ADVANCEFUEL

# D3.5 First data on efficient, low-risk ramp-up of liquid biomass conversion technologies - from short time to long term

Author: Paraskevi Karka, Stavros Papadokonstantakis, Filip Johnsson
Organisation: Chalmers University of Technology
City, Country: Gothenburg, Sweden

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## *ADVANCEFUEL at a glance*

ADVANCEFUEL (www.ADVANCEFUEL.eu) aims to facilitate the commercialisation of renewable transport fuels by providing market stakeholders with new knowledge, tools, standards and recommendations to help remove barriers to their uptake. The project will look into liquid advanced biofuels – defined as liquid fuels produced from lignocellulosic feedstocks from agriculture, forestry and waste – and liquid renewable alternative fuels produced from renewable hydrogen and CO2 streams.

In order to support commercial development of these fuels, the project will firstly develop a framework to monitor the current status, and future perspectives, of renewable fuels in Europe in order to better understand how to overcome barriers to their market roll-out. Following this, it will investigate individual barriers and advance new solutions for overcoming them.

The project will examine the challenges of biomass availability for second-generation biofuels, looking at non-food crops and residues, and how to improve supply chains from providers to converters. New and innovative conversion technologies will also be explored in order to see how they can be integrated into energy infrastructure.

Sustainability is a major concern for renewable fuels and ADVANCEFUEL will look at socio-economic and environmental sustainability across the entire value chain, providing sustainability criteria and policy-recommendations for ensuring that renewable fuels are truly sustainable fuels. A decision support tools will be created for policy-makers to enable a full value chain assessment of renewable fuels, as well as useful scenarios and sensitivity analysis on the future of these fuels.

Stakeholders will be addressed throughout the project to involve them in a dialogue on the future of renewable fuels and receive feedback on ADVANCEFUEL developments to ensure applicability to the end audience, validate results and ensure successful transfer and uptake of the project results. In this way, ADVANCEFUEL will contribute to the development of new transport fuel value chains that can contribute to the achievement of the EU's renewable energy targets, and reduce carbon emissions in the transport sector to 2030 and beyond.

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# Executive Summary

This report presents a methodological framework which discusses the way of implementation of biomass processes in short and long term (Year 2020 until 2050) considering technology maturity and providing the first data on projected capacity growth rates and costs. The choice of the products and pathways for demonstration of the learning curve methodology is based on a sample of those proposed in ADVANCEFUEL framework and already analyzed in Deliverables 3.2 and 3.4. Two common fuels are selected, methanol and dimethyl-ether (DME) because they are already produced and used at commercial scale, and their production via Syngas intermediate from biomass gasification is presented as a potentially efficient, low risk technology, based on the TRL and cost argumentation in D3.2.

This deliverable is divided into two parts:

**The first part** provides mass and energy balances and waste (waste, solid) production, and cost data for the selected biomass conversion technologies. The cost data are restricted to capital costs (CAPEX), from biomass delivery point to the ready biofuel and decomposition of cost information at unit operation level.

**The second** part includes a review of the learning curve theory and how this is applied to estimate CAPEX values for methanol and DME production for years 2020, 2030 and 2050. A learning curve typically describes the estimated cost reduction as a result from experience of implementation of the technology in terms of numbers of units implemented. The parameters of the learning curve theory are the learning rates (LR), the initial cumulative installed capacity (CIC) and the potential annual growth rate (CAGR) of the investigated processes. For instance, according to literature review, we see that an innovative technology is expected to have LR value close to 20% and more mature technologies less than 10%. The production pathways of methanol and DME are first decomposed in process steps which are then independently characterized with respect to the parameters of the learning curve theory using values obtained from literature or assumptions based on similarity to reported processes. Based on the literature values of the learning parameters LR and CAGR we apply reference, conservative and optimistic scenarios for these values. These yield ranges of future investment costs for methanol and DME production technologies and, thus, on the expected reduction in capital costs for the methanol and DME processes.

In the case of methanol and DME, the analysis shows that the gasification step (and in particular the gasifier with the syngas cleaning steps) lowers the overall TRL, with only very few demonstration plants

reaching an adequate operational performance for scaling-up. The application of the learning curve framework gives a reduction of capital costs for the methanol and DME processes of around 11-18% by 2030 and 20-35% by 2050 for the reference case scenario. The conservative and optimistic scenarios for the future LR and CAGR values yield capital cost reduction of 5-8% by 2030 and 11-18% by 2050 for the conservative scenario and 18-29% by 2030 and 31-51% by 2050 for the optimistic scenario. These values can be compared with expert estimates based on real world experience which foresee cost reductions of not more than around 10% until year 2030 based on a large gasification project including the gas processing steps required to obtain a high-quality synthetic gas. Thus, this value is somewhere between the conservative and the reference scenario.

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# 1. Introduction

This deliverable is composed in two parts which consist of:

**Part A:** This section of the deliverable provides mass and energy balances and waste (waste, solid) production, and cost data for a selection of biomass conversion technologies. The cost data are restricted to capital costs (CAPEX), from the biomass delivery point, to ready biofuel. Thus, the cost of the biomass is not included.

**Part B:** This section of the deliverable includes a review of the learning curve theory, and how this is applied to estimate CAPEX values in years 2020[1], 2030 and 2050. Thus, an obvious interest is to try to estimate future costs for biomass conversion technologies. A learning curve typically describes the estimated cost reduction as a result from the experience of implementation when considering the technology in terms of numbers of units implemented.

CAPEX values collected in Part A are used as input in Part B for the application of the learning curve theory. These CAPEX values are considered either as starting points for the first-of-a-kind plant or as target points for the nth-of-a-kind (mature technology) plant, and their evolution along time, is investigated. The parameters of learning rates (LR), the initial cumulative installed capacity (CIC), and the potential annual growth rate (CAGR), of the study processes and their unit operations are necessary for cost projections. Their values were obtained from literature reviews or assumptions based on processes with similar characteristics.

When estimating future cost of biomass conversion technologies for production of advanced biofuels (second generation of biofuels), there are three important aspects to be considered for an analysis of what is required for such technologies to be applied at scale:

1. As opposed to solar PV and wind power, which are technologies for which each unit is comparably small and produced in a modular-type designs (specifically solar PV) and, thus, available in high numbers, biomass conversion technologies for second generation biofuels are only available in limited numbers. Globally, only 14 projects are available (Arvidsson, 2014) but these are either small, have been closed down or are in their planning phase (this if considering plants which are meant to produce a sufficiently clean gas to be of fuel standard. The main cost estimates are purchase costs of equipment, civil engineering works and service. It is a reasonable

[1] Year 2020 is obviously somewhat artificial in terms of a projection (application of learning theory from 2018 to 2020), since at the time of writing this (August 2019) it is half a year until this. Thus, the 2020 values should merely be seen as present-day values if experiences available so far could be applied.

assumption that it is the latter case where most learning can be expected. Therefore, what is reported here can only be used for an estimation of a likely cost development and what is governing this development.

2. Related to the above point, there are basically no full-scale plants available for advanced biofuel production, at least no plants that are operated on a commercial basis. This makes cost estimations of future plants a great challenge.
3. A substantial part of biofuel costs are the costs of the biomass. This means that if large facilities for fuel production are implemented, they will most likely affect the price of biomass and, thus, the cost for biofuels. This has an important implication from a policy perspective: It must be an increased cost of fossil fuels (or some mandatory targets on biofuel share in the fossil fuels) which drives implementation of biofuels and not subsidies. Subsidies can be important for demonstrating new technologies but will not be sustainable in the long run. As a result of this, (and as mentioned above), implementation of large-scale biofuel production processes with an increased number of such plants will increase the biomass feedstock price. Thus, there would be an ever-increasing funding for subsidising new plants, unless the price of the fossil-fuel alternative can be established higher than the price of biofuel (or there is a mandatory requirement on the relation between renewable and fossil shares in fuels sold).

# 2. Conversion technologies

Two thermochemical pathways are selected to represent first examples of low-risk efficient ramp-up of liquid biomass conversion technologies, and their evolution from short term to long term: methanol and DME production, in both cases from lignocellulosic biomass (hybrid poplar wood chips). These technologies are selected for the current analysis as they are well documented in literature and they were included in the analysis of the gasification pathways described in the Deliverable 3.2 and 3.4. According to the outcome of Deliverable 3.2, the gasification-based pathways are well established (i.e., demonstrated at the commercial scale) with respect to the syngas-based synthesis technologies. What lowers the overall TRL of this pathway is the gasification step, with only very few demonstration plants reaching an adequate operational performance with scale-up perspectives. The dimension of maturity expressed through cost reduction is part of the scope of this current deliverable.

## 2.1 Methanol and DME process description

Data sources for methanol and DME production are obtained from two different studies, from Pacific Northwest National Laboratory (PNNL) (Zhu, et al., 2011), and from VTT (Hannula, et al., 2013). These studies provide detailed information of operating units and mass and energy balances. The PNNL study specifically, provides results from process simulation models the process disaggregated into the main process steps for the entire pathway up to the end product, and that they have the highest cost and contribution in the technological maturity of the process. The study of PNNL describes the gasification pathway, including direct and indirect gasification, and provides detailed techno-economic analysis.

**Methanol**: For the case of methanol, the processing steps include:

- Feed handling and preparation
- Gasification
- Tar reforming and scrubbing
- Syngas clean-up and steam reforming (and water-gas shift for directly-heated gasifier system)
- Clean syngas compression
- Methanol production and purification

In the PNNL study, for the case of an indirect gasification technology, heat for maintaining the gasification process is fed from an external combustor into the gasifier in which the biomass is dried and gasified. The combustor burns the char which comes from the gasifier. The syngas from the gasifier is conditioned prior to steam reforming. The gasification can be carried out in an indirectly or directly heated gasifier.

An indirect gasifier system can be designed as a dual-fluidized bed system with the gasifier in one bed and the combustor in the other (for char burnout and providing heat for the gasification process), including a steam cycle for fluidising the gasifier. The process is typically operated under atmospheric pressure. Dried wood is fed into the indirectly heated gasifier. Steam extracted from the steam cycle is sent to the gasifier to fluidise the bed and to supply a portion of the heat required for the gasifier. The indirectly heated gasification reactor is typically operated at 780°C -870°C, and near atmospheric pressure. Heat is supplied by circulating hot particles (e.g. olivine) between the gasifier and the separate combustor. A steam reformer is used to convert the remaining tar, light hydrocarbons, and $CH_4$ to $H_2$ and CO, and to adjust the $H_2$/CO ratio to that required by methanol synthesis. Excess $CO_2$ is removed in an amine-based absorption unit. The clean syngas is then compressed and sent to the methanol synthesis section to produce crude methanol. The crude methanol is then delivered to distillation units to purify it to the highest grade of methanol. Part of the purge gas from methanol synthesis and volatiles from distillation columns are used as fuels for steam reformer burners, and biomass dryers. Steam generated throughout the process is collected and sent to the steam cycle for power generation and for direct use in steam reforming and other processes.

A directly heated gasifier is commonly designed as an oxygen-blown pressurised fluidized bed reactor. In this reactor, the heat required by endothermic gasification reactions is directly supplied by burning a portion of biomass with a sub-stoichiometric flow of oxygen in the reactor. A pressurised cryogenic air separation unit provides purified oxygen at 99.5% for the gasifier at 350 psia and 16°C. Purified oxygen is required rather than air to prevent introducing large quantities of nitrogen into the synthesis gas where it would act as an inert diluent.  Using a directly or indirectly hated gasifier will not influence the downstream processes.

In the VTT study (Hannula, et al., 2013) the front-end process train consists of the Ultra-Clean Gas (UCG) process, which has been the focus of VTT's biomass gasification R&D since 2006, with the methanol synthesis step.  Also, it includes hot-gas cleaning and gas conditioning into a process that is capable of converting solid biomass into synthesis gas which is clean enough to meet the requirements of the downstream synthesis island that includes catalytic synthesis, product recovery and upgrading sections. These processes are closely integrated with auxiliary equipment, which supports the operation of the plant. The auxiliary equipment includes a biomass dryer, an air separation unit (ASU), an auxiliary boiler and steam cycle. The synthesis gas is compressed to the pressure of the methanol loop in two steps: first to 20 bar prior acid gas removal followed by further compression to 80 bar for the methanol synthesis. Crude methanol is purified in a two-stage separation approach where in the first purification step dissolved gases and very light products are stripped off from the crude in a stabilisation column. In the second step, the remaining crude methanol is led to a concentration column, where it is separated to four streams: water drawn from the bottom, higher by-products from the centre tray, product methanol just under the rectifying section and light by-products purged from the top.

