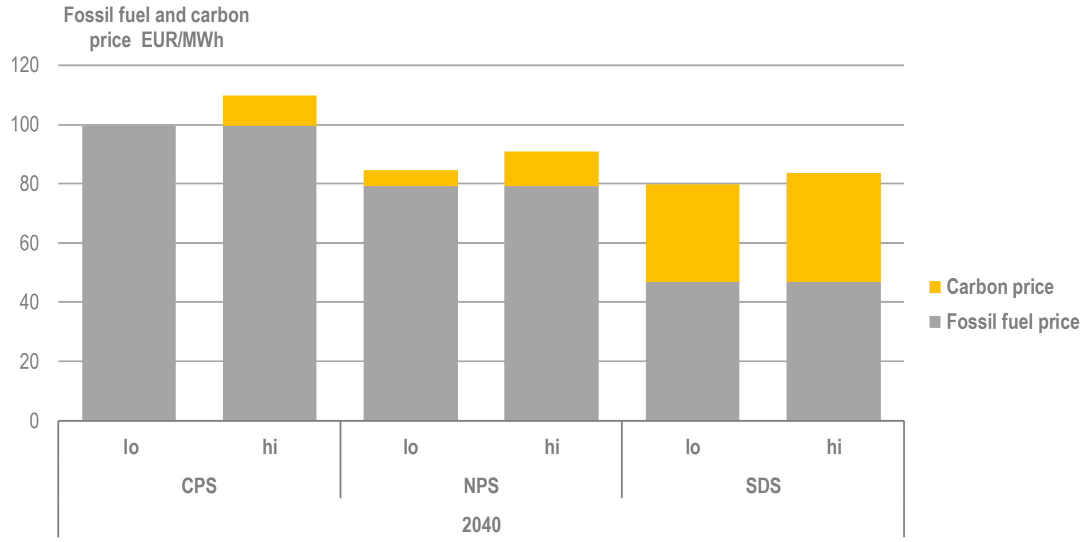


Figure 17. Fossil fuel and carbon prices in IEA Scenarios - 2040.

To show the range of potential scale up impact, Figure 18 compares these fossil fuel price projections with the estimates of advanced biofuels costs taking account of medium and long-term learning potential, as shown above in Figure 12.

The figure confirms that the advanced biofuels options will not be generally competitive with current oil prices even when the medium-term potential for cost reduction is taken into account. However, the figure also shows that advanced biofuels could be competitive in future if the potential combination of higher fossil and carbon prices projected in the IEA WEO scenarios are realised, especially if additional cost reductions due to experiential learning occur. Advanced biofuels therefore stand a good chance of playing an important role in the low-carbon transport fuels future. This will only happen if there is an enhanced level of policy support, so that their development and early deployment is facilitated, and if in the longer term the environmental costs of using fossil fuel are recognised, either though taxing fossil fuels or supporting the benefits associates with sustainable advanced biofuels.

6.5 BENCHMARKING – SUMMARY

The analysis above indicates that the advanced biofuels studied here are not currently cost competitive with the fossil fuels which they aim to replace. There is scope for considerable cost reduction in the short to medium term if a few generations of plants can be constructed and operated successfully, and the experience gained used to reduce costs and improve investor confidence. Even if that occurs there will in most cases be a continuing cost gap that needs to be bridged by policy support or the inclusion of external costs in fuel prices (except in the case of some waste-based plants which, when a significant "gate fee" is available, have the potential to approach cost competitiveness).

In the longer term, costs can reduce further if there is extensive deployment. Comparison with potential trends in fossil fuel prices and carbon pricing indicate that the technologies have the potential to become affordable in cases where a combination of fossil fuel prices and carbon prices rise significantly.

However, this future deployment will only happen if significant policy support is made available to help the technologies through the commercialisation and deployment journey, with support to off-set the risks associated with early stage projects, and significant continuing market support recognising the GHG and other benefits associated with the deployment of the technologies.

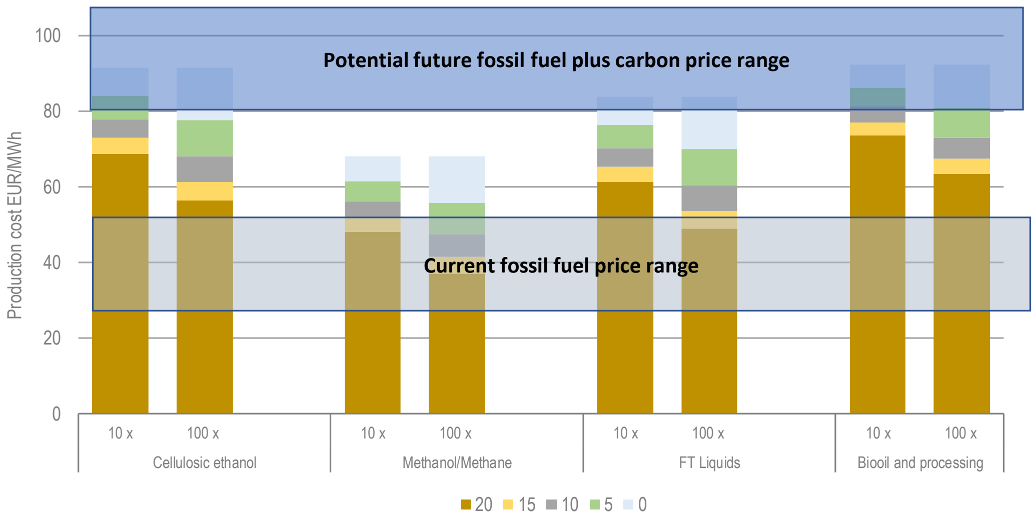


Figure 18. Impact of learning on costs of advanced biofuels, and projections for fossil fuel and carbon prices.

6.6 NON-FUEL COST ISSUES

While the costs of the advanced biofuels and other fuels discussed above are an important factor, a broader range of issues also need to be considered when comparing these options and when looking at other low-carbon issues such as electrification or using hydrogen as a fuel for transport or for other distributed uses, such as heating. These issues include:

- The extent to which they can directly replace fossil fuels, with biofuels which can be directly substitute for fossil fuels (such as bio-jet fuels and other drop in fuels) having advantages over fuels which can only be used in blends or with significant modifications to end-user equipment such as vehicles;
- The costs of any modifications or of distribution costs associated with fuels, such as the need for separate distribution infrastructure.
- The likely availability of feedstocks; for example, waste feedstocks have benefits in terms of likely costs, but such feedstocks will not be available in sufficient quantities to match likely biofuels demand;
- The life-cycle GHG emissions associated with particular routes.

The overall consideration of the future for the advanced biofuels need to be seen in the context of these other factors, and based on an analysis of full system costs, feedstock availability and life-cycle GHG emissions.

7. Policy support

7.1 CURRENT POLICY SUPPORT

The steady growth of biofuels production and use has been supported by biofuels policies. These policies take many forms, including blending mandates, excise tax reductions and exemptions, renewable or low carbon fuel standards, fiscal incentives and public financing. These measures can be applied at different stages of the biofuels production and consumption chain. Technology neutral market-pull instruments including biofuels blending mandates have been broadly effective to support technologies that are relatively mature, as they create a demand for biofuels, which is typically met with commercial conversion technologies such as conventional ethanol or biodiesel. However, such policy instruments on their own can be limited in their capacity to pull early-stage technologies into the market, are typically more expensive than conventional biofuels and fossil fuels as illustrated by the analysis in this report.

Recognising the benefits in terms of improved GHG performance and the ability to use a wide range of residue-based feedstocks, a number of policy initiatives are under way, in North America, Europe and Brazil which aim to help advanced biofuels take their place in the market. Some examples are discussed briefly here.

