

PROSPECTS
FOR
HYDROGEN
FROM
BIOMASS



IEA
Hydrogen
Implementing
Agreement

Annex 16
Subtask B
Final Report
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Foreword

Hydrogen is an energy carrier with the potential to open the door to a wide range of new energy technologies and policy options. Fuel cells powered by hydrogen, or by other fuels, can achieve high efficiencies and have a variety of possible uses in mobile and stationary applications. In the right circumstances hydrogen and fuel cells technologies could make major contributions to the key policy objectives of energy security and mitigation of carbon dioxide (CO₂) emissions, especially in the transportation sector. Recent advances in hydrogen and fuel cell research and development have increased the interest of the international community in these technologies which have the potential to create paradigm shifts across all sectors using energy. Within this context of active international development, among the multitude of routes available to supply hydrogen in a future more sustainable energy system, biomass holds a particularly important place, being a renewable source.

Acknowledgments

This report is the final synthesis of results from the Subtask B group under the IEA Hydrogen Implementing Agreement, Task 16, *Hydrogen from Carbon-containing materials*. The main authors of the report are Jan Erik Hanssen and Elisabet Fjermestad Hagen with active contribution from Subtask B members*.

Two previous reports prepared for Subtask B are incorporated as primary background material:

- *Hydrogen from Biomass: State of the Art and Research Challenges* by the National Renewable Energy Laboratory (United States) (authors: Tom Milne, Carolyn Elam and Bob Evans);
- *Renewable Hydrogen in a Future Hydrogen Economy* by Biomass Technology Group (Netherlands) and Hydro (Norway) (project coordinator: L. (Bert) van de Beld, BTG).

These were prepared with the kind support of IEA HIA (ref. IEA/H2/TR-02/001) and the European Commission (FP5 Contract no. ENK5-CT-2002-80633). In addition, Dr. Suresh Babu, Leader of Task 33 in the IEA *Bioenergy* programme, kindly prepared for our use a dedicated in-depth review:

- *Biomass gasification for hydrogen production: process description and research needs*

We acknowledge with great thanks these essential contributions. However, all conclusions and recommendations in the present report are solely the opinions of Subtask B group members.

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SUMMARY and CONCLUSIONS

In determining how to present the conclusions in this Final report, Subtask B group members decided to specifically target well-oriented technology professionals in the energy industry with principal interests in sustainable and market-capable supply routes for hydrogen, rather than R&D or technology specialists either in biomass processing or specific hydrogen technologies. There is an abundance of previous studies of the subject, most of which have had a technical or R&D perspective. Our chosen way, building on this existing knowledge base, has been to treat biomass to hydrogen in a basically pragmatic manner, trying to adopt an industry view based in markets – current and future – and practicable industrial processes. In this spirit, we assessed the general conditions and magnitude for the various supply options, within a general picture of how a future energy system with hydrogen playing a central role can be envisaged, *before* moving on to assess the technologies, using a simplified value chain approach. Based on the outcome of the technology assessment, we proceeded to outline possible applications. Finally, the report was laid out with the intent of forming a useful supplement to the recent IEA *Energy technology analysis* volume on hydrogen ¹. Our hope is that the Subtask B report will be seen as both broadening and deepening the scope of this important milestone, specifically on the issue of how biomass may be established as an important source of “green hydrogen”, both globally and locally, its advantages complementing those of other high volume pathways.

Below are summarised our main findings conclusions formulated in ten points, followed by our summary conclusions in terms of the major gaps, R&D needs and recommendations.

1. Biomass is the only direct * path to hydrogen from a renewable energy source (RES) that can be implemented in the near term and without a need for major scientific breakthroughs. As such, biomass-to-hydrogen is a complementary route to increasing the overall share of renewables into the world energy mix.
2. In a fully developed hydrogen-based energy system, expected not before 2050, with hydrogen established as a main energy carrier of importance equal to electricity, biomass could in a sustainable way contribute as much as 20% of the hydrogen needed.
3. Moreover, in a transition phase, biomass could contribute – at reasonable cost – most of the renewable based hydrogen needed up to a point where hydrogen has a position where it carries 10% of the energy carried as electricity, using projections for 2030.
4. Thermochemical routes for biomass gasification, and processing of the resultant synthesis gas to H₂, are clear candidates for commercialisation within 10 to 15 years. By continuing to adapt technologies of gasification commercialised for coal, the remaining work appears manageable – given a concerted and *industrially focused* development effort. The current strong interest for Fischer-Tropsch fuels may constitute an important driving force for biomass gasification technologies and demonstrations.
5. Biomass-derived hydrogen is capable of addressing any current and future H₂ market. Produced by thermochemical routes via syngas, biomass-derived hydrogen can yield H₂ purities comparable to those achieved by steam reforming of natural gas. Although today's prototype polymer electrolyte (PEM) fuel cells may require hydrogen of higher purity, there should be no limit to using H₂ from biomass in the next generation of PEM fuel-cell vehicles, which are widely expected to reach the market in 10 to 15 years

* Other renewable sources, such as wind, could also contribute to renewable hydrogen production in the near term, but represent an “indirect” route because they proceed via the production of renewable electricity and electrolysis.

6. Co-gasification of biomass with fossil fuels, such as coal, would extend drastically the scope for using and processing biomass to hydrogen. Access to this mainstream, high-volume part of the energy business would give improved biomass economies of scale, reduce the need for dedicated biomass processing and transport, and allow important application synergies. Most interesting is co-gasification of biomass in large integrated gasification combined cycle (IGCC) plants. This flexible *polygeneration* technology can be readily optimised for producing hydrogen along with power, heat and other products including concentrated CO₂. Co-gasification via IGCC, a flexible process that can adapt to a wide range of biomasses and feeding percentages, would allow capitalising on the maturity of entrained-flow gasification, a commercial process for fossil fuels.
7. The issue of *scaling* is particularly challenging for processing of biomass to hydrogen. Two contradictory sets of scaling criteria must be satisfied simultaneously: those of the biomass supply-chain logistics, which is inextricably linked to the place it is harvested; and those of gasification, technologies that need huge volume in order to be economic. Logistics limit biomass collection to a certain distance from the plant; conversely, large gasification plants are needed, e.g. processing a minimum of 0.5 to 0.75 million tons of dry biomass per year. Solving this scaling problem requires a careful optimisation of total value chains, and consequently, of the process technologies. Neither locating the processing plants in areas of e.g., large plantations, nor transporting raw biomass over long distances, are realistic alternatives because the resulting total processes lack any serious commercialisation potential.
8. An “integral / split” approach is a conceptually logical way to solve the scaling problem. A single value chain – thus, an integral process – is retained, but is split temporally and spatially. In or near the harvest area, biomass can be pre-processed into a *secondary* energy resource in small to medium-scale facilities, using relatively simple technology. The resultant “biomass carriers” are tradable goods, which can be transported like coal or crude oil, and processed via syngas in large gasification plants located near major markets – thus making full use of economies of scale where it is most relevant.
9. An attractive path to market penetration exists in the pre-processing of agricultural by-products by flash pyrolysis techniques. These satisfy the requirement above by being relatively simple and apparently competitive on a modest scale: 20,000 – 200,000 t/a. Plants in the lower end of this range are already commercial, several processes exist. Such plant may be located in an area with available biomass, and the pyrolysis oil can be transported as a liquid for processing in larger gasification plants.
10. There are important synergies with other uses for biomass-derived synthesis gas such as second-generation liquid biofuels, which could accelerate developments and reduce market introduction risk. Synergies could take the form of processing H₂-rich streams primarily to liquids – fuels or chemicals – or introducing biomass-derived hydrogen into existing non-energy markets. The majority of technical and operational hurdles of biomass processing, gasification and product optimisation would be shared between both types of applications. Possibly, plants could be designed for output flexibility without compromising efficiency.