The Ecoinvent database (Jungbluth et al., 2007) is another source of information which provides an inventory model in the form of mainly mass and energy balances and includes raw materials and synthesis of methanol, (synthesis gas, processing energy, catalyst use, water for steam reforming). The hypothesis of this inventory model assumes that syngas comes both from fluidised bed and fixed bed technologies as both have been commercially used. Fixed bed gasification is more adapted to small scale decentralised applications whereas fluidised bed gasification is suitable for larger scale applications (e.g. production of synthesis fuels such as methanol, Fischer Tropsch (FT), DME etc.). For data of the methanol production step, it is assumed that the process of methanol from natural gas and methanol from syngas are similar, and therefore, some of the process stages are considered identical. In general, the Ecoinvent data are described as black boxes and only conceptual representation of the process is provided with no flowsheets given.

**DME:** For the case of DME in the PNNL report (Zhu, et al., 2011), the processing steps include the previous steps described for methanol synthesis (for direct and indirect cases) and one more step for the synthesis of DME. In this additional step, the purified methanol stream (~98% methanol) is sent to the DME reactor in which the methanol is catalytically dehydrated. High purity DME (99.85%) is then separated from water and unreacted methanol. Finally, methanol is separated and recycled back to the reactor, and water is sent to wastewater treatment. A portion of the unreacted methanol for recycling is split off and used for fuel gas to the steam reformer burners.

The study of VTT is based on one-step DME synthesis from syngas, using Haldor Topsøe's fixed-bed reactor design, and the recovery and distillation section for the preparation of fuel-grade dimethyl ether. The synthesis gas is compressed to reactor pressure in two steps: first to 20 bar prior acid gas removal step and then further to 60 bar prior inlet to the DME synthesis. The makeup gas is first mixed with unconverted gases from the recycle loop and preheated to 240 °C in heat exchange with the hot reactor effluent. The raw DME from the reactor, operated at 60 bar, is cooled against feed gas and then further with cooling water to separate DME, methanol and water by condensation. The resulting vapour stream is divided into recycle and purge streams. The recycle stream is recompressed and sent back to the reactor. Purge gas is sent to a methanol scrubber where residual DME is removed before sending the vent gases to an auxiliary boiler for combustion. The condensed raw product is sent to a DME distillation column where 99.9 wt. % purity DME is produced overhead at 46 °C and 10 bar.

## 2.2 Process inventory and cost data

Challenging points in terms of the collection of process information include the difficulty to access confidential industrial data and handling heterogeneous data sources. Thus, within this report an effort is made to present data in a homogeneous format (with an arrangement of process information in specific categories) to facilitate their use in the input to the analysis and modeling made in other project work packages. Process information is organised in inventory tables which arrange the process streams in input and output flows, which are characterised according to their role in the overall process (feedstock, waste, utility etc.) and therefore, facilitating further refinement in the technoeconomic and environmental analysis.

### 2.2.1 Mass and energy balances

The primary collected information obtained so far is typically characterised by a high variation in the degree of detail depending on the source. The more detailed sources provide simulation results from flowsheet models (i.e. mass and energy balances) and the composition of the process stream such as technoeconomic analysis studies of  (Zhu, et al., 2011; Zhu & Jones, 2009). Life Cycle Inventory (LCI) Databases are also an appropriate source of information, typically applying a format, according to ISO standards 14040 which facilitates the application of a Life Cycle Asessment  (LCA) method (e.g Ecoivent). However, LCI databases, due to confidentiality reasons of the edited processes, consider each process as a black box not providing any detailed presentation of process design characteristics, operating details, flow compositions and detailed flowsheets. Instead, they give basic principles for the conversion technology. Other literature sources provide only basic streams associated with the conversion of the feedstock to the desired product and process efficiency with respect to other by products.

A production pathway is typically comprised of several processing steps where intermediate products can be produced until the production of the final product. In the case of more than one processing step, information is available either in the unit process level of analysis where processing steps and their associated flows are described, separately or in an aggregated form. The former case gives an in-depth analysis of the most contributing stages in terms of energy and raw materials intensity, decomposition of capital investment costs, opportunities to study the effects from potential modifications of a process step and potential synergies among processes on heat and mass integration. When the information is reported in an aggregated form for all processing steps, it is obviously not possible to form an understanding on a component level. Energy requirements expressed as electricity or fuel consumption for heating are provided either as a “net” value, or as original values for consumption and production of energy utilities, separately. In this report, the priority is to present separate energy utility consumption and production within a process and when this information is not available then it is presented as net value.

In the current analysis, the inventory tables are compiled per process step (i.e. gasification step, methanol synthesis etc.) which can be considered as the “more aggregated level” of analysis. Thus, operating costs can be estimated on this basis. For each process step, further information for unit operations is available for a more accurate estimation of investment costs (CAPEX values).

The structure of the process inventory tables is as follows:

**Input streams**

*Feedstock:* the main material that is used as input (e.g. Wood biomass) within the process (e.g., gasification) and converted to the main product of a process step (e.g., syngas)

*Energy utility requirements:* Steam, natural gas, electricity required to cover heating demand or power loads within the process. If energy recovery measures are applied, heating demand is estimated as net demand, that is, the demand after energy recovery.

Chemicals and auxiliaries: Process auxiliaries, other than energy carriers, that participate in reactions or separation and purification steps to produce the product to a desired degree of purity.

*Water demand:* Water used in the process or for cooling purposes.

**Output streams**

*Products and co/by-products:* Product or co-products of the particular process step (e.g., syngas from gasification is co-produced with electricity which is derived from heat recovery in a steam turbine though exploitation of a high-pressure steam or from fuel spent gas in gas turbines).

*Waste streams (liquid or solid streams, air emissions):* Process streams which need treatment before their release in water bodies or disposed in the environment, they may be solid or liquid. According to their composition, liquid streams may be directed in a wastewater treatment plant either on site or in central municipal unit. Solid wastes may be directed to incineration units or to a landfill.

Data for methanol and DME obtained from the various data sources and organised in the form of inventory tables are given in Appendix A.

2.2.2 Cost data

The definition of the total project investment (CAPEX) (based on total equipment cost) as well as variable and fixed operating costs are described in the following paragraphs.

**Capital Cost (CAPEX)**

The capital cost estimates for the examined plant designs are given as the Total Overnight Capital (TOC) cost, which includes equipment, installation and indirect construction costs. The purchased cost of the equipment was calculated, then cost factors were used to determine the installed equipment cost.

These equipment costs can be considered as costs for either first or nth-of-a-kind of a kind plant. Considering these costs as representative for the first-of-its-kind plant corresponds to a more optimistic scenario with respect to future cost predictions. Vice versa, considering these costs as representative for the nth-of-its-kind plant corresponds to more conservative future cost estimations; in this case, to apply the learning curve framework one more parameter needs to be estimated, that is the point when the technology would reach the nth-of-a-kind plant maturity level. In this report, only the first scenario is presented, i.e., the corresponding investment costs are considered as the costs for constructing a plant with the current know-how, and since such plants are rather rare or not existent, this would be a first-of-a-kind plant. A more thorough analysis, including the second scenario will be presented in D3.6.

It is important to state that it is not always obvious what the difference is between nth-of-a-kind and first-of-a-kind plants. This, since the cost of the plants studied consists of major cost elements for which differences and relevance of learning differ. The three main cost estimates are purchase cost of equipment, civil engineering works and service (Thunman et al., 2019). Experiences from the detailed cost-breakdown of the GoBiGas project indicates that cost reductions can mostly be expected in the so-called Service element. With Service is meant the experience of assembling the different process steps into the complete unit. At a scale that is commercial – even if it is built as a first-of-a-kind plant – most reactors are commonly used in other application in petrochemical industries, refineries and energy plants. Therefore, they can be purchased commercially with little learning to be expected (e.g., in relation to other cost variations, such as related to variations in market conditions). Thunman et al. (2019) conclude that the most significant uncertainty factors for estimating production costs relate to trade conditions, the location of the installation and the local price of feedstock. Although this deliverable deals with capital costs, it is important to keep these conclusions in mind when assessing what total costs of advanced biofuels can be expected, as well as what will govern the uncertainty in cost estimates.

The indirect costs (non-manufacturing fixed-capital investment costs) and total installed cost (TIC) are estimated as a percentage of total purchased equipment costs, and total project investment (TPI, the sum of the TIC and the total indirect costs). The total project investment (TPI) is the sum of the total installed cost (TIC) plus the total indirect costs.

**Operating cost (OPEX)**

The operating costs are divided into variable and fixed operating costs. The following paragraphs discuss the operating costs including the assumptions and values for those costs.

*The Variable operating costs* include biomass, raw materials and chemicals, such as catalysts, biomass feedstock, fuel consumption, utilities (such as cooling water, boiler water, electricity etc.) and waste disposal. Quantities of raw materials used as feedstock and wastes produced are determined from inventory tables discussed in the previous paragraph and detailed in the Appendices.

*Fixed operating costs* do not depend on the productivity of the plant. These costs include labour and various overhead items, annual operating and maintenance costs, insurance etc.

Resulting costs

Tables 1 and 2 document the Investment cost of the methanol and DME plants and the total operating costs as obtained from literature. Disaggregated CAPEX values for each process component are provided in Appendix A.

*Table 1 Summary of Cost data of the methanol case as obtained from literature.*

| | PNNL (Zhu, et al., 2011) | PNNL (Zhu, et al., 2011) | VTT (Hannula, et al., 2013) | Ecoinvent |
|---|---|---|---|---|
| | Indirect gasification | Direct gasification | | |
| **Input Capacity (MW)** | 437 | 437 | 335 | |
| **Output Capacity (MW)** | 197 | 208 | 184 | |
| **Capital Cost, Total Project Investment** | | | | No data |
| **MEuro 2018** | 234 | 356 | 390 | |
| **Euro/kW methanol** | 1189 | 1708 | 2117 | |
| **Operating Cost** | | | | |
| **Euro/kg methanol (2018)** | 0.20 | 0.21 | 0.25 | |
| **Euro/MWh methanol** | 35.2 | 38.1 | 45.3 | |
| **Fixed cost (% of Operating Cost)** | 22 | 24 | Not known | |

*Table 2 Summary of Cost data of the DME case as obtained from literature.*

| | PNNL (Zhu, et al., 2011) | PNNL (Zhu, et al., 2011) | VTT (Hannula, et al., 2013) |
|---|---|---|---|
| | Indirect gasification | Direct gasification | |
| **Input Capacity (MW)** | 437 | 437 | 335 |
| **Output Capacity (MW)** | 207 | 194 | 179 |
| **Capital Cost, Total Project Investment** | | | |
| **MEuro 2018** | 226 | 354 | 401 |
| **Euro/kW DME** | 1095 | 1828 | 2233 |
| **Operating Cost** | | | |
| **Euro/kg DME (2018)** | 0.25 | 0.26 | 0.34 |
| **Euro/MWh DME** | 34.7 | 35.4 | 46.8 |
| **Fixed cost (% of Operating Cost)** | 24 | 22 | Not known |

# 3. Technology learning

The learning curve (LC) is an important tool for estimating technical change and informing policy decisions related to technologies. For many products and services, unit costs decrease with increasing experience. The idealised pattern describing this kind of technological progress in a regular way is referred to as a learning curve, progress curve, experience curve, or learning-by-doing (Dutton and

Thomas, 1984; Argote and Epple, 1990; Argote, 1999, (Chase, 2011) or Henderson Curve since Bruce Henderson, founder of the Boston Consulting Group, fully articulated the concept in 1968 (Henderson, 1968). In its most common formulation, unit costs decrease by a constant percentage, called the learning rate, for each doubling of experience (e.g. doubling the number of produced units).

The role of technology learning in the reduction of the unit costs of production with accumulating production has been the subject of considerable study. The concept has its origins in observations at the plant level for aero manufacturing where a uniform decrease in labour inputs accompanied each doubling of cumulative production (Wright, 1936). The systematic link between decreasing unit production costs and cumulative volume has since found empirical support in a wide range of products and has been extended to industry sectors and technologies.

Within energy systems solar PV technology has been applied successfully in which there obviously has been many panels produced over many years, making it possible to plot learning curves.

## 3.1 Theoretical framework

Learning curves describe historic trends that may be extrapolated to forecast future cost reductions. This possibility is frequently used by individual corporations, energy modellers and policy makers (Neij et al., 2003).

### 3.1.1 Single factor approach

The single factor learning curve, in which production costs are reduced by a constant fraction for each doubling of cumulative production, relates the unit cost development of a technology to the accumulated learning, often represented by accumulated production. It is illustrated by plotting a reduction in technology costs against its accumulated production. For example, in the power generation sector (Wiesenthal, et al., 2012), it can be represented by a plot of specific installation costs versus the accumulated installed capacity of the involved technology.