7.2 POLICY SUPPORT MECHANISMS FOR ADVANCED BIOFUELS IN US

The US Renewable Fuels Standard (RFS) and the California Low Carbon Fuel Standard (LCFS) and are examples of market-pull policies that aim to pull second generation biofuels into the market either by setting volumetric mandates for advanced biofuels (in the US RFS) and by providing a fuel agnostic incentive to transportation fuels with lowest carbon intensity (California LCFS). Under both programs, credits are available for qualifying biofuels which increase the market value of the biofuels and make them economically viable at certain times, especially when the credit prices are high. However, these two policies have different approaches to propel the production and consumption of advanced biofuels. The policies are described in Appendix 1.

To illustrate the impact of the policies Figure 19 shows the market value of cellulosic ethanol in California at certain times in 2016 and 2018.

As shown in this figure, the market value of cellulosic ethanol was 3.74 USD/gallon and 4.33 USD/gallon in 2016 and 2018, respectively. This is equivalent to 147 and 170 EUR/MWh respectively. About 60% of these market values are policy driven (Renewable Identification Numbers or RINs and LCFS premium). This is significantly higher than the current production estimates of 103-120 EUR/tonne noted earlier in this report. The current credit within the RFS and LCFS for cellulosic ethanol is equivalent to 455 EUR/tonne CO_{2eq} (529 USD/MT CO_{2eq}).

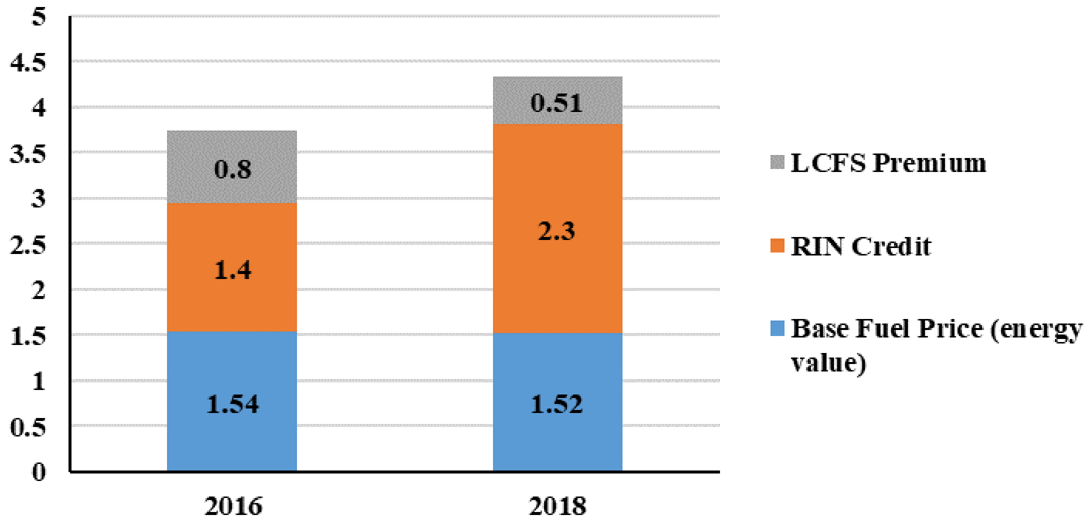


Figure 19. The market value of cellulosic ethanol in California in 2016 and 2018 (USD/gallon).

As Figure 20 illustrates, the LCFS is proving successful in increasing a range of low carbon alternatives in California, with a 60% increase in the use of alternative fuels in California between 2011 and 201 (shown as millions of US gallons of gasoline equivalent).

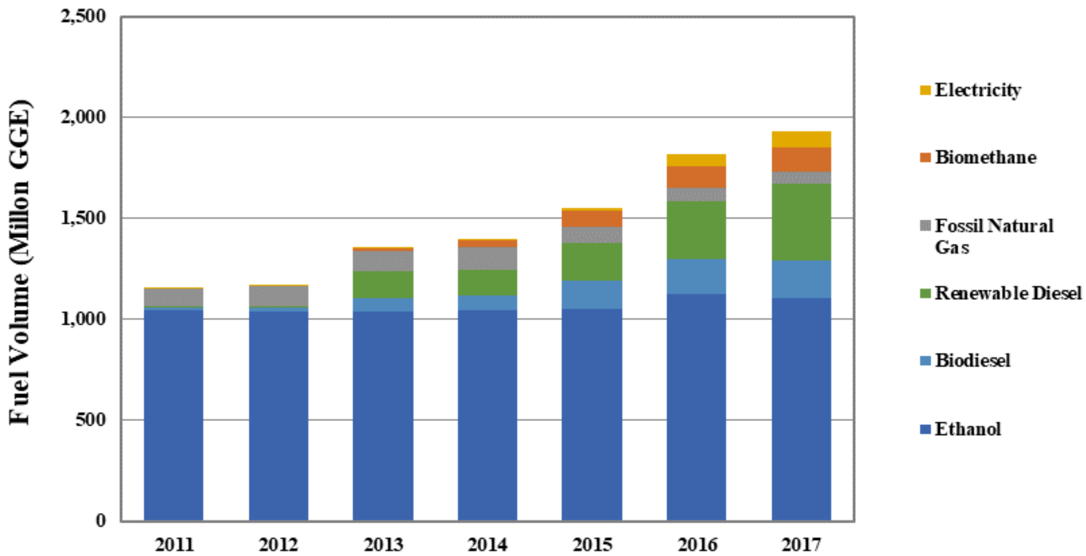


Figure 20. Increase in alternative fuels in California 2011 - 2017.

7.3 EUROPEAN UNION - THE RENEWABLE ENERGY DIRECTIVE (RED)[8]

RED

The primary source of EU legislation currently in force regarding biofuels is the RED (2009/28/EC, 2009), agreed in 2009. This establishes an overall policy for the production and promotion of energy from renewable sources in the EU and establishes an overall target to produce 20% of energy from renewables by 2020. Under RED, EU Member States are required to obtain a share of energy from renewable sources in all forms of transport of at least 10% by 2020. In order to be counted towards the target biofuels must meet certain sustainability criteria, irrespective of whether they were produced using raw materials cultivated inside or outside the EU.

The proportion of the target which can come from biofuels produced crops grown on agricultural land is limited to 7%. This limit was introduced in 2015 to address concerns related to Indirect Land Use Change (ILUC). Advanced biofuels fall outside the 7% limit as well as biofuels produced from used cooking oil and animal fats. There is an indicative target of 0.5% for advanced biofuels, and advanced biofuels, as well as biofuels produced from used cooking oil and animal fats, are double counted towards the 10% target.

A revised RED-II (2018/2001 EU Directive, 2018) was adopted on of 11 December 2018 and the Member States will have to transpose the RED-II by 30 June 2021 and the original RED will be repealed as from 1 July 2021. The RED-II sets a binding overall target to ensure that the share of energy from renewable sources in 2030 is at least 32%. Member states do not have mandatory individual targets for their overall renewables' contribution

Under RED-II, Member States have to require fuel suppliers to ensure that the share of renewable energy supplied for final consumption in the transport sector is at least 14% by 2030. This share is calculated as the sum of all biofuels (subject to fulfilling the sustainability and GHG emissions saving criteria set out in the directive) and renewable transport fuels of non-biological origin used in the transport sector. However, biofuels from oil, sugar and starch crops are limited to 7%, or to 1% higher than the level of use of such biofuels in the member state in 2020 (whichever is lower).

The RED-II defines advanced biofuels as biofuels that are produced from feedstocks listed in Part A of Annex IX of the directive (See below). It provides that biofuels and biogas produced from these feedstocks shall equal to at least 0.2% in 2022, 1% in 2025 and 3.5% in 2030, gradually increasing their share over time. Furthermore, the contribution of advanced biofuels will be double-counted towards the 14% target. The Commission can add feedstocks to Part A of Annex IX, but only those that can only be processed with advanced technologies. There is also a limitation for waste lipid-based fuels (Part B of Annex IX) to 1.7 %, but these are also double counted.

Member State Measures

Member states are responsible for putting in place measures to give effect to the requirements of the RED, and are using a variety of different mechanisms. Some examples are provided below (Giuntoli, 2018).