Gaps have been identified in the understanding of

- biomass – feed handling, in particular logistics aspects
- pyrolysis oil – variability of composition, affecting processing and gasification
- gasifier – optimisation of operational reliability when co-processing biomass fuels
- scaling – lack of criteria for assessing spatially/temporally split processes
- management of ashes from co-gasification plants

R&D needs

Development is needed to improve the economics of biomass thermochemical production processes and the logistics of feedstock. In particular concerning

- Feed preparation – characteristics of feedstocks for allowing technologies to develop
- Biomass gasification: implications of co-processing; fuel standardisation criteria
- Properties of selected tradable fuels (“biomass carriers”) in view of co-processing
- Gasifier gas handling and clean-up, best practices for operation on mixed fuels
- Relationship of production scale/fuel quality requirements and variability tolerances that can be accommodated for respective technology options
- Interfacing” issues (front-end, back-end) and systems integration
- Information dissemination and policy implications for biomass and hydrogen

Recommendations

- A new IEA Task addressing hydrogen from biomass should be defined under the Hydrogen Implementation Agreement
- This could focus initially on near market opportunities at a small to medium scale, covering both Europe and major biomass producing countries in other parts of the world who could be stakeholders in the future hydrogen economy.
- Industrial players should be directly involved in contributing to guide the activities.
- The key R&D challenges and non-technical hurdles to address in the context of a new task can be identified now, without need for further studies, because so much material has been made available from various international collaborative activities.
- Co-gasification of biomass with coal should be included in the new Task, the work to be done focusing on key issues of hydrogen from biomass while communicating and coordinating with IEA activities on GHG reduction, bioenergy and clean coal.

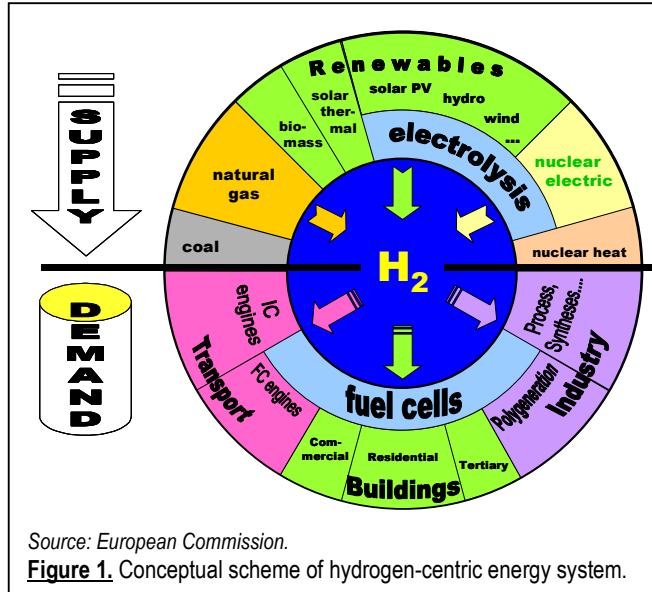
Reference cited in Summary

¹ D. Gielen, G. Simbolotti et al: *Prospects for Hydrogen and Fuel Cells.*, IEA Energy Technology Analysis series Vol. 2; International Energy Agency, Paris, November 2005.

Section I – MARKETS

I.1. Hydrogen: Drivers and Scenarios

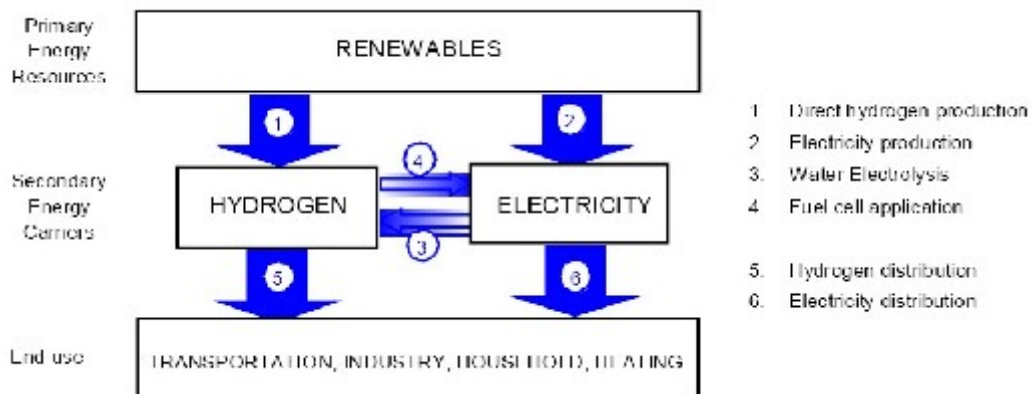
Introducing hydrogen as an energy carrier is of major strategic significance, because hydrogen enables a different approach to managing the entire energy system. The key is the diversity of production pathways for hydrogen and its flexibility of use in all demand sectors, coupled with the anticipated arrival of high-efficiency energy conversion tools such as fuel cells. A hydrogen-centric energy system, as illustrated conceptually in Fig. 1, potentially allows *any* energy source to supply *all* markets and applications; in transport, industry, buildings and homes. In particular,



- Hydrogen, unlike electricity, is a *fully storable* energy carrier; this flexibility allows a temporal split of the production of energy from its use.
- Hydrogen differs from all chemical energy carriers such as coke, propane, or petrol (gasoline) in being *independent of any single source or route of production*.
- Unique among fuels, hydrogen offers *zero carbon emissions* at the point of use.

Thus, whereas all other elements of a solution to global energy needs – renewables, biofuels, carbon capture & sequestration, cleaner coal... – are basically *sectorial* in nature, representing potential solutions to *parts* of the problem, hydrogen is key to realising the *systems benefits* of sustainable energy. These advantages, taken together, make hydrogen the ideal complement to electricity in a future energy system built on renewables and other emission-free sources.

Figure 2. The interplay of hydrogen & electricity as carriers in the energy system. (source: Hydro).



However, it is precisely this versatility of producing and consuming H₂ which also means that introducing it on the energy market will not lead automatically to lower emissions of greenhouse gases, or indeed to reduced consumption of fossil energy. For these objectives to be achieved, hydrogen must be obtained from sources – and by processes – which are more sustainable in the global context than those hydrogen will compete with. It follows that *carbon-lean* (ideally, *carbon-free*) pathways must be favoured for H₂ production*.

Taking a pragmatic, market-driven approach to the various hurdles of introducing hydrogen, the implication is to primarily search for those pathways – using renewables and/ or other sources of energy – that cannot by other established means be used efficiently to improve the energy mix in terms of GHG emissions, security and diversity of supply, and local air pollution.

Among renewable energy sources, biomass is unique in offering a relatively straightforward direct route to hydrogen. Several thermal conversion technologies exist that could be developed towards commercialisation without need for any major scientific breakthroughs. Some biological and other chemical pathways to H₂ from biological sources also show promise, and are subject to intensive research worldwide.

The advantage of direct conversion from a renewable source (without entering the debate on how to best use RES-generated electricity) makes biomass a strong candidate for the early introduction as a relatively abundant source of “green” hydrogen. Care must be taken to select, adapt and develop technologies for biomass-to-hydrogen so that the maximum overall impact can be achieved. Certain biomass resources may be used to a greater effect, or at least more rapidly, for generating electricity and heat, or as feedstock for next-generation liquid biofuels. On the other hand, there may be large sources of biomass and wastes available both locally and globally that could be used to produce hydrogen-rich gases.