Learning curve studies have experimented with a variety of functional forms to describe the relationship between cumulative capacity and costs (Yelle, 1979). The most common representation is to plot the curve in a log-log plot, because cost data from several technologies – such as solar PV panels – show a straight line in such plots representing the learning rate. Thus, the central parameter in the learning curve model is the exponent defining the slope of a power function, which appears as a linear function when plotted on a log–log scale. This parameter is known as the learning coefficient (b) and can be used to calculate the Progress Rate (PR) and Learning Rate (LR) as shown below. Thus, technology learning is commonly modelled as a learning curve which plots unit costs against cumulative volume of production.

This single factor relationship is commonly expressed as:

$$C(Q_t) = C(Q_0) \cdot [\frac{Q_t}{Q_0}]^{-b} \qquad (1)$$

*where Qt is the cumulative production,*
*b is the positive learning parameter,*
*C ($Q_t$) is the unit cost of production at $Q_t$, (in the more general form (i.e. operating cost and annualized investment cost)*
*C ($Q_0$) and $Q_0$ are respectively the cost and cumulative production at an arbitrary starting point.*

It should be pointed out that log-log representations are highly "forgiving" in the sense that they may give the illusion of a straight line in spite of merely showing a steep initial cost decrease followed by scattered costs, once costs have reached a certain level. Thus, care should be taken when interpreting such curves.

The definition of the 'unit' may vary: in many cases a unit is a product (for example a car or a PV panel). In relation to energy technologies, more often the unit is the unit of capacity (Watt) of the energy technology produced or the unit of electricity produced (kWh). The experience curve concept has been used and applied for many different energy technologies; for an overview see (McDonald and Schrattenholzer, 2001).

The associated Learning Rate (LR) is defined as the relative cost reduction in unit production costs for each doubling of cumulative production:

$$LR = 1 - 2^{-b} \qquad (2)$$

Or 100 × ($1-2^{-b}$) when the learning rate is expressed as a percentage.

$$PR = 2^{-b} \text{ and } LR = 1 - PR \qquad (3)$$

PR denotes the Progress Rate, linked to the unit cost decline with each doubling of cumulative production. For example, a PR of 0.8 implies that after one doubling of cumulative production, unit costs are reduced to 80% of the original costs, i.e. a 20% cost decrease.

Typical industries possess b values ranging from 0.15 to 0.5, corresponding to a PR of 90% to 70%, respectively.

### 3.1.2 The extension to multi-factor approach

Two factor and multifactor modelling approaches to technology learning have been developed, but the single factor model is commonly used to represent endogenous technical change in energy-economic modelling (Wiesenthal et al., 2012). Learning rates relate technology improvement or cost reduction to other parameters in the model and play an important role in energy environment modelling, notably long-term integrated assessment models (Kahouli-Brahmi, 2008; Hayward and Graham, 2013).

A variety of multi-factor learning models can be found in literature. For example, such models explicitly incorporate parameters such as R&D spending knowledge spillovers, increased capital investments, economies-of-scale, changes in input prices, labor costs, efficiency improvements, and other public policies (Azevedo, o.a., 2015; Yeh, o.a., 2012).

The most prevalent multi-factor model for energy technologies is a "two-factor learning curve" where the key drivers of cost reduction are assumed to be the cumulative expenditure for R&D as well as the cumulative installed capacity or production of the technology (Jamasb, 2007).

The expansion of Eq. (1) to explicitly include the effect of cumulative R&D expenditures is:

$$\log C = \alpha + b_{lbd}(\log (Q_t/Q_0)) + b_{lbr}(\log R) \qquad (4)$$

*where $b_{lbd}$ is the learning-by-doing parameter,*
*$b_{lbr}$ is the learning- by-researching (LBR) parameter,*
*R is the cumulative R&D investment or knowledge stock,*
*α is the specific cost at unit cumulative capacity and unit knowledge stock,*
*and C and $Q_t$, $Q_0$ have the same definitions as in Eq. (1).*

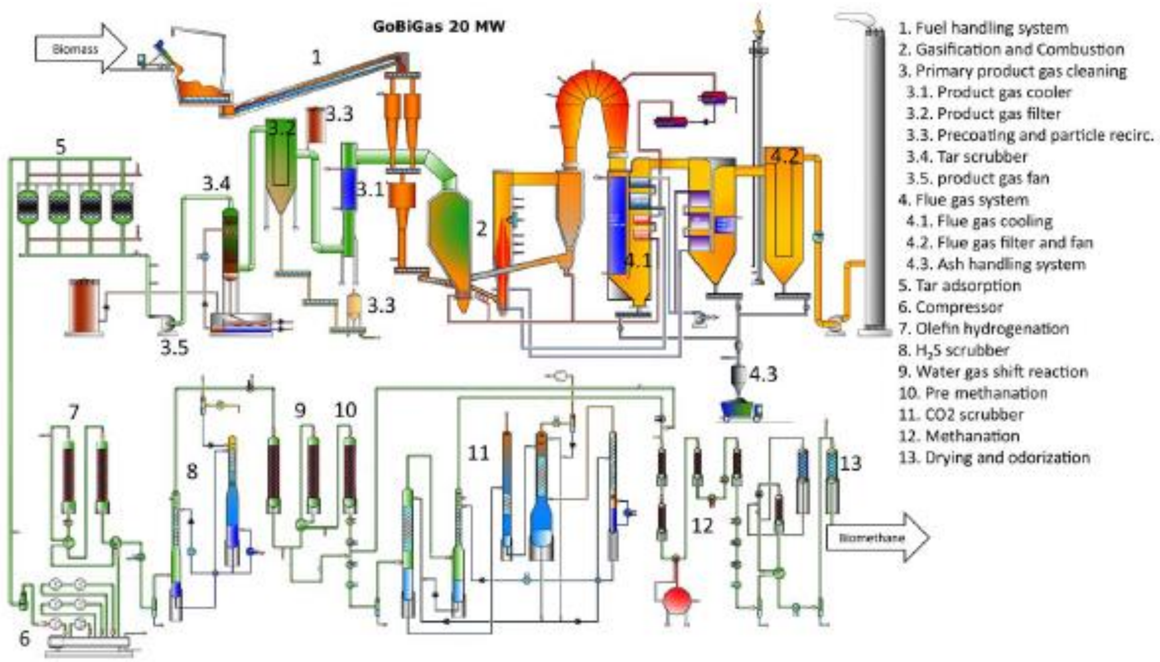


*Figure 1. A schematic of the GoBiGas plant with major process steps included (Thunman et al., 2018).*

## 3.2 Component learning

The component learning approach (Ferioli et al., 2009) extends the single factor model by treating the cost of a technology as a sum of the costs of its individual components (i.e. unit operations in a process). Such an approach would be of importance when applying learning to biomass processes which obviously consists of a certain number of reactors, each having different maturity. Figure 1 shows a (simplified) process scheme of the GoBiGas gasifier for SNG production. It should be obvious from Figure 1 that any learning approach must consider the multi component aspect if resulting in any meaningful way of trying to predict future cost development of an entire process. The component learning approach allows technology improvement to occur at different rates for different components. Thus, component learning is a way of disaggregating the technology learning process into separate parts (e.g. plant and equipment, operating costs, etc.) and building a composite learning rate based on analysis of the separate components (Ferioli et al., 2009). Assuming that the cost of each component decreases over time according to a power law relation as a result of learning, then the technology learning relationship may be expressed as follows (where the index *i* represents a given cost component):

$$C(Q_t) = \sum C(Q_{0i}) \cdot [\frac{Q_t}{Q_0}]^{-b(i)} = C_{01}[\frac{Q_{t1}}{Q_{01}}]^{-b(1)} + C_{02}[\frac{Q_{t2}}{Q_{02}}]^{-b(2)} + \cdots . + C_{0n}[\frac{Q_{tn}}{Q_{0n}}]^{-b(n)} \quad (5)$$

*where b(i) is positive learning parameter for component i,*

*$C(Q_t)$ is the unit cost of production at cumulative production $Q_t$,*

*$Q_0$ is the cumulative production at an arbitrary starting point,*

*$C_{0i}$ is the cost and $Q_{0i}$ is the cumulative production of component i at an arbitrary starting point.*

It should be kept in mind that (as mentioned in the introduction to this report) for advanced biofuel production, a large potential in learning is in the assembly of the components, as this is what is new and related to the particular application. As for the components the scale-up of the process opens up for using components that are in commercial operation in petrochemical, power and refinery industries with less potential learning to be expected.

# 3.3 Learning rates of various energy technologies

In the energy field, the experience curve concept is so far used mostly to describe learning for modular products, such as wind turbines, fuel cells and solar photovoltaic (PV) modules. Learning effects have been also investigated, for instance, for coal-fired power plants (Joskow and Rose, 1985) and light water reactor nuclear power plants (Lester and McCabe, 1993). Many integrated energy assessment models, however, only use an estimated Progress Rate for various plant type technologies using fuels (Kouvaritakis et al., 2000). Examples are the development of natural-gas-fired combined cycle gas turbine power plant (Claeson Colpier and Cornland, 2002) and large-scale production of ethanol from sugarcane in Brazil (Goldemberg, 2004).

Table 3 provides a summary of learning rates for several technologies (Rubin et al., 2015). When comparing the values among the technologies, it is obvious that the solar PV technology and onshore wind have been progressing well compared to the other technologies showing the highest values of LR. Technologies that are currently most prevalent and mature are power plants using fossil fuels (coal and natural gas), nuclear energy, and hydropower.

It should be noted that the range of learning rates reported for each technology varies considerably, from a factor of two (e.g., 5.6% to 12% for pulverised coal plants) to more than an order of magnitude (2.5% to 20% for integrated gas combined cycle with carbon capture and storage). In some cases, the reported range includes negative as well as positive values, indicating that costs have risen as well as declined with increased deployment.

*Table 3. Range of reported one-factor learning rates for electric power generation technologies (Rubin et al., 2015).*

| Technology | Learning rate (%) | Mean LR | Time period |
|---|---|---|---|
| **Coal** | | | |
| PC | 5.6 – 12 | 8.3% | 1902 – 2006 |
| PC+CCS | 1.1 – 9.9 | | Projections |
| IGCC | 2.5 – 16 | | Projections |
| IGCC+CCS | 2.5 – 20 | | Projections |
| **Natural gas** | | | |
| NGCC | -11 – 34 | 14% | 1980 – 1998 |
| Gas turbine | 10 – 22% | 15% | 1958 –1990 |
| NGCC þ CCS | 2 - 7% | | |
| **Nuclear** | Negative – 6 | | 1972 – 1996 |
| **Wind** | | | |
| **Onshore** | -11 – 32 | 12% | 1979 – 2010 |
| **Offshore** | 5 - 19% | 12% | 1985 – 2001 |
| **Solar PV** | 10 – 47% | 23% | 1959 – 2011 |
| **Biomass** | | | |
| **Power generation** | 0 – 24% | | 1976 – 2005 |
| **Biomass production** | 20 - 45% | | 1971 – 2006 |
| **Geothermal** | - | - | |
| **Hydroelectric** | 1.4 % | 1.4% | 1980 – 2001 |

*A negative progress ratio indicates that costs are increasing. More of this will follow in a later section. (PC: Pulverized Coal, CCS: Carbon Capture and Storage, NGCC: Natural Gas Combined Cycle, IGCC: Integrated Gas Combined Cycle)

# 3.4 Electricity from biomass

Values for progress and learning rates (PR and LR) are given for various electricity production technologies using biomass as a motivation for the analysis of biofuel processes and to have some reference values for the cases of methanol and DME. Table B1, in Appendix B, provides an overview of studies conducted on technological learning in bioelectricity systems. Experience curves for biomass power plants are difficult to construct as there are variations in the characteristics of such plants, concerning the type of technology used, plant size and the type of biomass feedstock used. To some extent, this difficulty to derive experience curves is due to lack of (detailed) data. Most work on biomass-based power generation has focused on fluidised bed combustion for combined heat and power (CHP) and the production of biogas, reporting values for learning rates either referring to investment costs or to total production costs.

Koornneef et al. (2007) use global data on the capital costs of fluidised bed combustion plants from 1976 to 2005 and find learning rates ranging from 7% to 10%. The same values are reported from Junginger et al. (2006) for fluidised bed boiler plants built on a global level, where progress rates (PRs) for the price of entire plants range between 90–93% (7-10%% cost reduction), i.e., typical for large plant-like technologies.

Similarly, Junginger et al. (2006) find that electricity from biofueled CHP-plants yields PRs of 91–92%. Junginger et al. (2006) also evaluate decreases in the investment costs of bio digesters used to produce biogas in Denmark. For the period from 1988 to 1998, they found a learning rate of 12% due to a higher yield of biogas (by adding organic waste), an increase in plant availability, and a reduction in operating and maintenance costs. Looking at the total cost of biogas production in Denmark (in units of euros in 2002/Nm3), a PR of 85% from 1984 to the beginning of 1990 is reported, which then levels to approximately 100% until 2002.