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[8] Extracts from ART Fuels Forum, Advance Biofuels in India: A comparative analysis between India and the EU for cooperation and investment, Final Report, Radhika Singh, Stamatis Kalligeros & Jai Uppal, October 2018.

Denmark

In 2009, Denmark implemented a biofuel mandate for road and rail transportation fuels which was increased to 5.75%, which is still the current level of the mandate. Biofuels consumed in Denmark are exclusively conventional biofuels, principally biodiesel (80% of all biofuels), followed by ethanol and a small share of biomethane. Denmark transposed the EU ILUC Directive in 2016, introducing a 0.9% mandate for advanced biofuels starting in 2020.

The mechanisms for Denmark's support for biofuels are tax exemptions and direct subsidies. Since 1992, Denmark has imposed a carbon tax on fossil GHG emissions. The value of the carbon tax in 2018 was equal to 173 DKK per ton CO_{2eq} (ca. 23.2 EUR per ton CO_{2eq}). Liquid biofuels are exempted from this carbon tax as well as other energy taxes.

Germany

Germany has had a biofuel mandate in place since 2009 with a 6.25% target for biofuels in road and rail transport. Biodiesel constituted 59% of all biofuels, followed by ethanol (35%). In 2017 legislation introduced a sub-target for advanced biofuels, increasing it from 0.05% of energy used in road and rail transportation (for companies supplying more than 20PJ of fuels), up to 0.5% for all suppliers by 2025. Conventional biofuels are capped at 6.5% of the energy used in transportation. In 2015, Germany moved from an energy mandate to a GHG reduction quota with the goal of achieving a 6% GHG reduction in the transportation fuel mix by 2025.

Until 2014, fuel suppliers failing to meet the mandate were subjected to penalties of 0.7 EUR/litre of diesel equivalent for biodiesel and 1.55 EUR/litre of diesel equivalent for ethanol. Beginning in 2015, the penalty switched to 470 EUR/per ton of CO_{2eq} of GHG savings not achieved.

Italy

Italy has had a transportation biofuel obligation in place since 2006. In 2011, it began to transpose the RED, setting a minimum mandate of 5% blending by energy by 2014. In 2014 the biofuel mandate was amended to achieve 10% blending by 2022 and introduced a specific mandate for advanced biofuels. The country's biofuel sector is almost completely dominated by diesel substitutes (97%), mostly biodiesel (FAME) as well as a small share of HVO produced from palm oil. Italy has been consuming less palm-based biofuel over time and has increased consumption of biofuels produced from wastes and residues that can be double-counted towards the RED target, while decreasing the physical amount of biofuels consumed.

A new decree published in March 2018, amended the biofuel mandate from 10% to 9% by 2020. The 2018 mandate includes an obligation for advanced biofuels starting at 0.6% in 2018 and rising to 1.85% in 2022. 75% of the advanced biofuels target must be met with advanced biomethane and 25% by other advanced biofuels. Producers of biofuels are assigned Emission Certificates (Certificati di Immissione in Consumo or CIC) which can be traded and sold to suppliers, and can be used by authorities to verify compliance with the obligation. One CIC is assigned for each 10 Giga calorie (Gcal) of conventional biofuels supplied and for each 5 Gcal of advanced biofuels. There is a penalty of 750 EUR per missing certificate for suppliers that do not comply with the mandate; this is equivalent to 2.7 EUR/litre of diesel equivalent for conventional biofuels and 5.4 EUR/litre of diesel equivalent for advanced biofuels. This penalty can be reduced if supply on the market is less than 20% of the mandated quantity. Aviation biofuels cannot opt into the mandate and are not eligible to receive CICs.

The Netherlands

The Netherlands first placed renewable energy obligations on fuel suppliers in 2007, with the goal of achieving a share of 4% by 2010. The mandate was then updated in 2011 to grow from 4.25% to 10% in 2020, in line with the RED target. The main biofuels used in the Netherlands are FAME and HVO (82% of all biofuels) produced from used cooking oil, some of it imported from Asia and animal fats, followed by conventional ethanol. Advanced biofuels accounted for 0.1% of the transportation energy in 2017 and 1.6% of all biofuels delivered. Biomethane produced from municipal organic waste and sewage sludge constituted 74% of advanced biofuels consumed in the Netherlands.

In 2018, the Dutch government raised the biofuel mandate to 16.4% by 2020, including double-counting. The country increased the advanced biofuels mandate from 0.6% in 2018 to 1% by 2020. The remaining quota of the mandate is expected to be filled by double-counted biofuels. Aviation biofuels are not subject to the mandate, but bio-kerosene and bio-naphtha producers can opt in and be eligible to obtain renewable certificates.

Sweden

In Sweden the main support mechanism for biofuels has been exemptions from its energy and carbon taxes, which apply to fossil fuels. In 2018, the carbon tax was 1,150 SEK per ton CO2 (109 EUR/ton CO_2).

Almost 21% of the energy used for road vehicles in Sweden in 2017 came from biofuels. In the last three years, Sweden has doubled the share of biofuels sold, but most of the biofuels, or feedstocks, are imported. Importantly, the consumption of HVO has expanded in recent years.

In July 2018, Sweden introduced a new mandate on fuel distributors to reduce GHG emissions of the diesel and gasoline fuel mix supplied. This policy requires fuel distributors to decrease GHG emissions by 19.3% in the diesel supply and 2.6% in the gasoline supply by 2018. The reduction targets increase to 21% and 4.2% for diesel and gasoline, respectively, by 2020. Sweden has a longer-term target for a fuel mix that would achieve a GHG reduction of about 40% by 2030 corresponding to around 50% of biofuels blending. Tax exemptions for biofuels were removed, while the energy and carbon taxes are adjusted to meet the blend required to meet the GHG reduction target with the introduction of the new GHG targets. High-blended and pure biofuels, such as E85, HVO100 and biomethane, are not allowed within the reduction duty, but are still exempted from the energy and carbon tax.

The penalty for not complying with the reduction quota is 5 SEK/kg CO_{2eq}. (476 EUR/ton CO_{2eq}) for petrol and 4 SEK/kg CO_{2eq} (380 EUR/ton CO_{2eq}) for diesel. Sweden are considering specific measures for aviation biofuels.

United Kingdom

The UK introduced the Renewable Transportation Fuel Obligation (RTFO) in 2008, setting a biofuel mandate that started at 2.6% by volume in 2009 and increased up to 6% in 2018. Of biofuels consumed in the UK 48% are biodiesel (mostly UCO) and 47% ethanol (mostly wheat).

The UK amended the RTFO in the spring of 2018 to transpose requirements from the EU ILUC directive. The mandate has now been extended to 2032 and the ambition has significantly increased, aiming for a doubling of renewable fuels in road and nonroad mobile machinery transportation from 6% in 2017 to 12.4% in 2032.

The RTFO is based on traded certificates - one Renewable Transport Fuel Certificate (RTFC) is allocated for each litre of liquid renewable fuel produced. Renewable fuels produced from specific wastes and other feedstocks listed by the UK government are counted double and awarded two RTFCs for each litre of fuel.

With the 2018 amendment, the certificates are now differentiated into three categories of renewable fuels: relevant crop, development fuel, and general RTFCs. Each of these categories have specific prescriptions in the mandate. "Relevant crop fuels" refer to crop-based fuels; these are subject to a cap starting at 4% by volume in 2018, decreasing to 2% in 2032. "Development fuels" are advanced fuels with a sub-mandate and each litre is double-counted. To meet the criteria, development fuels must be produced from an eligible waste on the government list, or be a Renewable Fuel of Non-Biological Origin. Development fuels also include aviation fuel (both kerosene-type and gasoline-type fuels), substitute natural gas produced by gasification or pyrolysis, or hydrogen.