The purpose of this report is to review the available technologies for producing hydrogen from biomass, assess their application potentials, and analyse gaps and needs, especially for R&D. The technical focus is on thermo-chemical processes, in particular gasification.

* Because of the systems nature of hydrogen, it does not follow from such an analysis that only “green” hydrogen should be encouraged; at least not in the early phases of market introduction. This is because of the effects of volume and economies of scale. Current energy markets are heavily biased in favour of conventional sources of energy, e.g., fossil, and established distribution such as the central power grid. Hydrogen needs a certain “critical volume” (a few per cent of the energy market) to begin unleashing its systems effect. Incentives and market-facilitation measures must be designed to allow hydrogen energy to achieve a competitive start position at the earliest possible point on the market uptake curve. Initially, incentives must be independent of how the hydrogen is produced, not limited to “renewable” hydrogen, because the effect of volume is so critical (Italy’s “*Marzano law*” is an example of legislation recognising this). In the more level playing-field that emerges as hydrogen energy starts to be a serious alternative, market mechanisms, especially economics of scale, will reinforce this trend and allow RES to compete as sources of hydrogen, i.e. on a very different basis from today. The enabling factor in this process is the versatility of hydrogen - and biomass is well placed to be the first RES to benefit from it.

1.2. Markets, value chains, phases

Hydrogen derived from biomass sources can in principle access any current or new H₂ market as long as the product meets relevant customer requirement in terms of volume, purity/grade, cost, deliverability and consistency of supply (*i.e.*, seasonality, compositional variations...). The challenges of complying with specific requirements of each sub-market and segment depend primarily on the source of the biomass and the processes used.

The main markets discussed in this report are those associated with the future use of hydrogen as an energy carrier. Estimates of the size, timing and other characteristics of this application vary widely, but it is generally accepted to be a long-term prospect. As a general backdrop, this report takes the scenarios developed by the IEA Hydrogen Coordination Group presented in a recent monograph ¹ and, for more specific information, the European Hydrogen and Fuel Cell Technology Platform ², noting in referring to the latter that the pace and scale of market growth in regions such as South and East Asia (Japan, China, Korea, India, Singapore) may be faster, due to characteristics of their energy and fuel markets. In all regions, the hydrogen markets are expected to be driven primarily by the demand for a clean transport fuel, with important secondary demand contributions from stationary applications such as the distributed generation of power and heat in domestic and other contexts.

Within this context (*cf.* Fig. 1), conversion of biomass is the only direct route RES to hydrogen which draws only on existing, reasonably well-established processes and technology elements. Other renewable hydrogen pathways, of immense future potential, remain at an R&D/proof of concept stage, or require the conversion of renewable electricity to hydrogen via electrolysis.

Biomass being a “green” resource, with advantages in markets where customers or authorities will pay for the avoidance of CO₂ emissions, other energetic outlets will compete with the use of biomass for hydrogen. Assessing all competitive applications of biomass in a comprehensive manner is beyond the scope of this report. However, because of our focus on thermal biomass conversion and especially gasification, a discussion and a brief competitive-synergistic analysis is provided on the use of biomass-derived synthesis gases as a feedstock for biofuels as well as non-fuel chemical products.

How hydrogen energy markets might develop is a subject of intense discussion. Most informed observers however agree that distinct sub-markets will probably develop and that these can be best analysed in terms of the developing market maturity, rather than trying to guess any fixed time scale. For the purpose of this report, a suitable classification into sub-markets could be:

- A. Hydrogen for use as a blend with other gases
- B. Hydrogen used in combustion (any application)

- C. Hydrogen for conversion to electricity and heat in *non*-PEM stationary fuel cells
- D. Hydrogen converted in fuel cells for *non*-road transport
- E. Hydrogen converted in PEM fuel cells for road vehicles (*pre-commercial test market*)

- F. Hydrogen converted in stationary PEM fuel cells (*its major stationary energy market*)
- G. Hydrogen for fuel-cell powered road vehicles (*its major transport energy market*)

Some remarks:

- These are markets for hydrogen in the form of compressed H₂ gas (or liquid) but sub-markets A through D might conceivably also use hydrogen-rich mixed gas streams;
- Submarket C includes molten carbonate and solid oxide FCs (MCFC, SOFC);
- Submarket D would include fuel cell use in ships, trains and light rail systems
- Submarket G only starts with the roll-out of series-produced fuel cell cars;

Note the distinction between developmental and post-rollout markets for road vehicles (E vs. G) – this is of some importance, *e.g.*, in assessing purity requirements, and hence has a bearing on the potential role of biomass. (See box below).

The suggested list is not exhaustive; *e.g.* APU's for the various means and modes of transport would be a cross-cutting category. Note that these are sub-markets seen from the point of view of hydrogen supply. When seen from the perspective of an end user or fuel cell supplier, each of our sub-market would present a number of *segments* or *niches*. As an example, sub-market F would in this perspective have at least 3 segments in power class "less than 1 to a few" kW:

- portable power generators (sometimes quoted as an early fuel-cell market);
- back-up/emergency power supplies; and the one many expect to be dominant;
- fuel cell co-generation (micro-CHP) appliances for domestic (residential) use.

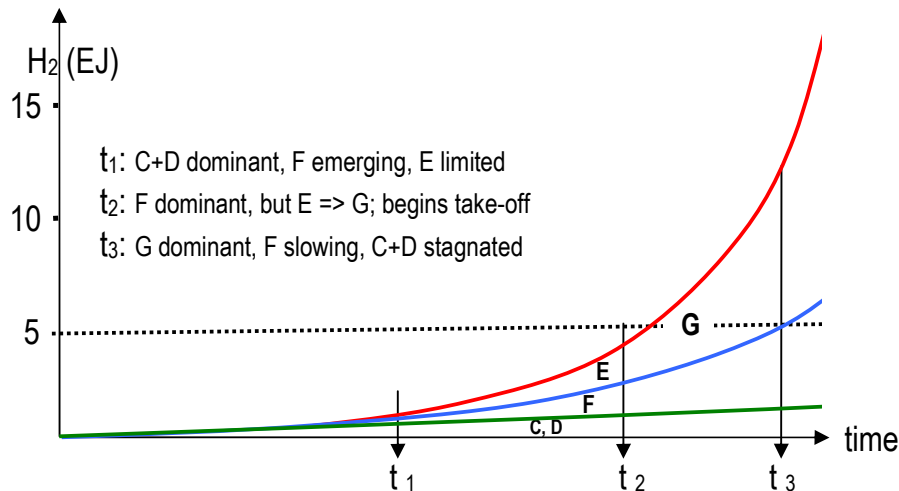
Clearly, in this example these three represent very different applications for a fuel cell supplier in terms of the market size, timing and introduction strategy. However, of prime importance for our purpose is the likely case that they will need H₂ of similar purity and volume per unit.

Sub-market G, beginning with the roll-out of FC vehicles, is the last, ultimately biggest market. Most observers expect polymer electrolyte (PEM) fuel cells to be used – but importantly, these are not necessarily identical to the PEM technologies of today. Significant breakthroughs, both in terms of robustness and cost, are required before fuel-cell engines will be adopted for serial production by the automobile industry, which implies necessary technical and design changes. Importantly, for the purpose of our assessment of hydrogen markets, this means that the fuel specifications quoted today by PEM fuel cell developers and component suppliers could have little relevance to the actual situation 10 or 20 years ahead. As it is unrealistic to assume mass distribution of hydrogen fuel in ultra-pure form, the purity achievable by established processes, *i.e.* natural gas reforming, can also be taken as the specification guideline for hydrogen fuel as distributed to the end user.