Cost trends for the production and transport of biomass are also of interest as they contribute significantly to the total cost of electricity or biogas production. Studies examining crop based feedstock production costs, including sugarcane (Brazil), corn (U.S.), and rapeseed (Germany), suggest that feedstock production costs have declined over time. These studies report learning rates associated with feedstock costs in the range of 20–45% (although this “learning” may simply be an effect of increased reactor size, rather than improved technology). Also D2.2. investigates on cost reduction potential of various lignocellulosic energy crops. Learning effect has a cost reduction potential of 25% regarding short rotation willow (Rosenqvist et al., 2013).

## 3.5 Biofuels

Not only the variety of biofuel production system options available, but also the variable cost and performance of these systems are all factors which make it difficult to create general learning curves for these technologies. Additionally, for the biomass production stage this variation is significant as crop yields for example depend on climate, soil conditions and agricultural management. Table 4 provides an overview on studies conducted in regard to technological learning in biofuel production including sugar cane, corn ethanol and rapeseed-diesel and the assumed progress ratios in Green-X for 1st and 2nd generation biofuels.

For 2nd generation biofuels, there is currently not sufficient empirical data available to fit the learning curve and determine its parameters, due to the limited amount of installations that are deployed up to now. From 2015 onwards, a progress rate of 90% is assumed for both biofuel production systems (Source https://green-x.at/).

For the REFUEL project (2008), de Wit et al. (de Wit, Junginger et al. 2009) developed an alternative approach to account for technological learning of advanced biofuels with a multi-factor learning curve approach. This learning model includes a scale dependent and a scale independent learning factor. The scale dependent factor is confined to a minimum time before the capacity of a single plant can double (3-5 years) and a maximum market share of a single plant (5%). In the work of de Wit et al. (de Wit, Junginger et al. 2009) the scale-independent progress rate was assumed to be 98-99%.

For Brazilian sugarcane, van den Wall Bake et al. (2009) find a learning rate of 32% based on a composite of production costs from 1975 to 1998 and sales price from 1999 to 2004. Sale prices were used as a proxy for costs after 1999 because by that time the market was fully deregulated, and prices tend to track costs reasonably well in well-established markets (van den Wall Bake et al., 2009). Cost reductions for soil preparation, crop maintenance, and rent were strongly influenced by increasing agricultural yields and harvesting productivity. Cost reduction potentials referring to lignocellulosic cropping schemes are assessed in D2.2. In another study, Hettinga et al. (2009) examine the costs of U.S. corn production between 1985 and 2000 and find a learning rate of 45%. Higher corn yields and increasing farm sizes were partly responsible for decreasing costs. A study of German rapeseed production by Berghout (2008) finds a learning rate of 19.6% based on production and cost data from 1971 to 2006. Cost reductions are attributed to improved varieties of rapeseed, higher crop yields, a reduction in fertilizer costs, and lower fertilizer usage (but also due to that, units have simply become larger, reducing the specific cost). The values mentioned in this paragraph refer mainly to total production costs. For this reason, this information should be clarified before using them in projections of investment costs. The estimations made in this report refer to capital costs so corresponding LR values derived from data of capital costs versus cumulative capacity should be used.

*Table 4 Overview of Progress Rates (PRs) for 1st and 2nd generation biofuels in Green-X and published in literature (Faaij and Junginger 2010) (Source [https://green-x.at/](https://green-x.at/) )*

| Reference | PR (%) | Time frame | Price data region | Capacity |
|---|---|---|---|---|
| **1st generation biofuels** | | | | |
| **Green-X** | | | | |
| **Biodiesel** | 97.5 | <2010 | Global | Global |
| | 95 | >2010 | Global | Global |
| **Van der Wall Bake et al. 2009** | | | | |
| **Sugar cane cultivation (tonne sugar cane)** | 68(±3) | 1975-2003 | Brazil | Brazil |
| **Sugar cane ethanol plant (investment + O&M)** | 81(±2) | 1975-2003 | Brazil | Brazil |
| **Ethanol from sugar cane (final energy)** | 80(±2) | 1975-2003 | | |
| **Goldemberg et al. 2004** | | | | |
| **Ethanol from sugar cane (final energy)** | 93/71 | 1980-1985 | Brazil | Brazil |
| **Hettinga et al. 2009** | | | | |
| **Corn cultivation** | 55((±0.02) | 1975-2005 | USA | USA |
| **Corn ethanol plant (investment + OM)** | 87(±1) | 1975-2005 | USA | USA |
| **Corn ethanol** | 82(±1) | 1975-2005 | USA | USA |
| **Berghout 2008** | | | | |
| **Rapeseed cultivation (seed)** | 80.4(±1) | 1993-2007 | Germany | Germany |
| **Biodiesel plant (investments)** | 97.6(±1) | 1993-2007 | Germany | Germany |
| **Rapeseed biodiesel (final energy)** | 97.7(±1) | 1993-2007 | Germany | Germany |
| **2nd generation biofuels** | | | | |
| **Green-X** | Expert judgment | <2015 | Global | Global |
| **Lignocellulosic ethanol/BtL** | 90% | >2015 | Global | Global |

# 4. Application of learning curve theory in case studies

The selected fuels analysed in this report, methanol and DME, are already produced and used at commercial scale and can be generated from syngas as an intermediate. As background to the understanding of the learning process of these fuels and of syngas, brief description of their status is provided below.

**Methanol** is produced on a large commercial scale from natural gas (~90 million ton per year (reference year 2018)). The current (2017) market price, which mainly depends on the price of natural gas, is around 0.41 $ per kg (Detz, et al., 2018). Methanol is the base chemical for the synthesis of formaldehyde, acetic acid, and methyl tert-butyl ether (MTBE). For a few years methanol has also been increasingly used for fuel applications, by direct use or blended into gasoline, to produce dimethyl ether (DME) or directly by blending it with gasoline. A route for producing renewable methanol is to use H2, made by electrolysis, together with CO2 in a methanol synthesis reactor. In the approach for the analysis in the current deliverable, a syngas plant (SP) is combined with a methanol plant (MP). An increasingly discussed alternative route for producing renewable methanol is to use $H_2$, from electrolysis, together with $CO_2$ in a methanol synthesis reactor.

**Dimethyl Ether (DME):** The present commercial use of DME is mainly as an aerosol propellant along with propane and butane as a green replacement for the chlorofluoro-hydrocarbons which were outlawed because of their detrimental impact on the ozone layer (through the 1987 Montreal Protocol). DME is an environmentally benign, non-toxic, biodegradable product with physical properties similar to LPG. Global DME annual production capacity is approximately 10 million metric tons with a remarkable increase from the 200,000 metric tons market in the early 2000s (Fleisch, et al., 2012).

**Synthesis gas, or syngas**, is a common feedstock used to produce various bulk chemicals and renewable fuels. Syngas is usually produced by steam reforming of methane or partial oxidation of hydrocarbon feedstocks (fossil fuels or biomass). Its current production costs are estimated at around 0.19 $ per kg (Detz, et al., 2018). Syngas is used in processes like methanol and DME manufacturing and FT synthesis of gasoline, diesel and waxes. A pathway to make renewable syngas can provide the principal building block for the renewable production of many fuels and chemicals. Although various possibilities exist, we analyse here the biomass gasification pathway as described in Deliverables 3.2 and 3.4.

There are no plants available of industrial size, which produce advanced transportation fuels. The only existing gasification units of industrial size are such which just produce a product gas which is burnt in a boiler. See International Energy Agency (IEA) Bioenergy Task 33—Thermal Gasification of Biomass database, (Bioenergy Task 33 IEA) for a list of such plants and smaller demonstration plants. The only implemented plant to produce syngas at a larger demonstration scale is the GoBiGas 20MW indirect gasification plant, but this plant was taken out of operation due to market constraints (Thunman et al., 2018).

## 4.1 Data collection for learning curve models

The multi-component approach of the learning theory framework is applied in this report. Table 5 gives a decomposition of the production pathway of methanol and DME into their processing steps (e.g. syngas step, methanol step, auxiliary equipment and DME) with each step subdivided into the main unit operations. Colours are used to rate each unit operation with respect to if it can be considered as “more mature”, as indicated by Green or “less mature” as indicated by Red.

Table 6 gives the LR, Cumulative Installed Capacity (CIC) and Cumulative Annual Growth Rate (CAGR) values for the components corresponding to the unit operations in Table 5. The ideal case is when these values are provided for each unit operation but usually this information is given for the entire process (e.g. methanol, syngas etc.).

According to the study of (Detz, et al., 2018) for methanol plants and FT plants, no data for learning is available. In this deliverable we follow their approach to base the LR for these technologies by estimating their position in the Gaussian distribution (obtained by Ferioli et al., (2009) from 108 studies from 22 industrial sectors, among which are the electronics, machine tools, paper- making, steel and automotive industries. Additionally, in the study of Detz, et al. (2018), it is stated that more mature technologies (such as methanol and FT plants) generally have a lower learning rate (left of the mean value in the Gaussian). This justifies the choice of LR = 10% whereas for novel technologies a higher learning rate of 20%, around the mean of the distribution is proposed. For this reason, in this deliverable the value of 5% and 15% are selected for methanol and gasification steps, respectively. Values of LR for DME (from syngas and from methanol) are considered the same as the methanol synthesis step. It should be noted that in the study of Daugaard, et al. (2014) values of LR for biorefineries are given as aggregated expressions i.e. Gasification to methanol as shown in Table 6. In this study LR of 5%, (which includes the less mature gasification step) is given for the entire path. This is propelled by the assumption that gasification and cellulosic ethanol technologies were assumed to have plant-learning rates comparable to current large scale manufacturing enterprises, such as IGCC and coal power plant technologies (5%); fast pyrolysis and grain ethanol were assumed to have learning rates comparable to current small-scale facilities, such as Brazilian sugarcane to ethanol (20%). This differs somewhat to the study of (Detz, et al., 2018) where for the mature methanol a minimum value of 0.1 is attributed and less mature technologies have values around 0.2) This shows that there is a significant level of uncertainty in these values which calls for sensitivity analysis based on ranges of these values and thus for the respective CAPEX reduction calculations (together of course with other factors which are also uncertain, such as annual growth rate and DF).

*Table 5 Analysis of the production path of methanol and DME in processing steps and highlighting of "more mature" and "less mature" process components (unit operations) (red & green colour correspond to less mature and more mature technologies, respectively).*

| **Methanol** | | | | | **DME** | | |
|---|---|---|---|---|---|---|---|
| | **PNNL** | **PNNL** | **VTT** | | **PNNL** | **PNNL** | **VTT** |
| | **Indirect gasification** | **Direct gasification** | | | **Indirect gasification** | **Direct gasification** | |
| Auxiliary equipment | | | | **Auxiliary equipment** | | | |
| | Air separation unit | Air separation unit | Buildings | | Air separation unit | Air separation unit | Buildings |
| | Feed prep and drying | Feed prep and drying | Oxygen production | | Feed prep and drying | Feed prep and drying | Oxygen production |
| | Remainder off-site battery limits | Remainder off-site battery limits | Feedstock pretreatment | | Remainder off-site battery limits | Remainder off-site battery limits | Feedstock pretreatment |
| Gasification step | | | | **Gasification island** | | | |
| | Gasification with tar reforming, heat recovery, scrubbing | Gasification with tar reforming, heat recovery, scrubbing | Gasification | | Gasification with tar reforming, heat recovery, scrubbing | Gasification with tar reforming, heat recovery, scrubbing | Gasification |
| | Syngas cleanup & compression | Syngas cleanup & compression | Hot-gas cleaning | | Syngas cleanup & compression | Syngas cleanup & compression | Hot-gas cleaning |
| | | | CO shift | | | | CO shift |
| | | | Syngas cooling | | | | Syngas cooling |
| | | | Compression | | | | Compression |
| | | | Acid gas removal | | | | Acid gas removal |
| **Power production** | | | | **Power island** | | | |
| | Steam system and power generation | Steam system and power generation | Steam system and power generation | | Steam system and power generation | Steam system and power generation | Steam system and power generation |
| **Methanol step** | | | | | **Methanol step** | | **Single-step DME (Topsoe)** |
| | Methanol synthesis & purification | Methanol synthesis & purification | Syngas compressor | | Methanol synthesis & purification | Methanol synthesis & purification | Syngas compressor |
| | | | MeOH synth+dist.+compression | | **DME synthesis** | | DME synth + dist. |
| | | | | | DME synthesis and separation | DME synthesis and separation | |

The production capacity in 2018 of methanol and DME is taken as their Cumulative Installed Capacity (CIC). In addition to a low LR, also the Cumulative Annual Growth Rate (CAGR) is low for mature commercial technologies such as methanol synthesis (7%). For DME the respective value of the fossil-based production is 8% whereas the value of the bio-based DME is 11%. These growth rates are relatively lower than for other emerging technologies such as Photoelectrochemical $H_2O$ splitting (PEC) in the work of Detz, et al., (2018) with a value of CAGR of around 30%.