7.4 BRAZIL - THE RENOVABIO PROGRAM

The Brazilian National Biofuel Policy (also known as RenovaBio) aims at promoting an expansion in the production and use of biofuels in Brazil through incentivising improvements in terms of energy efficiency and of emissions responsible for anthropic climate change. Two main instruments will allow this to become a reality: (1) defining national targets of GHG emission reductions and (2) establishing a regulated market for trade in Decarbonisation Credits (or CBios) in the stock market. The amount of CBios a producer will be able to claim depends on the environmental performance of their biofuel production system, while fuel distributors will be obliged to purchase a given amount of CBios to fulfil their requirements of emission reduction. Since a CBio is equivalent to avoiding the emission of one tonne of CO_{2eq}, the amount of CBios a plant is able to generate can be easily estimated. For example, a standard mill processing 4 million tonnes of sugarcane per year for ethanol and electricity would be able to trade 484 thousand CBios on the stock market. Further energy optimisation and the use of straw could increase this figure to 498 thousand and 511 thousand CBios, respectively. This would represent an increase in the overall revenue of the plant, although the price range for CBios is still uncertain at the moment. However, the policy is expected to provide a significant incentive to increase production of sugar-based bioethanol while also providing sufficient incentive to stimulate investment in cellulosic ethanol and other advanced biofuel production systems (Klein, et al., 2019).

7.5 CONCLUSION

These are some examples of policy and regulatory portfolios which have been introduced and which are successfully leading to some early deployment and use of advanced biofuels.

The policies illustrate the more general international trend, with volume-based blending mandates being progressively refined and evolving into systems which incentivise GHG reductions more broadly in the transport sector.

The performance of such policies including the costs and impact on stimulating investment should be carefully monitored so that policy best practice can be identified and applied more widely.

8. Conclusions and recommendations

- Advanced biofuels play an important role in many low carbon scenarios yet so far, their production is only at a limited scale, and the costs are currently higher than conventional biofuels and the fossil fuels they aim to replace.

- Information gathered from industry and other sources for this study has largely confirmed the estimates of the current costs of producing advanced biofuels contained in the earlier SGAB cost analysis report. Costs lie in the range of 62 EUR/MWh to 158 EUR/MWh (17-44

EUR/GJ) for production based on biomass feedstocks, and 48 to 104 Euros/MWh (13-29 EUR/GJ) for waste-based production, illustrating the cost advantages of using such feedstocks.[9] This compares with a recent range of fossil fuel prices of 30-50 Euros/MWh (8–14 EUR/GJ).

- Early market opportunities exist for producing lower cost advanced biofuels from wastes, and through integration of advanced biofuel production with existing biofuels processing plants. However, such opportunities are relatively limited and will not in themselves enable production at levels likely to be needed to meet low carbon scenario expectations.

- There is significant potential for cost reduction through R&D and through experience being gained in the current generation of demonstration and early commercial plants. If a number of additional commercial plants are built, it is anticipated that capital and operating costs could be significantly reduced, while scope for feedstock cost reduction is judged to be more limited. Overall production costs could be reduced by between 5-27% compared to the current cost estimates. In addition, if increased experience makes it possible to finance plants on more favourable terms which would reduce costs further. For example, reducing the financing rate from 10 to 8% and extending the financing term from 15 to 20 years would further reduce costs by some 5-16%. Taken together these measures can reduce the production costs range for biofuels produced from biomass feedstocks to between 42 and 119 EUR/MWh (12-33 EUR/GJ) and 29-79 EUR/MWh (8-22 EUR/GJ) for waste based feedstocks .

- Large scale deployment of the technologies, in line with the patterns needed to meet the ambitions for advanced biofuels within a number of low carbon scenarios, could lead to additional significant cost reductions through technology learning, if plant capital and operating costs fall in line with a learning curve. Such reduction could be significant given large-scale roll-out of the technologies (potentially up to 50% further reductions in the most optimistic cases studied), although given the range of complicating factors it is difficult to estimate the scope for such reductions precisely.

- As capital and operating costs fall, the feedstock costs assume a greater importance in the overall cost structure. It is difficult to predict feedstock cost and price trends particularly in situations where demand is significantly scaled up. While global and regional studies indicate that significant quantities of wastes residues and energy crops could be available at roadside costs below 20 EUR/MWh, more detailed studies are needed to confirm that feedstocks could practically be delivered at these costs taking all the logistical and market factors into account.

- Comparison of the estimates of the current costs of production of the range of advanced biofuels with the prices of the fossil fuels that they aim to replace indicates a significant cost gap (of between 12 EUR/MWh and 128 EUR/MWh, (3-36 EUR/GJ)). If the medium-term cost reductions discussed above can be achieved the gap will be narrowed but will still be significant for many of the pathways.

- Policy support will therefore be needed to enable these technologies to mature either in terms of added value for low carbon fuels or a substantial carbon costs applied to fossil fuels. For biomass based fuels a carbon price in the range of 49-525 EUR/tonne CO_{2eq} is needed to bridge the current gap. This would be reduced to 0-365 EUR/tonne CO_{2eq} given sufficient market development in the medium term. This could be reduced further by cost reductions linked to learning effects stimulated by very large-scale deployment.

- In the longer term, the effective cost of using fossil fuels may rise through a combination of higher prices and more extensive carbon pricing, or other incentives may be available for low carbon transport fuels. If there is an extensive increase in the production capacity of advanced biofuels, then there is the prospect of the technologies being cost effective in the context of anticipated fossil and carbon prices such as those in the IEA's World Energy Outlook scenarios.

- While the costs of advanced biofuels and other fuels discussed above are an important factor, a broader range of issues also need to be considered when comparing these options and also when looking at other low-carbon options. These include the extent to which they can directly replace fossil fuels, the costs of any modifications or of distribution costs associated with fuels, the likely availability of feedstocks and the life-cycle GHG emissions and other sustainability criteria associated with particular routes. The overall consideration of the future for advanced biofuels needs to be seen in the context of these other factors as well as the energy costs.

- Large scale deployment will depend on continuing policy support. First, industry will need support during the demonstration and risky and costly early commercialisation of the technologies, so as to bridge the "valley of death". Continuing support will also be needed to offset the differences between biofuels and fossil fuel prices, either by internalizing external costs associated with GHG emissions associated with fossil fuel use or by incentivising low-carbon transport fuels.

- There are some examples of policy and regulatory portfolios which have been introduced and which are successfully leading to some early deployment and use of advanced biofuels. For example, in the US and especially in California the Renewable Fuel Standard and Low Carbon Fuel Standard provide effective market support at levels which are sufficient to stimulate the growth of advanced biofuels. Similar support is being introduced in other regions and the success of impact and costs of such policies should be monitored so that policy best practice can be identified and applied more widely.

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Appendices

Appendix 1 – List of Abbreviations

2DS	:	2°C Scenario
AD	:	Anaerobic Digestion
ART Fuels Forum	:	Alternative Renewable Transport Fuels Forum
bbl	:	barrel
bpd	:	barrels per day
CAD	:	Canadian Dollar, currency
CA-LCFS	:	California's Low Carbon Fuel Standard
CAPEX	:	Capital Expenditure cost
CARD	:	Centre of Agricultural & Rural Development
CBios	:	Decarbonisation Credits
CCU	:	Catalytic Cracking Unit
CCS	:	Carbon Capture and Storage
CHP	:	Combined Heat and Power
CI	:	Carbon Intensity
CIC	:	Certificati di Immissione in Consumo
CNG	:	Compressed Natural Gas
CPS	:	Current Policies Scenario
DDGS	:	Distillers Dried Grains with Solubles
DKK	:	Danish krone
DME	:	Dimethyl Ether
EJ	:	Exajoule
EPA	:	US Environmental Protection Agency
EUR	:	currency of the European Union (EU)
FAME	:	Fatty Acid Methyl Ester
FCC	:	Fuel Catalytic Cracking
FT	:	Fischer-Tropsch
Gcal	:	Giga calorie
GGE	:	Gasoline Gallon Equivalent
GHG	:	Green-House Gas
HVO	:	Hydrotreated Vegetable Oils
IEA	:	International Energy Agency
ILUC	:	Indirect Land Use Change
IRENA	:	International Renewable Energy Agency
LHV	:	Low Heating Value
LCFS	:	California Low Carbon Fuel Standard
LNG	:	Liquified Natural Gas
MCAD	:	Million Canadian Dollars
MGY	:	Million US gallons per year
MSW	:	Municipal Solid Waste
MT	:	Metric Tonnes
NPS	:	New Policies Scenario
ODT	:	Oven Dry Tonne
O&M	:	Operation & Maintenance
OPEX	:	Operational Expenditure cost
PFD	:	Process Flow Diagram
PJ	:	peta joule
PO	:	Pyrolysis Oil
PV	:	Photovoltaic
R&D	:	Research & Development
RDF	:	Refuse Derived Fuel
RED	:	Renewable Energy Directive
RFS	:	US Renewable Fuel Standard
RINs	:	Renewable Identification Numbers
ROM	:	Rough Order of Magnitude
RTFC	:	Renewable Transport Fuel Certificate
RTFO	:	Renewable Transportation Fuel Obligation
RVO	:	Renewable Volume Obligation