The size and relative scale of each sub-market will vary with the overall market uptake curve as sketched in **Figure 3**. Note the change in relative importance of each sub-market as the global production grows. The horizontal dotted line indicates the volume of hydrogen produced today.

Existing (non-energy) markets for H₂ will continue to be important even in the most accelerated scenarios of introducing hydrogen as fuel, as the need of refineries for hydrogenation continue to grow as hydrocarbon fuel specifications are tightened in most markets. Also, the availability of a "green feedstocks" for *e.g.* fertiliser, ammonia, methanol or other globally traded chemicals produced from syngas will likely be of growing future importance as the industries concerned are affected by emission restrictions, CO₂ taxes or compulsory quotas trading. These markets are not taken into account in the picture illustrated by Fig. 3, but are referred to in the report at appropriate points.

Figure 3. Anticipated generic uptake curve for a hydrogen energy market development with the key sub-markets indicated.



Explanation: C and D are early markets. At the time t_1 they dominate demand, which is still small: just a few % of the non-energy H_2 . However, market F is gaining importance, and grows until at t_2 it exceeds C and D combined. Soon, the volume of energy H_2 exceeds all non-energy H_2 markets. Meanwhile, E has grown into a visible test market. As FCV's are rolled out, it transforms into G, a mass market, and takes off. At t_3 , the C and D markets are just a minor part and G dominates the growing H_2 demand as market F also begins to saturate. **Moral:** such a market looks very different to the unknowing observer before time t_1 and before t_2 , and it is not obvious what stimuli to apply in order to achieve a desired growth path. **Note:** The black dashed line represents current hydrogen demand at about 5 EJ; at t_3 , the 12.4 EJ of H_2 produced is enough to supply the 30% of a global vehicle fleet that consists of highly efficient FCV's. (See ref. 1 sec. 7 for a scenario background).

Key point: The markets for hydrogen as an energy carrier are as diverse as its applications, and will build gradually, such that the importance of each sub-market changes with maturity.

In this simplified assumption of future markets, hydrogen from biomass could address

- combustion markets A and B immediately, if these offered a concrete demand today;
- submarket C – although in direct competition with natural gas as the reference fuel for both high-temperature FC technologies (molten carbonate & solid oxide) as of today;
- markets D and E, noting that these are in the near future likely to be limited to isolated demonstration projects where it is opportune to feature a fully renewable supply chain;
- markets F and G, in competition with other hydrogen production routes for distributed as well as centralised supply; perhaps with a slightly more favourable starting position in the centralised case (see discussion on economies of scale in later chapters).

Some observations on market building

A frequent argument in the debate about renewable sources for hydrogen is that the amounts of biomass available are too small to alone secure a sustainable supply in the context of a fully developed hydrogen energy system. While this may be true (as discussed later in this Report), the issue is not very relevant even in the medium term.

Applying the *crash-barrier principle* as used in sustainable development theory, hydrogen from biomass has to pass through – “crash” – a number of barriers before resource availability will become the limiting factor. Referring to Fig. 4 below (originally applied to solar energy, but in principle equally applicable to hydrogen and fuel cells), four distinct phases can be identified, each relating to the passage through a specific barrier:

Phase 1: Technology cost is high; expansion requires preferential investment support

Phase 2: Prices have become competitive, but production capacities are limited

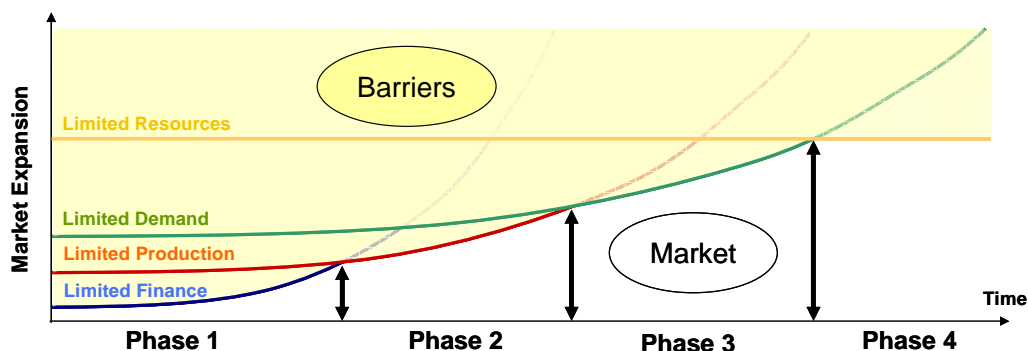
Phase 3: Production catches up, and the market is defined by demand

Phase 4: As demand grows, the availability of resources may become limiting

This applies, in fact, to any source of hydrogen, and the issue of biomass availability should be addressed at an appropriate stage – notably, within a given scenario and with full recognition of market behavior and the experience gathered in the course of passing all preceding barriers.

The role of market building through organic growth cannot, therefore, be overestimated. This is the concept used in many future scenarios – with demand for hydrogen energy starting in a few isolated spots, each with a filling station and perhaps a few buildings supplied from an on-site source, and then gradually linking several such sites, ultimately growing a distribution network (e.g., pipeline). In this scenario, the learning processes about each barrier can be implemented in a gradual way, a process which will add immense real world experience.

Figure 4. Barriers to market expansion, illustrating the crash-barrier principle.



Source: DLR³.

Key point: Hydrogen from biomass – like hydrogen from other sources – has many barriers to “crash through” before resource availability becomes the limiting factor.

1.3. Biomass energy

Biomass is humanity's original source of energy since fire was tamed and was our chief source of energy for millennia: as recently as the 1920's more than half of world demand was satisfied by biomass, mostly wood. Today, 11 % of world primary energy demand is met by biomass, but nearly 70% of that is from the use of traditional fuels in poor countries. Nearly 2.4 billion people depend upon wood, agricultural residues and dung as the only energy for cooking and heating – usually collected and used by unsustainable means with strong negative impact on people's daily lives. This is a major global problem preventing economic development and causing death and disease by indoor air pollution⁴. Energy statistics previously excluded traditional biomass, but IEA *World Energy Outlook* now lists non-commercial biomass at 20% of primary demand in developing countries. Their traditional biomass use will keep growing, from 765 Mtoe in 2002 to 907 Mtoe in 2030, although its *share* in primary energy demand will at last begin to diminish.

Figure 5. Sustainable biomass energy cycles



Biomass used in a sustainable way is on the increase, and is predicted to surpass 75% of traditional biomass use by 2030 at almost 700 Mtoe⁵. Biomass is a renewable resource, and is a form of indirect solar energy since most of it is derived from sunlight via photosynthesis.

The term “biomass” includes all biodegradable fractions of products, residues or wastes from agriculture and forestry (vegetable and animal substances), and the biodegradable fraction of industrial and municipal waste. In a renewable energy perspective, biomass can be defined

as recent organic matter of plant origin produced by photosynthesis; or from animals, that is used to provide energy in the form of heat, electricity, or fuels.

Here, “animals” include humans, and “recent” refers to short cycle carbon, to distinguish bio-energy from fossil fuels or peat where carbon has been removed from the short cycle. Fig. 5 shows the cycles in the upper part and a modern biomass energy chain below.