For all learning curves, we adopt three different scenarios: a base case, an optimistic projection, and a conservative projection. The base case represents an intermediate scenario that starts from the current average cost value. Central values for LR, CIC, and CAGR are included in Table 6; these determine the future progress in these costs. Although unforeseen developments may always happen, the uncertainty based on technology maturity and complexity of the fuel production route is to a large extent covered by the ranges we use (following the justification of (Detz, et al., 2018)). The extremes in these ranges lead to either the more optimistic or the more conservative cases. In the optimistic projection, the lowest current cost estimate is coupled with the same CIC as for the base case, although this time on the basis of a high LR and a high CAGR. The conservative projection starts from a high current cost level and the CIC from Table 6, while here we apply a low LR and low CAGR.

To simulate a decreasing CAGR over time, we introduce a decline factor (DF) as also proposed by Detz, et al. (2018). A DF of 1 indicates that the CAGR remains constant over time. If DF > 1 (not used in this article), the CAGR increases over time, while DF < 1 (used here) results in a gradually declining CAGR. The DF of the base case (0.96 in most cases) is chosen exactly in between that of the optimistic (0.99 in most cases) and conservative (0.93 in most cases) projections. The LR and CAGR figures for the various systems are derived from historical data reported in the literature and their ranges considered for the development of the scenarios in the sensitivity analysis are obtained from assuming ±30% deviation from the original values.

*Table 6 Values of LR, CIC and CAGR for each process step used for the cost reduction projections (In the next version parameters will be given per unit operation and not to the entire process step).*

| Technology | Value | Unit | Region | Reference |
|---|---|---|---|---|
| **Learning rate (LR)** | | | | |
| **Syngas (gasification step)** | 0.15 (±0.05) | | Global | (Detz, et al., 2018) and according to the analysis of (Daugaard, et al.) |
| **Methanol (methanol synthesis step)** | 0.05 (±0.02) | | Global | (Detz, et al., 2018) |
| **DME (DME synthesis step)** | 0.05 (±0.02) | | Global | (Detz, et al., 2018) |
| **Cumulative installed capacity (CIC)** | | | | |
| **Syngas** (used in the sub-steps of gasification island with the lowest maturity level according to Table 5)* | 20 | MW | Sweden, GobiGas (in spite of that it was taken out of operation, we take the value from this unit it is the only demonstration plant of large scale (20 MW) that produced syngas | (Thunman et al., 2019) |
| **Methanol (methanol synthesis step)** | 90 | Million tons | Global | (Alvarado, 2016) |
| | 65,596 | MW | Global | |
| **DME (DME synthesis step)** | 10 | Millions tons | Global | (Fleisch, et al., 2012) |
| | 7,288 | MW | Global | |
| **Cumulative annual growth rate (CAGR)** | | | | |
| **Syngas (**used in the sub-steps of gasification island with the lowest maturity level according to Table 5)**)** | 0.11 (±0.03) but this is for fossil | Global | | (Research and Markets) |
| **Methanol (methanol synthesis step)** | 0.07 (±0.02) | Global | | (Detz, et al., 2018) |
| **DME (DME synthesis step)** | 0.08 (±0.03) | | | (Singh, et al.) |

**This value was selected as any other plant found in literature was significant smaller in capacity compared to the GoBiGas (Arvidsoon M. 2014). It can be questioned if it is reasonable to use CIC values in cases where there are only a very small capacity installed (e.g. a few MW).*

## 4.2 Application in the cases of methanol and DME production

Tables 7 and 8 provide a summary of the results for cost reductions, based on the multi-component version of the learning curves theory, for methanol and DME, respectively and for each reference found in literature, separately. The methodological framework was applied separately for each separation step for which the parameters of Eq. 5 are available.

The ranges of CAPEX and % reduction given in Tables 7 and 8 correspond to the conservative (maximum CAPEX, minimum % reduction) and the optimistic scenarios (minimum CAPEX, maximum % reduction), respectively. Appendix C gives detailed results for CAPEX reduction per component.

*Table 7 Summary of estimated cost reductions for methanol production*

| **Methanol** | | | | |
|---|---|---|---|---|
| **Indirect gasfication (Zhu, et al., 2011)** | | | | |
| | 2018 | 2020 | 2030 | 2050 |
| **Auxiliary equipment** | 40 | 39 | 38 | 35 |
| **Gasification** | 130 | 117 | 96 | 65 |
| **Power island** | 28 | 27 | 26 | 25 |
| **Methanol synthesis** | 37 | 37 | 35 | 33 |
| **Total CAPEX (Meuro)** | **234** | 220 | 195 | 157 |
| **% Reduction** | 0% | 6 | 16% | 33% |
| ***Sensitivity analysis*** | | | | |
| **Total CAPEX (Meuro) (Min, Max)** | | 210, 228 | 191, 196 | 121, 195 |
| **% Cost Reduction (Min, Max)** | | 10%, 3% | 27%, 8% | 48%,17% |
| **Direct gasification (Zhu, et al., 2011)** | | | | |
| | 2018 | 2020 | 2030 | 2050 |
| **Auxiliary equipment** | 73 | 72 | 69 | 65 |
| **Gasification** | 210 | 190 | 156 | 105 |
| **Power island** | 34 | 33 | 32 | 30 |
| **Methanol synthesis** | 40 | 39 | 38 | 35 |
| **Total CAPEX (Meuro)** | 356 | 334 | 295 | 234 |
| **% Reduction** | 0% | 6% | 17% | 34% |
| ***Sensitivity analysis*** | | | | |
| **Total CAPEX (Meuro) (Min, Max)** | | 317, 346 | 256, 328 | 177, 294) |
| **% Cost Reduction (Min, Max)** | | 3%, 11% | (8%, 28% | 8%, 28% |
| **Fluidized- bed gasification VTT (Hannula, et al., 2013)** | | | | |
| | 2018 | 2020 | 2030 | 2050 |
| **Auxiliary equipment** | 116 | 114 | 110 | 103 |
| **Gasification** | 177 | 165 | 144 | 113 |
| **Power island** | 27.3 | 26.4 | 24.6 | 27.3 |
| **Methanol synthesis** | 67 | 65 | 61 | 67 |
| **Total CAPEX (Meuro)** | **389** | 374 | 346 | 301 |
| **% Cost Reduction** | 0% | 4% | 11% | 23% |
| ***Sensitivity analysis*** | | | | |
| **Total CAPEX (Meuro) (Min, Max)** | | (363, 383 ) | (320, 370) | (258 ,346 ) |
| **% Cost Reduction (Min, Max)** | | (2%, 7%) | (5%, 18%) | (11%,34% ) |

*Table 8 Summary of estimated cost reductions for DME production*

| DME | | | | |
|---|---|---|---|---|
| **Indirect gasfication (Zhu, et al., 2011)** | | | | |
| | 2018 | 2020 | 2030 | 2050 |
| **Auxiliary equipment** | 40 | 39 | 38 | 35 |
| **Gasification** | 125 | 113 | 93 | 63 |
| **Power island** | 28.1 | 27.2 | 25.3 | 28.1 |
| **Methanol synthesis** | 24 | 24 | 23 | 22 |
| **DME synthesis** | 8 | 8 | 8 | 7 |
| **Total CAPEX (Meuro)** | 226 | 212 | 189 | 152 |
| **% Reduction** | 0% | 6% | 17% | 33% |
| ***Sensitivity analysis*** | | | | |
| **Total CAPEX (Meuro) (Min, Max)** | | 202 ,220 | 165 ,209 | 116 ,188 |
| **% Cost Reduction (Min, Max)** | | 3%, 10% | 8% ,27% | 17%, 49% |
| **Direct gasification (Zhu, et al., 2011)** | | | | |
| | 2018 | 2020 | 2030 | 2050 |
| **Auxiliary equipment** | 73 | 72 | 70 | 65 |
| **Gasification** | 216 | 195 | 160 | 108 |
| **Power island** | 35 | 34 | 33 | 31 |
| **Methanol synthesis** | 23 | 22 | 22 | 20 |
| **DME synthesis** | 8 | 8 | 7 | 7 |
| **Total CAPEX** | 354 | 331 | 292 | 230 |
| **% Reduction** | 0% | 6% | 18% | 35% |
| ***Sensitivity analysis*** | | | | |
| **Total CAPEX (Meuro) (Min, Max)** | | 314,344 | 252 ,325 | 192,291 |
| **% Cost Reduction (Min, Max)** | | 3% , 11% | 8% ,29% | 18%, 51% |
| **Fluidized- bed gasification VTT (Hannula, et al., 2013)** | | | | |
| | 2018 | 2020 | 2030 | 2050 |
| **Auxiliary equipment** | 116 | 114 | 110 | 103 |
| **Gasification** | 177 | 165 | 145 | 113 |
| **Power island** | 28 | 28 | 27 | 25 |
| **DME synthesis** | 79 | 78 | 74 | 69 |
| **Total CAPEX (Meuro)** | 400 | 385 | 356 | 309 |
| **% CostReduction** | 0% | 4% | 11% | 23% |
| ***Sensitivity analysis*** | | | | |
| **Total CAPEX (Meuro) (Min, Max)** | | 373 ,394 | 327, 380 | 261, 356 |
| **% Cost Reduction (Min, Max)** | | 2% ,7%) | 5%,18% | 11%,35% |

# 5. Conclusions

This report presents a methodological framework that assesses the potential degree of implementation of biomass processes in the short and long term, considering maturity and cost aspects. The first estimations are based on two case studies: methanol and DME production from syngas as an intermediate product as they are already available for commercial use fossil fuel resources.

The framework applied within this report has adopted the learning curve theory. Although there are large uncertainties in the cost data, in particular for complex processes, the learning curve theory can be useful as a way to gather and structure cost data as a basis for estimating reductions in capital costs as a function of installed capacity. The theory can also be used to highlight critical steps in the different production processes, although currently there is a lack of detailed data from real world units. In the case of methanol and DME, the analysis shows that the gasification step (and in particular the gasifier with the syngas cleaning steps) are considered less mature compared to the other process steps of the production pathway and thus more effort with regard to R&D, design and resources are required to transform production processes from pilot and demonstration scales to commercial scale. This conclusion also has implications on what to expect in terms of overall reductions in investment costs of a large unit. The gasification part is only a small part of the project and, providing a sufficiently large scale of a unit, most components are commercially available and mature (little learning to be expected). Experiences from the GoBiGas project from which a detailed cost breakdown is available, indicate that it is rather the construction work (Service costs) where cost reductions can be expected.

Yet, this report has compared values from various energy conversion technologies from fossil and biomass-based resources and the collection of ranges for their LR values are used as basis for estimating numbers on learning for comparison and reference values. A general conclusion is that process steps and/or overall technologies which can be regarded as innovative are expected to have LR value close to 20% and the more mature technologies LR values of less than 10%.

The application of the learning curve framework gives a reduction of capital costs for the methanol and DME processes of around 11-18% by 2030 and 20-35% by 2050. The application of the learning curve framework gives a reduction of capital costs for the methanol and DME processes of around 11-18% by 2030 and 20-35% by 2050 for the reference case scenario. The conservative and optimistic scenarios for the future LR and CAGR values yield capital cost reduction of 5-8% by 2030 and 11-18% by 2050 for the conservative scenario and 18-29% by 2030 and 31-51% by 2050 for the optimistic scenario. These values can be compared with expert estimates based on real world experience which foresee cost reductions of not more than around 10% until year 2030 based on a large gasification project including the gas processing steps required to obtain a high-quality synthetic gas. Thus, this value is somewhere between the conservative and the reference scenario.