SDS	:	Sustainable Development Scenario
SEK	:	Swedish krona
SGAB	:	Sub-Group on Advanced Biofuels
SPK	:	Synthetic Paraffinic Kerosene
STF	:	Sustainable Transport Forum
UCO	:	Used Cooking Oil
USA	:	United States of America
USD	:	United States Dollar
US DOE	:	US Department of Energy
WEO	:	World Energy Outlook

Appendix 2 - Questionnaire to establish technology status and cost and cost reduction potential information

A2.1 INFORMATION TO ESTABLISH TECHNOLOGY STATUS

This questionnaire addresses the status and reliability of the range of technologies in the advanced biofuels sector by referring to plants in operation, or in some cases close to being in operation. Please note that the detailed information will not be disclosed outside the project core group without permission from the providers.

Please address the following issues.

- A short description of the plant(s) with name, location and background.
- List of key technologies utilised in the plant and a simple block flow diagram or Process Flow Diagram (PFD), including the feedstock preparation, processing and product upgrading (quality or specifications well defined) and the management of wastes and co-products. Note: If the processing includes off-site upgrading or co-processing with other biogenic or fossil feedstock, this upgrading part should also be included in the description.
- Classify the plant as a *Pilot plant (P)*, a *Demonstration plant (D)* or a *Commercial plant (C)*. Note that a technology development can encompass a sequence of plants from pilot and to commercial plants, and data on all stages can be considered. Where possible a photograph of the installation (approved for use in the official, public report).
- Description of type of feedstocks and compositional and price spans of feedstocks supplied at plant gate, including what is done to monitor / control the quality of received feedstock to ensure it is technically and economically feasible to process.
- Start-up year – plus current status.
- Plant size expressed as feedstock consumption, e.g., as ton dry biomass/day or MW Low Heating Value (LHV) plus other important feeds/utilities such as electric power, hydrogen etc.
- Plant product capacity expressed as ton product/day, m^3 product/day, Nm^3 product/h of product or similar - including important co-products.
- Conversion efficiency number, e.g. tons of product per ton of dry biomass or MW_{out}/MW_{in}. should be able to be calculated from item 2 and 3 – if available, provide status of progression / timeline of on-going process efficiency improvement and cost reduction implications.
- Number of hours of operation since start-up (comment on length of continuous operation or similar) – reliability description, demonstrated availability of production capacity (% on time).
- Next step (e.g., first full-sised plant planned for start-up in year 20xx) – status.
- Comment potential technology barriers or potential show-stoppers.

The information will be summarised in a format such as in the following table.

Plant	Type P/D/C	Start-up year	Feedstock capacity	Product	Co-product MW	Hours in operation

A2.2 BIOFUEL PROCESS COST TEMPLATE

Information obtained from industry and public sources will be aggregated into a brief process description and economic figures, expressed as production cost in EUR/MWh or EUR/GJ. The bases for the production costs will be aggregated into one of three categories:

1) Feedstock costs

2) other operating costs (noting the foremost cost drivers as relevant for the technology) or

3) capital-related costs.

Capital Investments

- The capital investment (either in absolute or as specific investment per unit of product) should be associated with a product capacity per year.
- Where appropriate distinguish between a stand-alone facility and a facility which is integrated with an existing plant (e.g. a conventional biofuel plant) or which co-processes material with biogenic or fossil feedstocks, and including necessary modifications to the second facility.

Operating costs for the facility (for the first case or both cases above, as relevant for the technology):

- Expected annual full load equivalent operating hours or capacity factor based on nameplate capacity. Typical base number is 8,000h of operation per year.
- Typical mass or energy conversion data from raw feedstock to biofuel product.
- Typical maintenance costs for the full installation (preferably expressed as % of investment, however if major and recurring specific maintenance interventions are required in certain intervals, this can be noted). Explain basis for this maintenance estimate.
- Typical use of major chemicals (type, rough quantity, cost).
- Typical use of energy and utilities (type, rough quantity, cost).
- Other operating costs not included above (materials and energy not included above, staffing, overhead, other indirect costs etc.).
- Any significant revenues from by-products (type, rough quantity, value).

Overall O&M costs (excluding feedstock feedstock) can also be aggregated and its content be described with some sentences. The report will always aggregate supplied, detailed data.

1. Scope for cost reduction

What do you see as the potential for reduction of capital or operating costs or improvement in conversion efficiency if you were able to develop a series of additional plants, taking into account the following factors:

- the impact of R&D,
- experiential learning,
- scale-up economies of scale,
- scope for integration with other processes and leveraging/using existing infrastructure,
- adding value to co-and by-products,
- What would you expect to be the trends in feedstock costs if you were able to build a series of plants?
- Once the technology is established and operation demonstrated at a commercial scale, what would you expect to be the impact on financing costs once there is added confidence in the technologies (assuming a stable policy framework which provides security that the output will be marketable).

Appendix 3 - Examples of Policy Initiatives

A3.1 US RFS AND CALIFORNIA LCFS

A3.1.1 US Renewable Fuel Standard

The RFS, administered by the US Environmental Protection Agency (EPA), requires that certain minimum amounts of the four types of renewable transportation fuels shown in Table 22 (EPA, 2017a) (Gottumukkala & Hayes, 2018) are used in the US.

Table 22. Renewable fuels categories under the RFS program.

Category	Code	Minimum GHG reduction requirement [a]	Description
Cellulosic Biofuel	D3	60%	Renewable fuels made from cellulose, renewable gasoline, biogas-derived CNG and LNG.
Cellulosic Diesel	D7	60%	Cellulosic diesel, jet fuel and heating oil.
Advanced Biofuels	D5	50%	Renewable fuels other than ethanol derived from corn starch (sugar cane ethanol), biogas from other waste digesters, etc.
Biomass-Derived Diesel	D4	50%	Renewable fuels that meet the definition of either biodiesel or non-ester renewable diesel.
Renewable Fuel	D6	20%	Renewable fuels produced from corn starch or any other qualifying renewable biomass.

[a] compared to the petroleum baseline

Specific quantities of each renewable fuel type are allocated to obligated parties who can comply by blending "renewable fuels" into transportation fuel, or by obtaining credits, called "Renewable Identification Numbers" (RINs) to meet their obligation. RINs are saleable regulatory credits that represent a quantity of qualifying renewable fuel. To qualify as a renewable fuel under the RFS program, a fuel should be produced from an approved feedstock through an approved pathway. For a given approved feedstock, there can be several approved conversion processes. RINs are generated when a producer makes a gallon of renewable fuel and these RINs are then attached to it. Obligated parties should blend the renewable fuel into fuel derived from petroleum, or purchase RINs credits to meet their specified annual volume obligation. RINs are traded in two forms:

1) "assigned RINs" are directly associated with a batch of fuel from party to party and purchasers obtain both the renewable fuel and the RINs together; and

2) "separated RINs" are separated from the batch of renewable fuel produced and are traded separately.