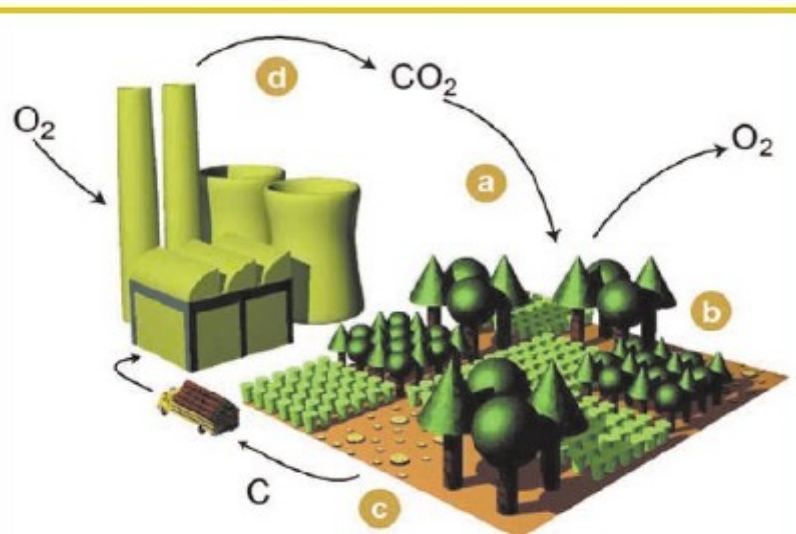


Figure 5: An illustration of the recycling of carbon as biomass accumulates in energy crops and forests and is consumed in a power station. a: CO_2 is captured by the growing crops and forests; b: oxygen (O_2) is released and carbon (C) is stored in the biomass of the plants; c: carbon in harvested biomass is transported to the power station; d: the power station burns the biomass, releasing the CO_2 captured by the plants back to the atmosphere. Considering the process cycle as a whole, there are no net CO_2 emissions from burning the biomass. (Source: Matthews, R. and Robertson, K. 2002)

Characteristics of biomass and its path to energy markets

There are three main categories of biomass: *woody*, *non-woody*, and *animal & human waste*. Common sub-classifications are forests, woodlands and forestry plantations, agro-industrial plantations, trees outside forests/woodlands, aquatic plants, agricultural crops, crop residues, processing residues, and animal wastes. Municipal bio-wastes including landfill gas are also regarded as biomass resources, as is the biodegradable fraction of municipal solid waste.

The main source of *woody biomass* is forest residues, including leftovers from production and processing of timber by forest industries, such as thinnings, forest arisings, prunings and wood process residues. Woody biomass can also be grown directly as energy wood. Short-rotation energy forest plantations can be harvested every 2-10 years, depending on the species, soil properties and climate. Typical SRF species include willow, poplar and eucalyptus.

Non-woody biomass resources include agricultural crop residues and dedicated energy crops. Common crop residues are straw from various grain crops, rice husks, bagasse, maize cobs, coconut husks, coffee husks etc. Many traditional food crops can also be grown specifically as energy crops. These include sugarcane, maize/corn, wheat, sorghum and vegetable oil-bearing crops, e.g., sunflower, rapeseed and soya beans. These are converted by chemical processing into liquid fuels such as ethanol or biodiesel.

Animal and human wastes are also bioenergy resources. Commonly used animal wastes are manures from pigs, chickens and cattle. The manure is converted into biogas via anaerobic digestion. Municipal and domestic sewage sludge can be converted into biogas in the same way. Municipal biological waste ("green waste") can be combusted or treated biologically to produce energy. Also industrial wastes especially from food processing industry and fibre industry can sometimes be used as bioenergy sources.

The properties of biomass as a fuel vary considerably, even for wood arising from the same plantation. The properties of the biomass source determine both the choice of conversion process and subsequent processing difficulties. The main properties of interest are: moisture content, calorific value, proportions of fixed carbon and volatiles, ash/residue content, alkali metal content and cellulose/lignin ratio.

Bioenergy is particularly suitable for regional or local application where sufficient and affordable biomass resources are available, especially in countries with few fossil energy sources. Equipment and services for the exploitation of biomass from forestry, agriculture, or dedicated crops, can have considerable positive impact on employment, especially in rural areas. Importantly, biomass can be used in a variety of applications across most of the use spectrum that fossil fuels now fill, in most cases as a CO₂-neutral alternative. Increasing oil and natural gas prices and concern for the long-term security of supply have stimulated interest in biomass energy. Today, the EU, US and many countries have in place ambitious support schemes to increase the supply of energy from biomass – electricity, heat, biofuels as well as industrial chemicals.

Some biomass to energy technologies, such as combustion, are already competitive in locally favourable economic circumstances, whereas others such as gasification and pyrolysis, still are in need of further advance to become marketable. However, with the possible exception of the current generation of bio-fuels, all bioenergy applications share four main application-related problem areas which need to be assessed individually in view of the need for market-oriented measures (technical and non-technical) to accelerate their penetration into the energy markets:

- a) the resource production, supply, upgrading to a fuel and the storage of the fuel,
- b) the feeding system and (except for bioheating) the conversion reactor,
- c) the environmental protection measures; and,
- d) the energy recovery for heat and/or electricity.

Thus, in summing up, the importance of underlying technological progress for the success of bioenergy in markets has been underlined as follows ⁶:

There has been continuous development of bioenergy technologies over the last few decades, with various degrees of acceleration during certain periods in time as a reflection mostly of the variations in the price of oil. Climate change offers the opportunity for long lasting policies for a constant support of bioenergy. For this to be achieved, bioenergy technologies have to demonstrate that they have reached the degree of maturity and reliability needed for the local but also global economy. Thus, in order for bioenergy to successfully penetrate the energy markets, it must reach similar degree of development with that of fossil fuels in order to provide the same quality of services to the consumers.

Two particular market niches, or more properly entry paths, for bioenergy, which have received attention in recent years are introduced in the next section: liquid biofuels and pyrolysis oil ^{*}. The technologies with which these are produced are discussed in Section II.

Liquid biofuels

Biofuels as used in transport are liquid or gaseous fuels produced from biomass and intended for the operation of vehicle combustion engines. The most common examples seen on today's market are biodiesel – usually produced from rape seed, sunflower seed or used cooking oils, and bioethanol – obtained from fermenting sugar beet, maize, barley or wheat.

World production of biofuels for transport is led by Brazil and the United States, both focused on bioethanol. In 2003, over 18.3 million tonnes of bioethanol were produced worldwide with Brazil alone at 9.9 million tonnes – over 20 times the EU production. All petrol sold in Brazil contains around 25% of bioethanol. The high production levels in Brazil and the US arise from their early adoption of biofuels driven by the desire to reduce import dependence and make use of the potential of their agricultural sector.

In Europe, biofuels currently have less than 2% of the total transport fuel market, but this share has risen progressively in the past decade. EU production of conventional biofuels – ethanol and biodiesel – was 1.7 million tonnes (1.5 million t.o.e.) in 2003. The figure represents about 26% growth over 2002, but is still far from the targets set in policy documents and the Directive on biofuels ⁷: 5.75% market share for biofuels by 2010. Preferences for biodiesel vs. bioethanol vary among EU Member States. Substantial production in the EU is envisaged but, at least for high demand scenarios, a large part of the biofuel is still likely to be imported. There exist recently published comprehensive documents describing further the EU biofuel effort ⁸.

^{*} Other methods for “densification” or pre-processing of biomass, such as torrefaction (“roasting”) of wood might also offer cost-, energy- and GHG-effective solutions; however, the present study is focused on pyrolysis oil.