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# Appendix A

## Methanol production

| Source | Pacific Northwest National Laboratory | | | | | |
|---|---|---|---|---|---|---|
| | Techno-economic Analysis for the Thermochemical Conversion of Biomass to Liquid Fuels | | | | | |
| Year | 2011 | | | | | |
| | | | | | | |
| Technology: Biomass to Methanol through Indirect Gasification | | | | | | |
| | | | INPUT | | | |
| | **Name** | **Unit** | **Amount** | **Energy Unit** | **Energy content** | **Details** |
| **Feedstock** | | | | | | |
| | Dry wood chips | tonnes/day | 2,000 | MW | 437.1 | Dry basis |
| **Input Streams (in process)** | | | | | | |
| | Catalysts | kg/h methanol/L catalyst | 0.9 | MW methanol/L catalyst | 0.005 | ZnO/CuO |
| **Energy Utility Requirements** | | | | | | |
| | Natural gas | m3/hr | 0 | MW | 0 | |
| | Power consumption | | | MW | 30.7 | |
| **Water demand** | | | | | | |
| | Total water demand | m3/hr | 219.4 | | | Cooling tower makeup, Boiler feed water makeup |
| | | | OUTPUT | | | |
| **Product (s) and By-Products** | | | | | | |
| | Methanol | kg/hr | 35,461 | MW | 197 | |
| | Power Generation (Gross) | | | MW | 23.30 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Waste water** | | | | | | |
| | Wastewater | m3/hr | 83.5 | | | From methanol and gasification steps |
| | | | | | | |
| **Solid Wastes** | | | | | | |
| | Ash (Calcium Oxide) | kg/hr | 2590 | | | From gasification step |

| **Source** | **Pacific Northwest National Laboratory** | | | | | |
|---|---|---|---|---|---|---|
| | **Techno-economic Analysis for the Thermochemical Conversion of Biomass to Liquid Fuels** | | | | | |
| **Year:** | **2011** | | | | | |
| | | | | | | |
| **Technology: Biomass to Methanol through Direct Gasification** | | | | | | |
| **INPUT** | | | | | | |
| | **Name** | **Unit** | **Amount** | **Energy Unit** | **Energy content** | **Details** |
| **Feedstock** | | | | | | |
| | Dry wood chips | tonnes/day | 2,000 | MW | 437.1 | Dry basis |
| **Input Streams (in process)** | | | | | | |
| | Catalysts | kg/h methanol/L catalyst | 0.9 | | | ZnO/CuO |
| **Energy Utility Requirements** | | | | | | |
| | Natural gas | m3/hr | 2,922 | MW | 28.6 | |
| | Power consumption | | | MW | 23.8 | |
| **Water demand** | | | | | | |
| | Total water demand | m3/hr | 261 | | | Cooling tower makeup, Boiler feed water makeup |
| **OUTPUT** | | | | | | |
| **Product (s) and By-Products** | | | | | | |
| | Methanol | kg/hr | 37,525 | MW | 208.41 | |
| | Power Generation (Gross) | | | MW | 32.3 | |
| **Wastewater** | | | | | | |
| | Wastewater | m3/hr | 96.1 | | | From methanol and gasification steps |
| **Solid Wastes** | | | | | | |
| | Ash (Calcium Oxide) | kg/hr | 6,414 | | | From gasification step |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Technology:** | **Biomass to Methanol** | | | | | |
| **Source:** | **Ecoinvent V.2**<br>**Life Cycle Inventories of Bioen-ergy** | | | | | |
| | | | | | | |
| **Technology: Biomass to Methanol through fixed and fluidized bed gasification technology** | | | | | | |
| | | | **INPUT** | | | |
| | **Name** | **Unit** | **Amount** | **Energy Unit** | **Energy con-tent** | **Details** |
| | | | | | | |
| **Feedstock** | | | | | | |
| | wood chips, mixed,from forest man-agement | m3 | 0.0035 | | | |
| | wood chips, mixed, from the wood in-dustry | m3 | 0.0012 | | | |
| | waste wood chips, from waste demoli-tion and urban wood | m3 | 0.00076 | | | |
| **Input Streams (in process)** | | | | | | |
| | aluminium oxide | kg | 0.00024 | | | methanol synthesis step |
| | copper oxide | kg | 9.00E-05 | | | methanol synthesis step |
| | molybdenum | kg | 1.00E-05 | | | methanol synthesis step |
| | nickel | kg | 2.00E-05 | | | methanol synthesis step |
| | zinc, primary | kg | 3.00E-05 | | | methanol synthesis step |
| | dolomite | kg | 0.0051 | | | syngas production step fluidized bed |
| | zeolite, powder | kg | 0.00104 | | | syngas production step fluidized bed |
| | silica sand | kg | 0.0063 | | | syngas production step fluidized bed |
| | sodium hydroxide | kg | 0.00041 | | | syngas production step fluidized bed |
| | sulphuric acid, liquid, at plant | kg | 0.0016 | | | syngas production step fluidized bed |

| | | | | | | |
|---|---|---|---|---|---|---|
| | sodium hydroxide | kg | 0.00042 | | | in syngas fix bed |
| | sulphuric acid, liquid, at plant | kg | 0.00167 | | | in syngas fix bed |
| | | | | | | |
| **Energy Utility Requirements** | | | | | | |
| | electricity, medium voltage | kWh | 0.28 | | | methanol synthesis step |
| | electricity, medium voltage | kWh | 0.013 | | | in syngas fluidized bed |
| | electricity, medium voltage | kWh | 0.014 | | | in syngas fix bed |
| | | | | | | |
| **Water demand** | | | | | | |
| | water, deionised | kg | 0.85 | | | methanol synthesis step |
| | tap water, at user | kg | 0.072 | | | syngas production step fluidized bed |
| | tap water, at user | kg | 0.074 | | | |
| | | | | | | |
| **OUTPUT** | | | | | | |
| **Product (s) and By-Products** | | | | | | |
| | Methanol | kg | 1 | | | |
| **Waste water** | | | | | | |
| | Wastewater | m3 | 0.0053 | | | methanol synthesis step |
| | Wastewater | m3 | 0.000051 | | | in syngas fix bed |
| **Solid Wastes** | | | | | | |
| | wood ash mixture, pure, 0% water, to municipal incineration | kg | 0.00112 | | | syngas production step fluidized bed |
| | wood ash mixture, pure, 0% water, to sanitary landfill | kg | 0.00085 | | | syngas production step fluidized bed |
| | inert waste, 5% water, to inert material landfill | kg | 0.0114 | | | syngas production step fluidized bed |
| | zeolite, 5% water, to inert material landfill | kg | 0.00104 | | | syngas production step fluidized bed |
| | wood ash mixture, pure, 0% water, to municipal incineration | | 0.0012 | | | in syngas fix bed |
| | wood ash mixture, pure, 0% water, to sanitary landfill | | 0.00087 | | | in syngas fix bed |

| Source | VTT | | | | | |
|---|---|---|---|---|---|---|
| | **Liquid transportation fuels via large-scale fluidised- bed gasification of lignocellulosic biomass** | | | | | |
| **Year** | **2013** | | | | | |
| **Technology: Biomass to Methanol through fluidized bed gasifier** | | | | | | |
| **INPUT** | | | | | | |
| | **Name** | **Unit** | **Amount** | **Energy Unit** | **Energy content** | **Details** |
| **Feedstock** | | | | | | |
| | Dry wood chips | tonnes/day | 73,800 | MW | 335 | |
| **Input Streams (in process)** | | | | | | |
| | Oxygen | kg/hr | 19,800 | | | In gasifier |
| | Oxygen | kg/hr | 15,480 | | | In reformer |
| **Energy Utility Requirements** | | | | | | |
| | Power consumption | | | MW | 29.9 | |
| | Steam from auxiliary boiler | kg/hr | 19,080 | | | |
| **Water demand** | | | | | | |
| | - | | | | | |
| **OUTPUT** | | | | | | |
| **Product (s) and By-Products** | | | | | | |
| | Methanol | kg/hr | 33,120 | MW | 184 | |
| | Power Generation (Gross) | MW | | MW | 32.5 | |
| | District heat (90 °C) | MW | | MW | 0 | |
| **Waste water** | | | | | | |
| | - | | | | | |
| **Solid Wastes** | | | | | | |
| | - | | | | | |

## DME production

| Source | Pacific Northwest National Laboratory | | | | | |
|---|---|---|---|---|---|---|
| | Techno-economic Analysis for the Thermochemical Conversion of Biomass to Liquid Fuels | | | | | |
| Year | 2011 | | | | | |
| Technology Biomass to DME through Indirect Gasification | | | | | | |
| INPUT | | | | | | |
| | Name | Unit | Amount | Energy Unit | Energy content | Details |
| Feedstock | | | | | | |
| | Dry wood chips | tonnes/day | 2,000 | MW | 437.1 | Dry basis |
| Input Streams (in process) | | | | | | |
| | Catalysts | kg/h methanol/L catalyst | 0.9 | MW methanol/L catalyst | | ZnO/CuO |
| Energy Utility Requirements | | | | | | |
| | Natural gas | m3/hr | 0 | MW | 0 | |
| | Power consumption | | | MW | 28.84 | |
| Water demand | | | | | | |
| | Total water demand | m3/hr | 243 | | | Cooling tower makeup, Boiler feed water makeup |
| OUTPUT | | | | | | |
| Product (s) and By-Products | | | | | | |
| | DME | kg/hr | 28,130 | MW | 206.7 | |
| | Power Generation (Gross) | | | MW | 29 | |
| Wastewater | | | | | | |
| | Wastewater | m3/hr | 97 | | | From methanol and gasification steps |
| Solid Wastes | | | | | | |
| | Ash (Calcium Oxide) | kg/hr | 2,590 | | | From gasification step |

| Source | Pacific Northwest National Laboratory | | | | | |
|---|---|---|---|---|---|---|
| | **Techno-economic Analysis for the Thermochemical Conversion of Biomass to Liquid Fuels** | | | | | |
| **Year** | **2011** | | | | | |
| **Technology: Biomass to DME through Direct Gasification** | | | | | | |
| | | | **INPUT** | | | |
| | **Name** | **Unit** | **Amount** | **Energy Unit** | **Energy content** | **Details** |
| **Feedstock** | | | | | | |
| | Dry wood chips | tonnes/day | 2,000 | MW | 437 | Dry basis |
| **Input Streams (in process)** | | | | | | |
| | Catalysts | kg/h methanol/L catalyst | 0.9 | MW methanol/L catalyst | 17.4 | ZnO/CuO |
| **Energy Utility Requirements** | | | | | | |
| | Natural gas | m3/hr | 0 | MW | 0 | |
| | Power consumption | | | MW | 19.9 | |
| **Water demand** | | | | | | |
| | Total water demand | m3/hr | 280.4 | | | Cooling tower makeup, Boiler feed water makeup |
| | | | **OUTPUT** | | | |
| **Product (s) and By-Products** | | | | | | |
| | DME | kg/hr | 26,394 | MW | 194 | |
| | Power Generation (Gross) | | | MW | 29 | |
| **Waste water** | | | | | | |
| | Wastewater | m3/hr | 109.25 | | | From methanol and gasification steps |
| | | | | | | |
| **Solid Wastes** | | | | | | |
| | Ash (Calcium Oxide) | kg/hr | 2,590 | | | From gasification step |

| **Source** | **VTT** | | | | | |
|---|---|---|---|---|---|---|
| | **Liquid transportation fuels via large-scale fluidised- bed gasification of lignocellulosic bio-mass** | | | | | |
| **Year** | **2013** | | | | | |
| | | | | | | |
| **Technology: Biomass to DME through fluid-ized bed gasifier** | | | | | | |
| **INPUT** | | | | | | |
| | **Name** | **Unit** | **Amount** | **Energy Unit** | **Energy content** | **Details** |
| **Feedstock** | | | | | | |
| | Dry wood chips | tonnes/day | 73,800 | MW | 335 | |
| **Input Streams (in process)** | | | | | | |
| | Oxygen | kg/hr | 19,800 | | | In gasifier |
| | Oxygen | kg/hr | 15,480 | | | In refor-mer |
| **Energy Utility Requirements** | | | | | | |
| | Power consumption | | | MW | 29 | |
| | Steam from auxiliary boiler | kg/hr | 30,600 | | | |
| **Water demand** | | | | | | |
| | = | | | | | |
| **OUTPUT** | | | | | | |
| **Product (s) and By-Products** | | | | | | |
| | DME | kg/hr | 24,840 | MW | 179 | |
| | Power Generation (Gross) | MW | | MW | 36.4 | |
| | District heat (90 °C) | MW | | MW | 0 | |
| **Waste water** | | | | | | |
| | = | | | | | |
| **Solid Wastes** | | | | | | |
| | = | | | | | |

# Appendix B

Table B1 provides an overview of studies conducted on technological learning in bioelectricity systems. For CHP and biogas, Junginger et al. (2005); Junginger, de Visser et al. (2006) conducted research on experience curves in CHP and biogas plants in Sweden and Finland and Denmark respectively. Furthermore, the IEA presents a progress ratio of 85% for biomass electricity plants for the EU-ATLAS project. It is however unclear if this is based on empirical evidence and if so, what data source was used.