The renewable fuel producer generates these separated RINs and market participants can then trade these RINs with obligated parties that can obtain and retire them for compliance with annual RVOs (Gottumukkala & Hayes, 2018). Figure 21 shows a schematic of the lifecycle RINs under the RFS program (EPA, 2017b).

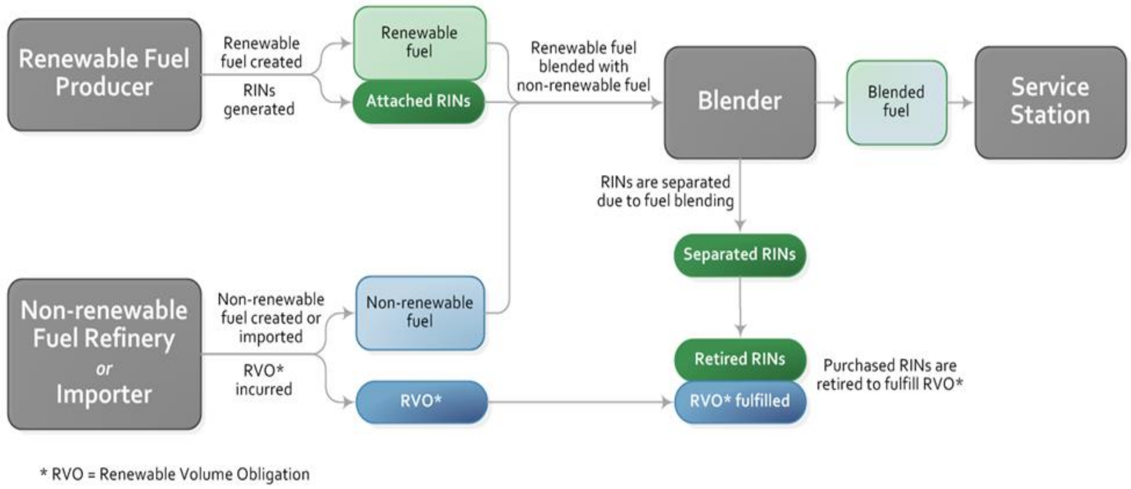

Figure 21. Lifecycle of a Renewable Identification Number (RIN) under RFS program.

The price of RINs is set by market forces. The RFS determines the demand for RINs by specifying how much biofuel, and therefore how many RINs, need to be sold in aggregate each year. Biofuel producers determine the supply. As demand for RINs or the cost of producing biofuel increases, the price of RINs will increase and vice versa (Lade & Bushnell, 2016). RINs prices from 2015 to 2018 are shown in Figure 22. As shown in Figure 22, cellulosic RINs (cellulosic biofuels) have the highest RIN value, followed by biomass-based diesel, advanced biofuels and general renewable fuels (corn ethanol). Annual RVOs force the obligated parties to acquire specific percentages of RINs from categories of fuel that contribute to significant reductions in GHG emissions, in particular advanced and cellulosic biofuels (EPA, 2018).

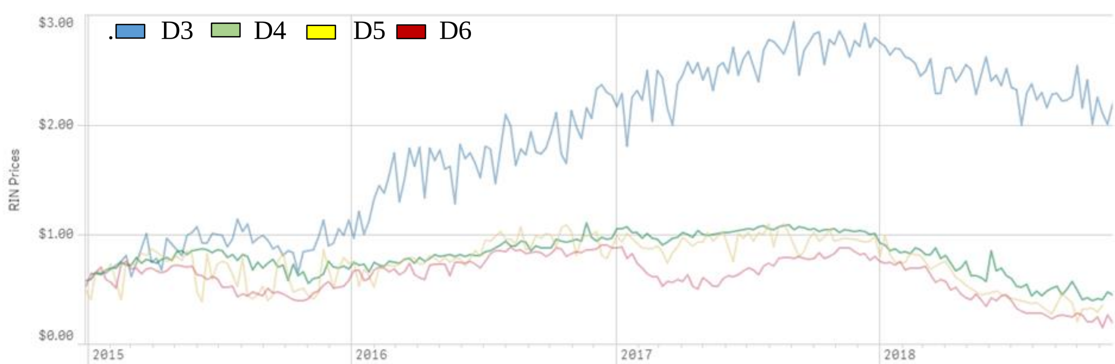

Figure 22. RIN prices for renewable fuels under RFS program, 2015-2018.

A3.1.2 California's Low Carbon Fuel Standard (LCFS)

Compared to the RFS program in which there are volumetric mandates for renewable fuels, California LCFS has carbon reduction incentives for low carbon fuels. LCFS program is fuels agnostic, with credits or deficits generated based on the Carbon Intensity (CI) of the participation fuels. All fuels and energy systems compete against each other including natural gas, electric vehicles, biofuels, etc. Figure 23 shows the volumes of alternative fuels (low carbon fuels) consumed in California from 2011 to 2017. The total volume increased from 1,152 million gasoline gallon equivalent (GGE) in 2011 to 1,930 GGE in 2017, a 60% increase in the use of alternative fuels in California.

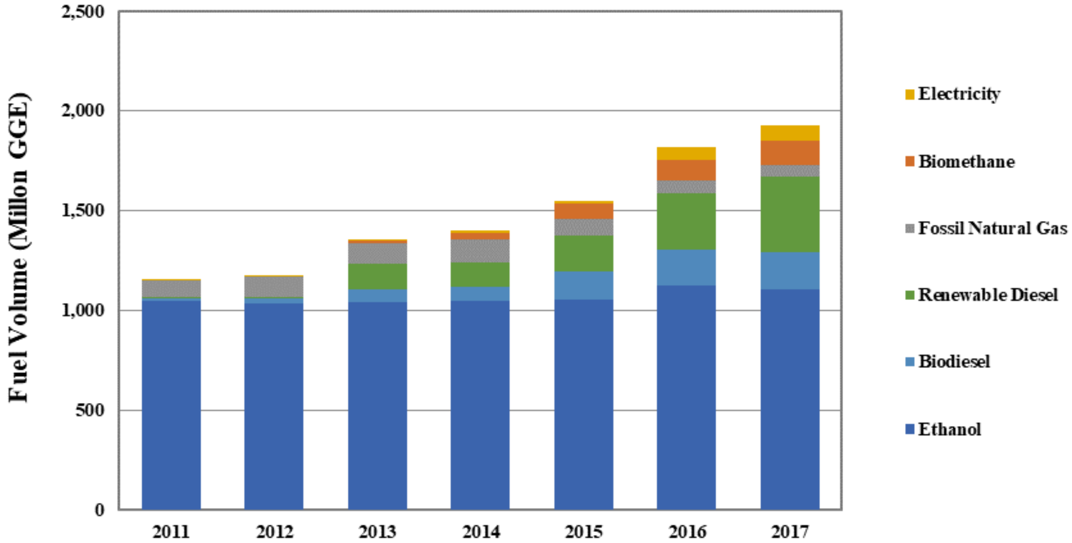

Figure 23. Volumes of alternative fuels under Californian LCFS 2011 to 2017.

Source: (Lane, 2018)

Figure 24 shows the volume of transacted credits (metric tons (MT) CO_{2eq}) and the credit prices (USD/MT CO_{2eq}) from 2013 to 2018. The current credit price is 190 USD/MT CO_{2eq}. The average credit price since 2013 was 81 USD/MT CO_{2eq}.