Pyrolysis oil

Pyrolysis oil is one of humanity's oldest manufactured products; it was used in ancient Egypt for embalming the dead ⁹. More recently, fast (or flash) pyrolysis has been the subject of R&D as a promising process for the upgrading of biomass to marketable energy products and fuels. Many projects have been carried out on pyrolysis oils, and a wealth of information is available, e.g. on IEA Bioenergy and the *PyNe* international network ¹⁰.

In the 1990s, several fast pyrolysis processes achieved a near-commercial status, developed principally by two Canadian companies and by BTG in the Netherlands. One commercial plant is in operation, of nominal capacity 50 t/day, operated by Canadian company Ensyn in a close partnership with a US food additives manufacturer, whose "liquid smoke" products is the only commercial market for flash-pyrolysis oil today. The viability in this particular case appears to depend on a close integration of the food additive and (on-site) fuel usages. Other developers are in the pre-commercial stage: DynaMotive of Vancouver has demonstrated a bubbling fluidized bed process at 10 t/day of biomass and subsequently built a 100 ton/day production unit in West-Lorne, Canada. The sawdust derived pyrolysis oil is partly used in a modified Orenda gas turbine. BTG (The Netherlands) operates its own developed rotary cone reactor at a nominal capacity of 6 t/day (250 kg/h). In 2005, a first production unit was built in Malaysia converting Empty Fruit Bunches from palm processing into pyrolysis oil. Several others have constructed pilot plants, e.g. that of Fortum in Finland (12 t/day, in the EU co-sponsored "Combio" project). Yields and properties of the liquid product, pyrolysis oil or "bio-oil", depend on the feedstock and the process type and conditions. Extensive data are available ¹¹.

Pyrolysis oils so far have not been generally accepted as fuels, not even for stationary engines where they are technically easier to employ than in vehicles. Developments of pyrolysis oil applications have been limited, mainly due to a lack of sufficient and consistent pyrolysis oil. An important handicap is the fact that pyrolysis oils are not miscible with conventional liquid fuels; another is concern about corrosiveness. Even as fossil fuels increase in cost, such handicaps may remain also towards both current and future liquid biofuels (bio-diesel, ethers and ethanol)

Gasification of pyrolysis oil has been investigated at several companies and institutes around the world, e.g., Future Energy and UET, Germany; NREL, US; BTG, the Netherlands. Syngas production is normally carried out at elevated pressure, so a liquid has the advantage that pressurizing it is much easier and cheaper than pressurizing solids. Due to the absence of minerals, also non-slugging gasifiers are possible to use (residue gasifiers), or even catalytic conversion.

Cost estimates for pyrolysis oil indicated are less than 100 €/ton. This compares well to another established biomass-derived product: tall oil, used as a versatile feedstock for many decades in various industries. Tall oil, typically trading at 100 - 200 \$/ton, is a by-product of Kraft pulping processes with a stable, diversified world market of more than 1.5 million tons/year. However, pyrolysis oil is likely to remain more expensive than black liquor, also derived from Kraft pulping – this is not a traded product, but currently sees a lot of attention as a potential feedstock.

1.4. Market scales & logistics

How much biomass is available?

Estimates of the total volume of biomass resources available, and hence of potential markets for the various forms of biomass energy worldwide, differ widely. Of even greater uncertainty are estimates on how much of the resource that is technically and economically feasible to use. Total world primary energy demand in 2002 was 10.3 billion tons oil equivalent, corresponding to 431 EJ. Demand is expected to grow by almost 60% to at least 690 EJ by 2030, see below.

Table 1. World Primary Energy Demand (Mtoe)

	1971	2002	2010	2020	2030	2002 -2030*
Coal	1 407	2 389	2 763	3 193	3 601	1.5%
Oil	2 413	3 676	4 308	5 074	5 766	1.6%
<i>Of which international marine bunkers</i>	<i>106</i>	<i>146</i>	<i>148</i>	<i>152</i>	<i>162</i>	<i>0.4%</i>
Gas	892	2 190	2 703	3 451	4 130	2.3%
Nuclear	29	692	778	776	764	0.4%
Hydro	104	224	276	321	365	1.8%
Biomass and waste	687	1 119	1 264	1 428	1 605	1.3%
<i>Of which traditional biomass</i>	<i>490</i>	<i>763</i>	<i>828</i>	<i>888</i>	<i>920</i>	<i>0.7%</i>
Other renewables	4	55	101	162	256	5.7%
Total	5 536	10 345	12 194	14 404	16 487	1.7%

Source: IEA World Energy Outlook 2004. **Note:** 1 EJ = 23.88 * Average annual growth rate.

Very high estimates are obtained for the technical potential for biomass to energy production if dedicated energy farming is included. A review study by Faaij, Dielen et al ¹¹ reviewed the past work and concludes that biomass potentially can provide a very large contribution to future world energy supply even exceeding present world demand. Their work is a complex analysis, but an example calculation from it is straightforward and quite illuminating. It proceeds in three steps: (i.) needed land for production of food, (ii.) resultant yield of energy crops grown on remaining land, and (iii.) conversion to useful energy. In the box below is given a synthesised summary calculation made from the GRAIN study – all responsibility for the synopsis is ours, not theirs.

i. Area: For production of biomass one needs land. The world land area includes 5.0 billion hectares of productive land (agriculture & pasture) (38% of total land area). Assuming this area remains available, and using applicable best practices for food production, the amount of land needed to grow food for a world population of 9.4 billion in 2050, on an “average” diet (neither vegetarian nor especially protein-rich), is readily calculated. Depending on a number of factors, especially the degree of “external input” i.e. use of fertilizers pesticides etc. (“intensive” versus “organic” farming), this leaves between 640 and 3160 million hectares available for growing energy crops.

ii. Yield: A conservative estimate of the yield for perennial crops, e.g. willow, eucalyptus or miscanthus, is 8 to 12 metric ton (oven-dry material) per hectare per year with a (lower) heating value around 18 GJ. Net production is about 5% lower due to loss for fertilisers, machinery etc. 1 ha can thus produce 140 - 200 GJ from energy crops.

iii. Result: Producing 1 EJ per year requires 5 to 7 million hectares. One thousand biomass combustion power plants of 600 MWe capacity each, in base load (ca. 7 000 full load hours per year) with 40% efficiency need an energy input of 38 EJ / year, needing 190 – 260 million hectares of land. These would produce (at 40% efficiency) with minor net CO₂ emissions, about 15 EJ gross usable electricity, or 4200 TWh.

To compare: the United States generated 4150 TWh electricity in 2004; the world 17 452¹². Obviously, there are very large uncertainties associated with scenarios of this kind even in a long-term perspective. The largest stated uncertainties in the case of the review mentioned are the degree of intensive farming used and – perhaps surprisingly – the animal protein content of people's diet. Nevertheless, similar conclusions can be reached for e.g. the EU by analysing the state of its agricultural situation – in that case by proposing that land currently not used, or not needed to satisfy the EU-27 food supply, instead be dedicated to energy crops. Obviously, using set-aside lands must be carefully analysed for environmental impacts and GHG reduction benefits. A recent report from the European Environment Agency addresses this issue¹³.

Other ways of valorising such crops than to produce electricity by simple combustion plants can be readily envisaged, with calculations for a complete hydrogen economy based exclusively on biomass perhaps an extreme case¹⁴. The US Department of Energy published a study in 2005¹⁵ that showed the technical feasibility of displacing more than a third of United States demand for transport fuel by producing approx. 1.3 billion tons of biomass. Brazil's ethanol fuel industry shows that such grand schemes may even work.