*Table B 1 Overview of experience curves for biomass electricity in Green-X and published in literature (Faaij and Junginger 2010).*

| Reference | PR | Time frame | Price data region | Capacity |
|---|---|---|---|---|
| **Green-X** | | | | |
| **Biomass/biogas small scale (electricity and CHP)** | 92.5% | <2010 | Global | Global |
| | 90% | >2010 | Global | Global |
| **Biomass/biogas large scale (electricity and CHP)** | 97.5% | <2010 | Global | Global |
| | 95% | >2010 | Global | Global |
| **Waste (electricity and CHP)** | 97.5% | <2010 | Global | Global |
| | 95% | >2010 | Global | Global |
| **Biomass cofiring** | 0% | | | |
| **Junginger et al. 2005** | | | | |
| **Logistic chain forest wood chips CHP (E/kWe)** | 85-88% | 1975-2003 | Sweden/Finland | Sweden/Finland |
| | 75-91% | 1983-2002 | Sweden | Sweden |
| **Junginger et al. 2006** | | | | |
| **Biogas (m3 biogas/day)** | 88% | 1984-1998 | | |
| **Biogas electricity** | 85-100% | 1984-2001 | Denmark | Denmark |
| **Electricity from biomass CHP** | 91-92% | 1990-2002 | Sweden | Sweden |
| **IEA, 2000** | | | | |
| **Electricity from biomass** | 85% | | EU | EU |

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N.º 764799.

# Appendix C

*Table C 1 CAPEX decomposition for methanol*

| | Indirect gasfication (Zhu, et al., 2011) | Direct gasfication (Zhu, et al., 2011) | | VTT (Hannula, et al., 2013) |
|---|---|---|---|---|
| **Auxiliary equipment** | | | | |
| **Air separation unit** | 0.0 | 30.4 | **Buildings** | 22.2 |
| **Feed prep and drying** | 33.0 | 36.3 | **Oxygen production** | 56.1 |
| Remainder off-site battery limits | 6.5 | 6.5 | **Feedstock pretreat-ment** | 37.9 |
| **Gasification island** | | | | |
| **Gasification with tar reforming, heat recovery, scrubbing** | 44.9 | 116.3 | **Gasification** | 60.3 |
| **Syngas cleanup & compression** | 84.7 | 93.5 | **Hot-gas cleaning** | 45.8 |
| | | | **CO shift** | 7.3 |
| | | | **Syngas cooling** | 12.0 |
| | | | **Compression** | 9.4 |
| | | | **Acid gas removal** | 42.0 |
| **Power island** | | | | |
| **Steam system and power genera-tion** | 27.7 | 33.6 | **Steam system and power generation** | 27.8 |
| **Methanol synthesis** | | | | |
| **Methanol synthesis & purification** | 37.2 | 39.5 | **Syngas compressor** | 5.7 |
| | | | **MeOH synth+dist.+ rc cmp** | 63.0 |
| **Total CAPEX (MEuro, 2018)** | **234.0** | **356.2** | | **389.4** |

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N.º 764799.

*Table C 2 CAPEX decomposition for methanol*

| | Indirect gasfication (Zhu, et al., 2011) | Direct gasfication (Zhu, et al., 2011) | | VTT (Hannula, et al., 2013) |
|---|---|---|---|---|
| **Auxiliary equipment** | | | | |
| **Air separation unit** | 0.0 | 30.4 | **Buildings** | 22.2 |
| **Feed prep and drying** | 33.0 | 36.3 | **Oxygen production** | 56.1 |
| Remainder off-site battery limits | 6.5 | 6.8 | **Feedstock pretreatment** | 37.9 |
| **Gasification island** | | | | |
| **Gasification with tar reforming, heat recovery, scrubbing** | 40.4 | 122.2 | **Gasification** | 60.3 |
| **Syngas cleanup & compression** | 84.7 | 93.5 | **Hot-gas cleaning** | 45.8 |
| | | | **CO shift** | 7.3 |
| | | | **Syngas cooling** | 12.0 |
| | | | **Compression** | 9.4 |
| | | | **Acid gas removal** | 42.3 |
| **Power island** | | | | |
| Steam system and power generation | 28.6 | 34.5 | **Steam system and power generation** | 28.1 |
| **Methanol synthesis** | | | **DME synthesis** | |
| **Methanol synthesis & purification** | 24.5 | 22.7 | **Syngas compressor** | 6.3 |
| | | | **MeOH synth+dist.+ rc cmp** | 73.0 |
| **DME synthesis** | | | | |
| | 8.3 | 7.7 | | |
| **Total CAPEX (MEuro, 2018)** | **226.0** | **354.1** | **0** | **400.6** |

# Results of Sensitivity analysis

*Table C 3 CAPEX reduction projections and sensitivity analysis for methanol through indirect gasification (the cost data were obtained from Zhu et al., 2011).*

| Base case scenario | 2018 | 2020 | 2030 | 2050 | Conservative Scenario | | 2020 | 2030 | 2050 | Optimistic Scenario | 2018 | 2020 | 2030 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auxiliary equipment** | | | | | **Auxiliary equipment** | **2018** | | | | **Auxiliary equipment** | | | | |
| Air separation unit | 0.0 | 0.0 | 0.0 | 0.0 | Air separation unit | 0.0 | 0.0 | 0.0 | 0.0 | Air separation unit | 0.0 | 0.0 | 0.0 | 0.0 |
| Feed prep and drying | 33.0 | 32.5 | 31.4 | 29.2 | Feed prep and drying | 33.0 | 32.8 | 32.4 | 31.4 | Feed prep and drying | 33.0 | 32.0 | 30.0 | 26.3 |
| Remainder off-site battery limits | 6.5 | 6.4 | 6.2 | 5.7 | Remainder off-site battery limits | 6.5 | 6.4 | 6.4 | 6.2 | Remainder off-site battery limits | 6.5 | 6.3 | 5.9 | 5.2 |
| **Gasification island** | | | | | **Gasification island** | | | | | **Gasification island** | | | | |
| Gasification with tar reforming, heat recovery, scrubbing | 44.9 | 40.6 | 33.3 | 22.5 | Gasification with tar reforming, heat recovery, scrubbing | 44.9 | 43.0 | 39.4 | 33.1 | Gasification with tar reforming, heat recovery, scrubbing | 44.9 | 37.5 | 26.3 | 12.9 |
| Syngas cleanup & compression | 84.7 | 76.7 | 63.0 | 42.4 | Syngas cleanup & compression | 84.7 | 81.1 | 74.4 | 62.5 | Syngas cleanup & compression | 84.7 | 70.9 | 49.7 | 24.4 |
| **Power island** | | | | | **Power island** | | | | | **Power island** | | | | |
| Steam system and power generation | 27.7 | 27.3 | 26.3 | 24.5 | Steam system and power generation | 27.7 | 27.5 | 27.2 | 26.4 | Steam system and power generation | 27.7 | 26.9 | 25.2 | 22.1 |
| **Methanol synthesis** | | | | | **Methanol synthesis** | | | | | **Methanol synthesis** | | | | |
| Methanol synthesis & purification | 37.2 | 36.5 | 35.3 | 32.9 | Methanol synthesis & purification | 37.2 | 36.9 | 36.4 | 35.4 | Methanol synthesis & purification | 37.2 | 36.0 | 33.7 | 29.6 |
| **Total CAPEX** | **234.0** | **220.0** | **195.4** | **157.2** | **Total CAPEX** | **234.0** | **227.8** | **216.0** | **195.1** | **Total CAPEX** | **234.0** | **209.6** | **170.8** | **120.5** |
| **% Cost reduction** | | **6%** | **16%** | **33%** | **% Cost reduction** | | **3%** | **8%** | **17%** | | | **10%** | **27%** | **48%** |

*Table C 4 CAPEX reduction projections and sensitivity analysis for methanol through direct gasification (the cost data were obtained from Zhu et al., 2011).*

| **Base case scenario** | **2018** | **2020** | **2030** | **2050** | **Conservative Scenario** | | **2020** | **2030** | **2050** | **Optimistic Scenario** | **2018** | **2020** | **2030** | **2050** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auxiliary equipment** | | | | | **Auxiliary equipment** | **2018** | | | | **Auxiliary equipment** | | | | |
| Air separation unit | 30.4 | 29.9 | 28.8 | 26.9 | Air separation unit | 30.4 | 30.2 | 29.8 | 28.9 | Air separation unit | 30.4 | 29.4 | 27.6 | 24.2 |
| Feed prep and drying | 36.3 | 35.7 | 34.4 | 32.1 | Feed prep and drying | 36.3 | 36.0 | 35.5 | 34.5 | Feed prep and drying | 36.3 | 35.1 | 32.9 | 28.9 |
| Remainder off-site battery limits | 6.5 | 6.4 | 6.2 | 5.7 | Remainder off-site battery limits | 6.5 | 6.4 | 6.4 | 6.2 | Remainder off-site battery limits | 6.5 | 6.3 | 5.9 | 5.2 |
| **Gasification island** | | | | | **Gasification island** | | | | | **Gasification island** | | | | |
| Gasification with tar reforming, heat recovery, scrubbing | 116.3 | 105.3 | 86.4 | 58.2 | Gasification with tar reforming, heat recovery, scrubbing | 116.3 | 111.3 | 102.1 | 85.9 | Gasification with tar reforming, heat recovery, scrubbing | 116.3 | 97.3 | 68.2 | 33.5 |
| Syngas cleanup & compression | 93.5 | 84.7 | 69.5 | 46.8 | Syngas cleanup & compression | 93.5 | 89.6 | 82.1 | 69.1 | Syngas cleanup & compression | 93.5 | 78.3 | 54.9 | 26.9 |
| **Power island** | | | | | **Power island** | | | | | **Power island** | | | | |
| Steam system and power generation | 33.6 | 33.1 | 31.9 | 29.7 | Steam system and power generation | 33.6 | 33.4 | 32.9 | 32.0 | Steam system and power generation | 33.6 | 32.6 | 30.5 | 26.8 |
| **Methanol synthesis** | | | | | **Methanol synthesis** | | | | | **Methanol synthesis** | | | | |
| Methanol synthesis & purification | 39.5 | 38.9 | 37.5 | 35.0 | Methanol synthesis & purification | 39.5 | 39.3 | 38.7 | 37.6 | Methanol synthesis & purification | 39.5 | 38.3 | 35.9 | 31.5 |
| | | | | | | | | | | | | | | |
| **Total CAPEX** | **356.2** | **333.9** | **294.8** | **234.5** | **Total CAPEX** | **356.2** | **346.2** | **327.5** | **294.2** | **Total CAPEX** | **356.2** | **317.3** | **255.8** | **177.0** |
| **% Cost reduction** | | **6%** | **17%** | **34%** | | | **3%** | **8%** | **17%** | | | **11%** | **28%** | **50%** |

*Table C 5 CAPEX reduction projections and sensitivity analysis for methanol (the cost data were obtained from Hannula, et al., 2013).*

| Base case scenario | 2018 | 2020 | 2030 | 2050 | Conservative Scenario | 2018 | 2020 | 2030 | 2050 | Optimistic Scenario | 2018 | 2020 | 2030 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auxiliary equipment** | | | | | **Auxiliary equipment** | | | | | **Auxiliary equipment** | | | | |
| Buildings | 22.2 | 21.8 | 21.0 | 19.6 | Buildings | 22.2 | 22.0 | 21.7 | 21.1 | Buildings | 22.2 | 21.5 | 20.1 | 17.7 |
| Oxygen production | 56.1 | 55.2 | 53.3 | 49.6 | Oxygen production | 56.1 | 55.7 | 55.0 | 53.4 | Oxygen production | 56.1 | 54.3 | 50.9 | 44.7 |
| Feedstock pretreatment | 37.9 | 37.2 | 35.9 | 33.5 | Feedstock pretreatment | 37.9 | 37.6 | 37.1 | 36.0 | Feedstock pretreatment | 37.9 | 36.7 | 34.3 | 30.2 |
| **Gasification island** | | | | | **Gasification island** | | | | | **Gasification island** | | | | |
| Gasification | 60.3 | 54.6 | 44.8 | 30.2 | Gasification | 60.3 | 57.7 | 52.9 | 44.5 | Gasification | 60.3 | 50.4 | 35.3 | 17.4 |
| Hot-gas cleaning | 45.8 | 41.5 | 34.0 | 22.9 | Hot-gas cleaning | 45.8 | 43.8 | 40.2 | 33.8 | Hot-gas cleaning | 45.8 | 38.3 | 26.8 | 13.2 |
| CO shift | 7.3 | 6.6 | 5.4 | 3.7 | CO shift | 7.3 | 7.0 | 6.4 | 5.4 | CO shift | 7.3 | 6.7 | 5.6 | 3.9 |
| Syngas cooling | 12.0 | 11.8 | 11.4 | 10.6 | Syngas cooling | 12.0 | 11.9 | 11.8 | 11.4 | Syngas cooling | 12.0 | 11.6 | 10.9 | 9.6 |
| Compression | 9.4 | 9.3 | 9.0 | 8.3 | Compression | 9.4 | 9.4 | 9.2 | 9.0 | Compression | 9.4 | 9.1 | 8.6 | 7.5 |
| Acid gas removal | 42.0 | 41.3 | 39.8 | 37.1 | Acid gas removal | 42.0 | 41.7 | 41.1 | 40.0 | Acid gas removal | 42.0 | 41.3 | 39.9 | 37.2 |
| **Power island** | | | | | **Power island** | | | | | **Power island** | | | | |
| Steam system and power generation | 27.8 | 27.3 | 26.4 | 24.6 | Steam system and power generation | 27.8 | 27.6 | 27.2 | 26.5 | Steam system and power generation | 27.8 | 26.9 | 25.3 | 22.2 |
| **Methanol synthesis** | | | | | **Methanol synthesis** | | | | | **Methanol synthesis** | | | | |
| Syngas compressor | 5.7 | 5.6 | 5.4 | 5.0 | Syngas compressor | 5.7 | 5.6 | 5.5 | 5.4 | Syngas compressor | 5.7 | 5.5 | 5.1 | 4.5 |
| MeOH synth+dist.+ rc cmp | 63.0 | 61.9 | 59.7 | 55.7 | MeOH synth+dist.+ rc cm | 63.0 | 62.5 | 61.7 | 59.9 | MeOH synth+dist.+ rc cmp | 63.0 | 61.0 | 57.1 | 50.2 |
| **Total CAPEX** | **389.4** | **374.0** | **346.2** | **300.9** | **Total CAPEX** | **389.4** | **382.7** | **369.8** | **346.4** | **Total CAPEX** | **389.4** | **363.3** | **320.0** | **258.2** |
| **% Cost redaction** | | **4%** | **11%** | **23%** | **% Cost redaction** | | **2%** | **5%** | **11%** | **% Cost redaction** | | **7%** | **18%** | **34%** |