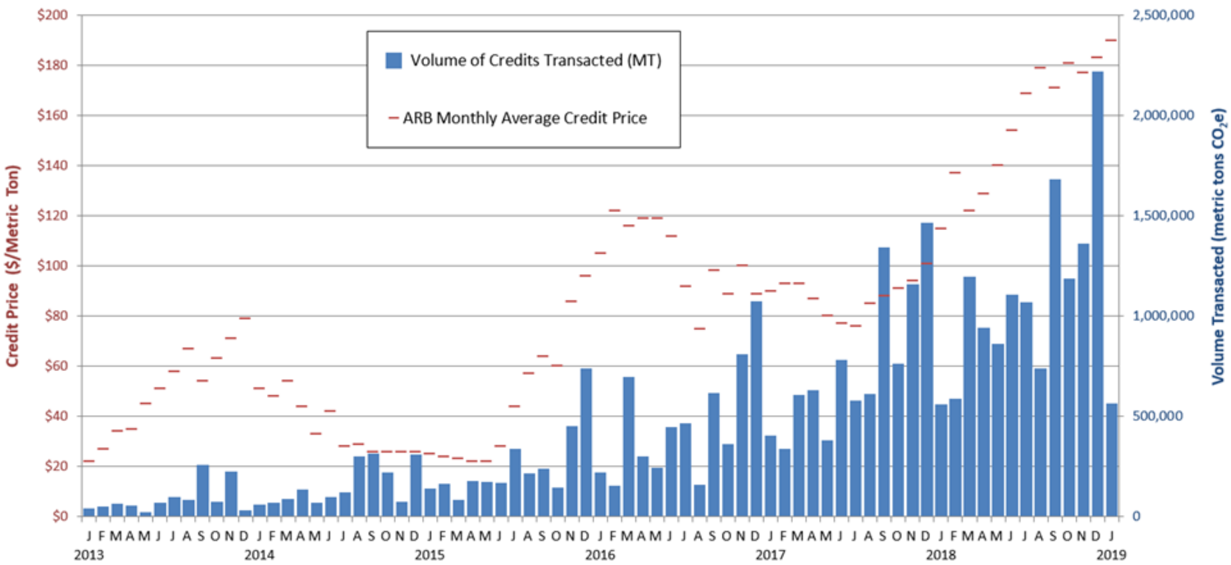

Figure 24. Monthly LCFS credit price and transaction volumes, 2013-2018.

Source: California Air Resources Board, (2019).

Table 23 shows the conversion of CI score ($gCO2_{eq}/MJ$) and credit price ((USD/MT of CO_{2eq}) to the credit value per GGE of fuel (USD/GGE) as revenue for alternative fuel producers. For example, for alternative fuel with the current credit price of 190 USD/MT CO_{2eq} and the CI score of 40 gCO_{2eq}/MJ, the credit value will be 1.17 USD/GGE. This credit value will be added to the base fuel price based on its energy content and the RIN credit (if the alternative fuel is qualified under the RFS program).

Table 23. Alternative low carbon fuel premiums at sample LCFS credit prices.

CI Score (gCO_{2eq}/MJ)	Credit Price USD					
	$190	$80	$100	$120	$160	$200
-273	$8.06	$3.39	$4.24	$5.09	$6.79	$8.48
10	$1.83	$0.77	$0.96	$1.16	$1.54	$1.93
20	$1.61	$0.68	$0.85	$1.02	$1.36	$1.70
30	$1.39	$0.59	$0.73	$0.88	$1.17	$1.46
40	$1.17	$0.49	$0.62	$0.74	$0.99	$1.23
50	$0.95	$0.40	$0.50	$0.60	$0.80	$1.00
60	$0.73	$0.31	$0.38	$0.46	$0.62	$0.77
70	$0.51	$0.22	$0.27	$0.32	$0.43	$0.54
80	$0.29	$0.12	$0.15	$0.18	$0.25	$0.31
90	$0.07	$0.03	$0.04	$0.04	$0.06	$0.07
100	-$0.15	-$0.06	-$0.08	-$0.09	-$0.13	-$0.16
110	-$0.37	-$0.16	-$0.19	-$0.23	-$0.31	-$0.39
120	-$0.59	-$0.25	-$0.31	-$0.37	-$0.50	-$0.62
130	-$0.81	-$0.34	-$0.43	-$0.51	-$0.68	-$0.85
140	-$1.03	-$0.43	-$0.54	-$0.65	-$0.87	-$1.08
150	-$1.25	-$0.53	-$0.66	-$0.79	-$1.05	-$1.32
100.82	-$0.14	-$0.06	-$0.07	-$0.09	-$0.11	-$0.14

Source: California Air Resources Board, (2019).

A3.2 EUROPEAN UNION - THE RENEWABLE ENERGY DIRECTIVE (RED)[10]

A3.2.1 The Renewable Energy Directive of 2009 (RED)

The primary source of EU legislation currently in force regarding biofuels is the RED (2009/28/EC, 2009), which establishes an overall policy for the production and promotion of energy from renewable sources in the EU. A requirement is imposed on EU Member States to obtain a share of energy from renewable sources in all forms of transport of at least 10% by 2020. It is generally accepted that biofuels will be the main renewable energy source in attempting to reach this target. By means of an amendment (the so called ILUC Directive) implemented in 2015 (2015/1513 EU, 2015) a limit of 7% has been imposed for biofuels produced from crops grown on agricultural land for the purpose of the calculation of the 10% target. There is an exception for certain specific feedstocks and fuels, which include advanced biofuels as well as biofuels produced from used cooking oil and animal fats. These fall outside the 7% limit. This 7% limit was introduced to address concerns related to indirect land use change (ILUC). There is also an indicative target of 0.5% for advanced biofuels. Finally, advanced biofuels, as well as biofuels produced from used cooking oil and animal fats are double counted towards the 10% target.

In order to be counted towards the target biofuels must meet certain sustainability criteria, irrespective of whether they were produced using raw materials cultivated inside or outside the EU. This is to ensure that the biofuels consumed in the EU are sustainable. The sustainability criteria consist of various requirements. First, the GHG emission savings from the use of biofuels as compared to the use of fossil fuels must amount to at least 60% for biofuels produced in installations starting operation after 5 October 2015. With respect to installations that were in operation on or prior to this date, the GHG emission savings had to amount to at least 35% until 31 December 2017, and since then they must amount to at least 50%. Furthermore, in order to meet the sustainability criteria biofuels may not be made from raw material deriving from land with high biodiversity value, high carbon stock, or peatland, as defined in the RED. The RED provides for several possibilities for producers to calculate the GHG emission saving levels of a particular type of biofuel, namely by: relying on default values for GHG emission savings that assign a standard GHG emission saving value for each type of biofuel depending on the raw material used; calculating the actual GHG emission savings themselves, using a method provided for in the Directive; or calculating actual values for one or more steps in the production process, while relying on disaggregate default values for the remaining steps. Details regarding the calculation of the default values are provided in the RED. In order to further increase the flexibility of the measure, the Commission approved via Comitology procedures independent voluntary certification schemes. There are several approved voluntary certification schemes that market operators can use (European Commission, 2019). Finally, financial support for the consumption of biofuels may only be given to biofuels meeting the sustainability criteria. EU Member States must report to the European Commission every two years the progress they have achieved with respect to their implementation of the RED, including with respect to biofuels. The European Commission must monitor several elements under the RED in general, but also specifically related to biofuels, and publish consolidated reports for the EU based on its monitoring as well as the Member State reports.

[10] Extracts from ART Fuels Forum, Advance Biofuels in India: A comparative analysis between India and the EU for cooperation and investment, Final Report, Radhika Singh, Stamatis Kalligeros & Jai Uppal, October 2018.

A3.2.2 The recast of the Renewable Energy Directive – RED-II (2018/2001 EU Directive, 2018)

The RED-II was adopted on of 11 December 2018 and the Member States will have to transpose the RED-II by 30 June 2021 and the original RED will be repealed as from 1 July 2021.

The RED-II like the RED defines advanced biofuels as biofuels that are produced from feedstocks as listed under part A of Annex IX. The RED-II puts forth a Union binding overall target to ensure that the share of energy from renewable sources in 2030 is at least 32%. Furthermore, a requirement is imposed on EU Member States to require fuel suppliers to ensure that the share of renewable energy supplied for final consumption in the transport sector is at least 14% by 2030. This share is calculated as the sum of all biofuels, biomass fuels (subject to fulfilling the sustainability and greenhouse gas emissions saving criteria set out in the directive) and gaseous transport fuels of non-biological origin used in the transport sector.