Energy crops aside, China has in principle available today, across its countryside, vast biomass resources which could be used for energy on a massive scale, on the order of 1 billion tonnes per year, two-thirds of it being crop residues¹⁶. This corresponds to more than 350 Mtoe/year – or nearly 4% of world primary energy demand and of the same magnitude as China's own consumption of coal, the country's number one energy source. Prior to the 1990's, crop residues were the main fuel in rural areas, a portion of it processed in thousands of "village gasifiers"; however with rapid industrialisation and spread of fossil power sources, these residues are used less today – often being simply burned in the fields.

For long-term prediction, as for example in the recent IEA hydrogen scenarios¹, a pragmatic estimate is that about 200 EJ per year of primary biomass could be made available by 2050. This includes about ¼ of energy plantations on marginal and arable land added to a mix of the other categories available today. The same study assumes a total primary energy demand from 785 to 865 EJ in 2050, so biomass could at that time deliver a quarter or more of global energy supply. Compare with 2002 figures of 47 EJ (but just 15 EJ of that being modern biomass).

The importance of such "high – but not impossibly so" long-term estimates for our purposes of discussing biomass as a source of hydrogen, is that they point forward to a quite feasible future increase in biomass supply as and when hydrogen demand takes off – refer to Figure 3 for the case where sub-markets F and G start absorbing large amounts of hydrogen. Energy farming even on a small percentage of arable land could lift completely the "resource barrier" of Fig. 4.

A nearer term perspective is taken by the EU, which already has in place policies and targets for renewable energy sources – both for their share in overall energy supply and in electricity generation. In December 2005 the European Commission adopted its Biomass Action Plan¹⁷. The main objective is to double by 2010 the share of bio-energy sources (wood, wastes, and agricultural crops) in the EU's energy mix.

Currently, the EU meets 4% of its energy need from biomass. The plan outlines 31 measures to promote biomass heating and cooling, generation of electricity, and biofuels in transport. Successful implementation would reduce the share of fossil fuels in the EU's energy mix from 80% to 75% and 8% less crude oil would have to be imported resulting in 209 million tons CO₂

equivalent lower greenhouse gas emissions per year. Thorough reviews of the technical and economic potential are available for the EU-27¹⁸.

From biomass residues for transport fuel markets

Agriculture and forestry generates residues, which can be used as by-products or must be disposed of (wastes). Like the total biomass numbers, those provided on potential for energy from residues must be considered with care, as there is little consensus among attempts to estimate global production and use. Also for residues, a wide range of estimates for residue is reported, varying from 20 up to 200 EJ¹⁹. Some of these are documented in Table 2 below. Variations in the data are mainly due to considerations of soil degradation impact and on the share of plant residues that should remain on the soil so as to maintain in the soil a sufficient level of organic matter that directly controls its fertility.

Table 2: Estimates of agricultural residues potentials

Authors	Potential	Remarks
Smil 1999 ²⁰	3.5 - 4 Gt 65 EJ	crop residues
Hall et al. 1993 ²¹	- 38 EJ	world's major crops (wheat, rice, maize, barley, and sugar cane), 25% residue recovery rate
BTG 2005 ²²	1.3 Gt 13.3 EJ	practical potential based on FAO data and specific assumed recovery rate for residues

BTG's number in this table is corroborated by a simplified analysis by Dinjus, Henrich et al²³ who obtained a figure of 3400 TWh or 12.2 EJ by a calculation on the average areas and crops, and average (as opposed to crop specific) recovery rates. Hence it does appear that a realistic and, notably, conservative near-term estimate on the order of 12 to 14 EJ of biomass available per year is realistic for our purpose. Looking only at residues, which in many countries are not used – or at least, used inefficiently, is seen as a more pragmatic way of attempting to source feedstock for hydrogen in the near term.

This is a significant quantity of biomass: 13.3 EJ corresponds to more than the 2003 final inland energy demand in all South East Asia – Indonesia, Malaysia, Singapore, Philippines, Thailand and Vietnam – plus Australia and New Zealand; it is nearly 90% that of Japan (15 EJ)²⁴. The EU-25 final energy demand in 2002 was 45.2 EJ. It corresponds to more than 317 Mtoe/year, sufficient to produce 150 to 180 Mtoe/year equivalent of hydrogen fuel. (see Section II for the documentation of processing efficiencies of 50 to 60%).

In terms of hydrogen from biomass, it is illustrative to compare the amount of recoverable crop residues with transport fuel demand in affected parts of the world (Most scenarios project that in a fully developed hydrogen energy system, at least half the volume of hydrogen is used in the transport sector.) In addition to the above data from the EU Biomass Energy plan are used.

In the EU and Japan/Pacific regions, transport represents about 28% of total energy use and is approximately constant in the period 2000-2030, reflecting modest growth expectations and a generally high focus on fuel-efficient vehicles. In contrast, for South & East Asia, the share of transport is projected to grow from 14 to 18% of total energy demand, reflecting the more than doubled transport fuel consumption per capita (from 0.08 to 0.19 toe/cap/year). Nevertheless,

energy demand from transport would be several times higher if similar per capita figures were reached as in the two developed regions (0.71 and 0.80 in 2000, respectively).

Table 3. Scale of residual biomass and potential energy carrier markets. All in Mtoe.

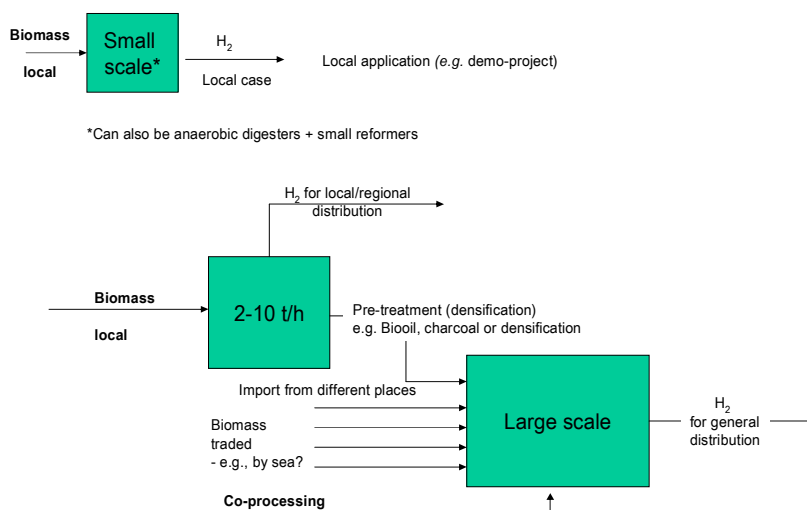
	2010	2020	2030
W. Europe Biomass production potential (of which non-forest energy crops)	186-189 43-46	215-239 76-94	243-316 102-142
W. Europe transport fuel market *	350	369	380
Conservative world estimate yearly (12-15 EJ of crop residues alone)	300 – 350 Mtoe (could yield 150 – 180 Mtoe of H ₂)		
Japan & Pacific transport fuel market	136	144	152
South and East Asia transport fuel market	423	613	832

(sources: WETO-2030 ; Alternative Fuels CG; EU Biomass AP) * 87% of this is road transport fuels

The “optimistic” figures for Europe confirm the conservative nature of our estimate for biomass residues. Note that the strong expected growth in transport fuel demand in South & East Asia. Even if a large part of world biomass resource potential is there (details, see the next section), the expected increase in demand for energy in this region risks quickly outstripping this supply, so that the share that can reasonably be covered by biomass residues could drop with time.