*Table C 6 CAPEX reduction projections and sensitivity analysis for DME through indirect gasification (the cost data were obtained from Zhu, et al., 2011).*

| **Base case scenario** | | **2020** | **2030** | **2050** | **Conservative Scenario** | **2018** | **2020** | **2030** | **2050** | **Optimistic Scenario** | **2018** | **2020** | **2030** | **2050** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auxiliary equipment** | **2018** | | | | **Auxiliary equipment** | | | | | **Auxiliary equipment** | | | | |
| Air separation unit | 0.0 | 0.0 | 0.0 | 0.0 | Air separation unit | 0.0 | 0.0 | 0.0 | 0.0 | Air separation unit | 0.0 | 0.0 | 0.0 | 0.0 |
| Feed prep and drying | 33.0 | 32.5 | 31.4 | 29.2 | Feed prep and drying | 33.0 | 32.8 | 32.4 | 31.4 | Feed prep and drying | 33.0 | 32.0 | 30.0 | 26.3 |
| Remainder off-site battery limits | 6.5 | 6.4 | 6.2 | 5.7 | Remainder off-site battery limits | 6.5 | 6.4 | 6.4 | 6.2 | Remainder off-site battery limits | 6.5 | 6.3 | 5.9 | 5.2 |
| **Gasification island** | | | | | **Gasification island** | | | | | **Gasification island** | | | | |
| Gasification with tar reforming, heat recovery, scrubbing | 40.4 | 36.6 | 30.1 | 20.2 | Gasification with tar reforming, heat recovery, scrubbing | 40.4 | 38.7 | 35.5 | 29.9 | Gasification with tar reforming, heat recovery, scrubbing | 40.4 | 33.8 | 23.7 | 11.6 |
| Syngas cleanup & compression | 84.7 | 76.7 | 63.0 | 42.4 | Syngas cleanup & compression | 84.7 | 81.1 | 74.4 | 62.5 | Syngas cleanup & compression | 84.7 | 70.9 | 49.7 | 24.4 |
| **Power island** | | | | | **Power island** | | | | | **Power island** | | | | |
| Steam system and power generation | 28.6 | 28.1 | 27.2 | 25.3 | Steam system and power generation | 28.6 | 28.4 | 28.0 | 27.2 | Steam system and power generation | 28.6 | 27.7 | 26.0 | 22.8 |
| **Methanol synthesis** | | | | | Methanol synthesis | | | | | Methanol synthesis | | | | |
| Methanol synthesis & purification | 24.5 | 24.1 | 23.2 | 21.7 | Methanol synthesis & purification | 24.5 | 24.3 | 24.0 | 23.3 | Methanol synthesis & purification | 24.5 | 23.7 | 22.2 | 19.5 |
| **DME synthesis** | | | | | **DME synthesis** | | | | | **DME synthesis** | | | | |
| DME synthesis & purification | 8.3 | 8.1 | 7.8 | 7.1 | DME synthesis & purification | 8.3 | 8.2 | 8.0 | 7.8 | DME synthesis & purification | 8.3 | 8.0 | 7.4 | 6.3 |
| **Total CAPEX** | **226.0** | **212.5** | **188.7** | **151.7** | **Total CAPEX** | **226.0** | **220.0** | **208.6** | **188.3** | **Total CAPEX** | **226.0** | **202.4** | **164.8** | **116.2** |
| **%Cost Reduction** | | **6%** | **17%** | **33%** | **%Cost Reduction** | | **3%** | **8%** | **17%** | **%Cost Reduction** | | **10%** | **27%** | **49%** |

*Table C 7 CAPEX reduction projections and sensitivity analysis for DME through direct gasification, (the cost data were obtained from (Zhu, et al., 2011))*

| **Base case scenario** | **2018** | **2020** | **2030** | **2050** | **Conservative Scenario** | **2018** | **2020** | **2030** | **2050** | **Optimistic Scenario** | **2018** | **2020** | **2030** | **2050** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auxiliary equipment** | | | | | **Auxiliary equipment** | | **2020** | **2030** | **2050** | **Auxiliary equipment** | | | | |
| Air separation unit | 30.4 | 29.9 | 28.8 | 26.9 | Air separation unit | 30.4 | 30.2 | 29.8 | 28.9 | Air separation unit | 30.4 | 29.4 | 27.6 | 24.2 |
| **Feed prep and drying** | 36.3 | 35.7 | 34.4 | 32.1 | Feed prep and drying | 36.3 | 36.0 | 35.5 | 34.5 | Feed prep and drying | 36.3 | 35.1 | 32.9 | 28.9 |
| Remainder off-site battery limits | 6.8 | 6.7 | 6.4 | 6.0 | Remainder off-site battery limits | 6.8 | 6.7 | 6.6 | 6.5 | Remainder off-site battery limits | 6.8 | 6.6 | 6.2 | 5.4 |
| **Gasification island** | | | | | **Gasification island** | | | | | **Gasification island** | | | | |
| Gasification with tar reforming, heat recovery, scrubbing | 122.2 | 110.7 | 90.8 | 61.1 | Gasification with tar reforming, heat recovery, scrubbing | 122.2 | 117.0 | 107.3 | 90.2 | Gasification with tar reforming, heat recovery, scrubbing | 122.2 | 102.3 | 71.6 | 35.2 |
| Syngas cleanup & compression | 93.5 | 84.7 | 69.5 | 46.8 | Syngas cleanup & compression | 93.5 | 89.6 | 82.1 | 69.1 | Syngas cleanup & compression | 93.5 | 78.3 | 54.9 | 26.9 |
| **Power island** | | | | | **Power island** | | | | | **Power island** | | | | |
| Steam system and power generation | 34.5 | 33.9 | 32.8 | 30.5 | Steam system and power generation | 34.5 | 34.3 | 33.8 | 32.9 | Steam system and power generation | 34.5 | 33.4 | 31.3 | 27.5 |
| **Methanol synthesis** | | | | | Methanol synthesis | | | | | Methanol synthesis | | | | |
| Methanol synthesis & purification | 22.7 | 22.3 | 21.6 | 20.1 | Methanol synthesis & purification | 22.7 | 22.6 | 22.2 | 21.6 | Methanol synthesis & purification | 22.7 | 22.0 | 20.6 | 18.1 |
| **DME synthesis** | | | | | **DME synthesis** | | | | | **DME synthesis** | | | | |
| | 7.7 | 7.5 | 7.2 | 6.6 | | 7.7 | 7.6 | 7.5 | 7.2 | | 7.7 | 7.4 | 6.8 | 5.9 |
| **Total CAPEX** | **354.1** | **331.4** | **291.6** | **230.2** | **Total CAPEX** | **354.1** | **344.0** | **324.9** | **290.9** | **Total CAPEX** | **354.1** | **314.5** | **252.0** | **172.2** |
| **% Cost reduction** | | **6%** | **18%** | **35%** | **% Cost reduction** | | **3%** | **8%** | **18%** | | **% Cost reduction** | **11%** | **29%** | **51%** |

*Table C 8 CAPEX reduction projections and sensitivity analysis for DME (the cost data were obtained from Hannula, et al., 2013).*

| **Base case scenario** | | **2020** | **2030** | **2050** | **Conservative Scenario** | | **2020** | **2030** | **2050** | **Optimistist Scenario** | | **2020** | **2030** | **2050** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auxiliary equipment** | 2018 | | | | Auxiliary equipment | 2018 | | | | Auxiliary equipment | 2018 | | | |
| Buildings | 22.2 | 21.8 | 21.0 | 19.6 | Buildings | 22.2 | 22.0 | 21.7 | 21.1 | Buildings | 22.2 | 21.5 | 20.1 | 17.7 |
| Oxygen production | 56.1 | 55.2 | 53.3 | 49.6 | Oxygen production | 56.1 | 55.7 | 55.0 | 53.4 | Oxygen production | 56.1 | 54.3 | 50.9 | 44.7 |
| Feedstock pretreatment | 37.9 | 37.2 | 35.9 | 33.5 | Feedstock pretreatment | 37.9 | 37.6 | 37.1 | 36.0 | Feedstock pretreatment | 37.9 | 36.7 | 34.3 | 30.2 |
| **Gasification island** | | | | | **Gasification island** | | | | | **Gasification island** | | | | |
| **Gasification** | 60.3 | 54.6 | 44.8 | 30.2 | Gasification | 60.3 | 57.7 | 52.9 | 44.5 | Gasification | 60.3 | 50.4 | 35.3 | 17.4 |
| Hot-gas cleaning | 45.8 | 41.5 | 34.0 | 22.9 | Hot-gas cleaning | 45.8 | 43.8 | 40.2 | 33.8 | Hot-gas cleaning | 45.8 | 38.3 | 26.8 | 13.2 |
| CO shift | 7.3 | 6.6 | 5.4 | 3.7 | CO shift | 7.3 | 7.0 | 6.4 | 5.4 | **CO shift** | **7.3** | 6.7 | 5.6 | 3.9 |
| Syngas cooling | 12.0 | 11.8 | 11.4 | 10.6 | Syngas cooling | 12.0 | 11.9 | 11.8 | 11.4 | Syngas cooling | 12.0 | 11.6 | 10.9 | 9.6 |
| Compression | 9.4 | 9.3 | 9.0 | 8.3 | Compression | 9.4 | 9.4 | 9.2 | 9.0 | Compression | 9.4 | 9.1 | 8.6 | 7.5 |
| Acid gas removal | 42.3 | 41.6 | 40.2 | 37.4 | Acid gas removal | 42.3 | 42.0 | 41.4 | 40.3 | Acid gas removal | 42.3 | 41.0 | 38.4 | 33.7 |
| **Power island** | | | | | **Power island** | | | | | **Power island** | | | | |
| Steam system and power generation | 28.1 | 27.6 | 26.6 | 24.8 | Steam system and power generation | 28.1 | 27.9 | 27.5 | 26.7 | Steam system and power generation | 28.1 | 27.2 | 25.5 | 22.4 |
| **DME synthesis** | | | | | **DME synthesis** | | | | | **DME synthesis** | | | | |
| Syngas compressor | 6.3 | 6.1 | 5.9 | 5.5 | Syngas compressor | 6.3 | 6.2 | 6.1 | 5.9 | Syngas compressor | 6.3 | 6.1 | 5.7 | 5.0 |
| DME synth + dist. | 73.0 | 71.5 | 68.5 | 63.0 | DME synth + dist. | 73.0 | 72.4 | 71.1 | 68.6 | DME synth + dist. | 73.0 | 70.3 | 65.1 | 55.9 |
| **Total CAPEX** | **400.6** | **384.7** | **356.1** | **309.3** | **Total CAPEX** | **400.6** | **393.7** | **380.4** | **356.3** | **Total CAPEX** | **400.6** | **373.2** | **327.3** | **261.1** |
| **% Cost reduction** | | **4%** | **11%** | **23%** | **% Cost reduction** | | **2%** | **5%** | **11%** | **% Cost reduction** | | **7%** | **18%** | **35%** |