For the purpose of the calculation of the 14% target, the use of biofuels and biogas produced from feedstocks listed in Part B of Annex IX (see Annex) i.e. used cooking oil and animal fat, is limited to 1.7%. This contribution will be double-counted towards the 14% target. The Commission can add feedstocks to Part B of Annex IX, but not remove them. The feedstocks it can add to Part B of Annex IX are those that can be processed with mature technologies. Similarly, for the purpose of the calculation of the 14% target, the contribution of fuels supplied in the aviation and maritime sector will be considered to be 1.2 times their energy content. The share of biofuels, bioliquids and biomass fuels produced from food or feed crops in each Member State may not be more than 1% higher than their share in 2020. However, their share is capped at 7% of the gross final consumption in road and rail transport. Moreover, in case this share is below 1%, the contribution may be increased to a maximum of 2%. If a Member State's share of biofuels, bioliquids, biomass fuels produced from food or feed crops is less than the aforementioned 7%, the Member State may reduce the overall 14% target accordingly by maximal 7 percentage points. For example, in case a Member State has limited the contribution from biofuels, bioliquids, biomass fuels produced from food or feed crops to 2%, it may reduce the overall 14% target to 9%.

The RED-II defines advanced biofuels as biofuels that are produced from feedstocks listed in Part A of Annex IX of the directive. It provides that biofuels and biogas produced from these feedstocks shall equal to at least 0.2% in 2022, 1% in 2025 and 3.5% in 2030, gradually increasing their share over time. Furthermore, the contribution of advanced biofuels will be double-counted towards the 14% target. The Commission can add feedstocks to Part A of Annex IX, but not remove them. In other words, the Commission can add feedstocks to the list of advanced biofuels. The feedstocks it can add to Part A of Annex IX are those that can only be processed with advanced technologies.

The RED-II lays down certain sustainability and greenhouse gas emissions saving criteria for biofuels, bioliquids and biomass fuels in order for them to be counted for the contribution towards the Union target and Member States renewable energy share in compliance with renewable energy obligations; and eligible for financial support. These criteria apply irrespective of the geographical origin of the biomass. The RED-II for the purposes of the sustainability criteria differentiates between biofuels, bioliquids and biomass fuels produced from agricultural biomass and those produced from forest biomass. Therefore, the sustainability criteria for the two differ.

Default GHG emission values and calculation rules are provided in Annex V (for liquid biofuels) and Annex VI (for solid and gaseous biomass for power and heat production) of the RED II. The Commission can revise and update the default values of GHG emissions when technological developments make it necessary. Economic operators have the option to either use default GHG intensity values provided in RED II or to calculate actual values for their pathway. Table 24 below outlines the Greenhouse gas savings thresholds in RED II (European Commission, 2019).

Table 24. Greenhouse gas savings thresholds in RED II.

Plant operation start date	Transport biofuels	Transport renewable fuels of non-biological origin	Electricity, heating and cooling
Before October 2015	50%	-	-
After October 2015	60%	-	-
After January 2021	65%	70%	70%
After January 2026	65%	70%	80%

Biofuels, bioliquids and biomass fuels from agricultural biomass must not be produced from raw materials originating from:

High biodiversity land (as of January 2008), including: primary forests; areas designated for nature protection or for the protection of rare and endangered ecosystems or species; and highly biodiverse grasslands;

High carbon stock land that changed use after 2008 from wetlands, continuously forested land or other forested areas with trees higher than five metres and canopy cover between 10% and 30%;

Land that was peatland in January 2008.

A3.2.3 Appendix 2 - ANNEX IX of RED II

ANNEX IX Part A. Feedstocks and fuels, the contribution of which towards the target referred to in the first subparagraph of Article 3(4) shall be considered to be twice their energy content:

a) Algae if cultivated on land in ponds or photobioreactors.

b) Biomass fraction of mixed municipal waste, but not separated household waste subject to recycling targets under point (a) of Article 11(2) of Directive 2008/98/EC.

c) Bio-waste as defined in Article 3(4) of Directive 2008/98/EC from private households subject to separate collection as defined in Article 3(11) of that Directive.

d) Biomass fraction of industrial waste not fit for use in the food or feed chain, including material from retail and wholesale and the agro-food and fish and aquaculture industry, and excluding feedstocks listed in part B of this Annex.

e) Straw.

f) Animal manure and sewage sludge.

g) Palm oil mill effluent and empty palm fruit bunches.

h) Tall oil pitch.

i) Crude glycerine.

j) Bagasse.

k) Grape marcs and wine lees.

l) Nut shells.

m) Husks.

n) Cobs cleaned of kernels of corn.

o) Biomass fraction of wastes and residues from forestry and forest-based industries, i.e. bark, branches, pre- commercial thinnings, leaves, needles, tree tops, saw dust, cutter shavings, black liquor, brown liquor, fibre sludge, lignin and tall oil.

p) Other non-food cellulosic material as defined in point (s) of the second paragraph of Article 2.

q) Other ligno-cellulosic material as defined in point (r) of the second paragraph of Article 2 except saw logs and veneer logs.

r) Renewable liquid and gaseous transport fuels of non-biological origin.

s) Carbon capture and utilisation for transport purposes, if the energy source is renewable in accordance with point (a) of the second paragraph of Article 2.

t) Bacteria, if the energy source is renewable in accordance with point (a) of the second paragraph of Article 2.

Part B. Feedstocks, the contribution of which towards the target referred to in the first subparagraph of Article 3(4) shall be considered to be twice their energy content:

a) Used cooking oil.

b) Animal fats classified as categories 1 and 2 in accordance with Regulation (EC) No 1069/2009 of the European Parliament and of the Council.

Appendix 4 - Units of measure and conversion factors

A4.1 UNITS OF MEASURE

kilo (k)	10^3
mega (M)	10^6
giga (G)	10^9
tera (T)	10^{12}
peta (P)	10^{15}
exa (E)	10^{18}

EJ	exajoule
GJ	gigajoule
ktoe	kilotonnes of oil-equivalent
kWh	kilowatt-hour
Mtoe	mega-tonnes of oil-equivalent
MBTU	millions of British thermal units
MJ	megajoule
MW	megawatt
MWh	megawatt-hour
GJ	gigajoule
GW	gigawatt
GWh	gigawatt-hour
toe	tonne of oil equivalent
TWh	terawatt-hour

A4.2 CONVERSION FACTORS

Energy units

1 MWh = 3.6 GJ = 0.086 toe = 3.41 MBTU

1GJ = 0.28 MWh = 0.024 toe = 0.95 MBTU

1toe = 41.87 GJ = 11.63 MWh = 39.66 MBTU

1 litre ethanol is equivalent to 5.86 kWh or 21.1 MJ

1 litre of gasoline is equivalent to 8.89 kWh or 32.0 MJ

1 litre diesel fuel is equivalent to 10.0 kWh or 36.0 MJ

Energy costs units

1 EUR/MWh= 0.277 EUR/GJ =0.265 EUR/MMBTU=11.63 EUR/toe.

1 EUR/kW assuming 8,000 hrs operation/year= 0.035 EUR/GJ/year

Note that 1 EUR = c. 1.15 USD

Volume

1 US Gallon = 3.785 litres

Production capacity

A biofuels plant with an output of 100 MW operating for 8000 h/year would produce fuel with an energy content of 800 GWh, or 2.88 PJ. This is equivalent to:

- 108 thousand tonnes of ethanol (137 million litres or 36 million US Gallons)
- 144 thousand tonnes of methanol (183 million litres or 48 million US Gallons)
- 65.5 thousand tonnes of HVO (84 million litres or 22 million US Gallons)
- 66 thousand tonnes of gasoline (90 million litres or 24 million gallons)

Feedstock costs

1 tonne of dry biomass contains around 18 GJ or 5 MWh.

A feedstock cost of 20 EUR/MWh is therefore equivalent to some 5.56 EUR/GJ, or 100 EUR/dry tonne.

IEA Bioenergy

Further Information

IEA Bioenergy Website
www.ieabioenergy.com

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