In contrast, Europe has a stable demand and the EU-27, being a major agricultural producer has its own sizeable biomass potential, which could cover a fairly large and growing share for transport fuel by 2030 – again, the growth is due to energy crops not residues. Note also that biomass energy could also be used as “new generation” liquid bio-fuels, not just in the form of hydrogen. However, once fuel cell vehicles were available, their better fuel economy per km driven would tend to favour hydrogen.

For hydrogen, local markets for biomass as a source would be expected to develop, typically in cities/areas committed to demonstrating a new system and where a “green” source of hydrogen is needed for a project to achieve citizen credibility and local political impact. Small-scale applications could be developed without major technical breakthroughs and excessive cost barriers (up to a certain level of performance) and would have certain advantages over, e.g. natural gas reformers in explaining the purpose of hydrogen to citizens and decision makers. See below.

Figure 6. Local, medium and large-scale concepts for biomass-to-hydrogen processing.

Importantly, the limitations of scale so far evident in biomass processing technologies – having their root in the resource's dispersed nature – may handicap biomass as a dominant supply route in a fully mature hydrogen economy. Other low emission sources would seem to have an advantage, such as coal with CO₂ capture and sequestration, e.g. by IGCC, or electrolysis with RES electricity, e.g. “non-dispatchable” wind power, or nuclear at night. Nevertheless, biomass could reach a sizable fraction of the total scale of a mature hydrogen energy market; in addition one should not ignore its critical role in the intermediate phases, as a direct RES-to-hydrogen option that is within reach of today's technologies.

In a more developed hydrogen economy, characterised by the onset of a centralised supply of hydrogen by pipelines linking local growth cores, a good option for biomass derived hydrogen would therefore seem to be co-gasification with fossil fuels, principally coal – and especially if CO₂ capture techniques are used. Besides the double benefit in terms of overall reduced GHG emissions, this would allow suppliers of biomass to feed into a much larger “pool” of hydrogen offtake streams than what can be realistically achieved going for biomass-dedicated large scale plant, thus helping to achieve the needed economies of scale for market competitiveness.

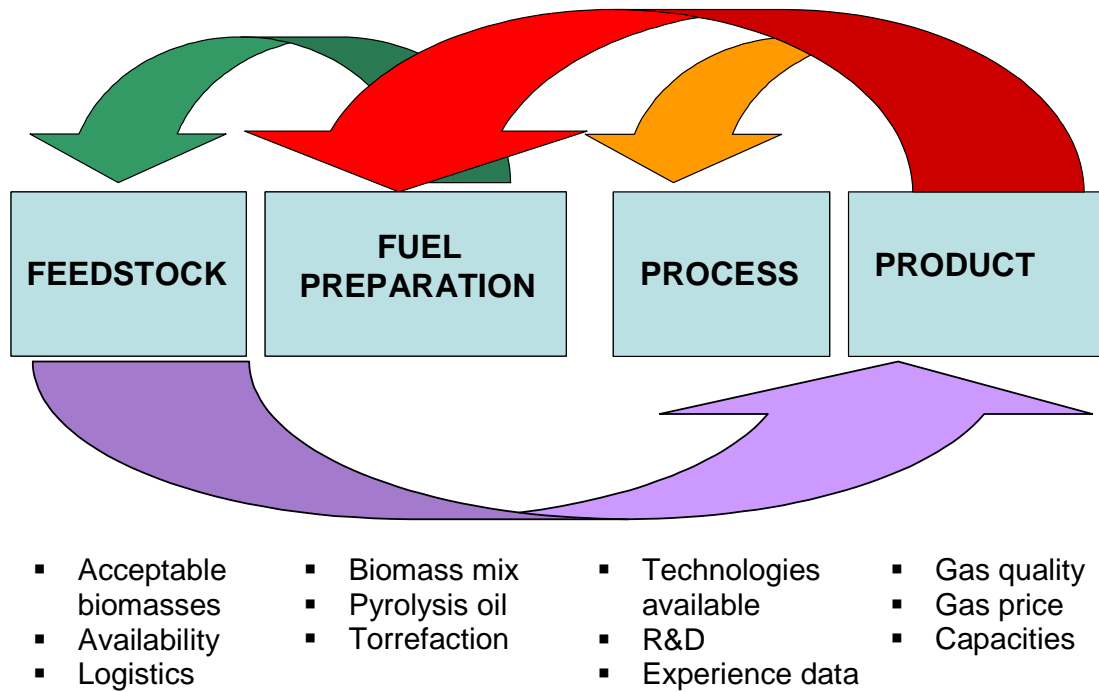
Logistics and size/scale effects

The role of feedstock and its availability is paramount in any market context for biomass. To be economically viable, hydrogen production from biomass relates to the nature, characteristics and availability of biomass in quantity required for the conversion process chosen. As biomass properties vary greatly in composition and form, detailed analysis of the value chain must be carried out when matching feedstocks with possible conversion technologies. These properties, particularly moisture content and ash content, are key parameters to consider for engineering any process concept. In addition, because biomass is a bulky product, so transportation costs would play a major role in the economic of the hydrogen production as too large plant that would reduce O&M cost through economy of scale would increase the feedstock cost and limit its feasibility. Therefore, localisation of hydrogen production plant requires specific attention to logistics on both transportation of hydrogen and feedstocks.

To determine the range of capacity of conceptual commercial processing plants it is important to take into account the different step of the process from the end use options, which will fix the requirements in terms of quality, prices and plant capacity, to the optimum feedstock with their specifications. Conversion technologies will be selected on the provision of the market requirements and the feedstock as illustrated in **Figure 7** below.

Hamelinck and Faaij²⁵ have assessed and compared the production from biomass of hydrogen and three promising liquid biofuels: methanol, ethanol and synthetic FT diesel. In their estimate they assumed 400 MW_{HHV} input as the minimum plant size. The implementation of this scale of hydrogen production units would require large amounts of biomass to be collected and transported with the corresponding associated costs. The collection of 1 million tonnes per year of biomass would require e.g. 0.5 million hectares of wheat crops to collect the straw, 1.5 million hectares of European forest if forest residues are considered, or 3 million inhabitants if MSW were the feedstock. Indeed there are several sources of potential biomass that can be used for hydrogen production. The next section analyses such value chains in more detail.

Figure 7: Iterative nature of analysing biomass-to-hydrogen chain with key criteria for steps.



1.5. Challenges: Choosing the value chain

In addition to the potential route to hydrogen which is our prime focus, a range of value chains exist for converting biomass to useful energy. Only some of these are used industrially today. The specific chains often refer to specific types of biomass, as illustrated in **Table 3** below.

Table 1. Routes for converting biomass into energy products and services

Biomass Resources	Processes	Biofuels	Energy services
Agriculture and forestry residues	Densification Esterification	Wood pellets Briquettes Biodiesel	Heat Electricity Transport
Energy crops: biomass, sugar, oil	Combustion Gasification Pyrolysis Fermentation/Distillation	Char/charcoal Fuel gas Bio-oil Bioethanol	Heat Electricity Transport
Biomass processing wastes	Digestion Hydrolysis	Biogas Bioethanol Solvents	Transport
Municipal waste	Digestion Combustion Gasification	Refuse-derived fuel (RDF) Biogas	Heat Electricity

Source: IEA Bioenergy programme .

For biomass, the transition from combustion-based to gasification-based processing promises higher energy efficiency, additional clean energy supply options for power and transport fuel, improved competitiveness for key industries, and new opportunities for foresters and farmers.

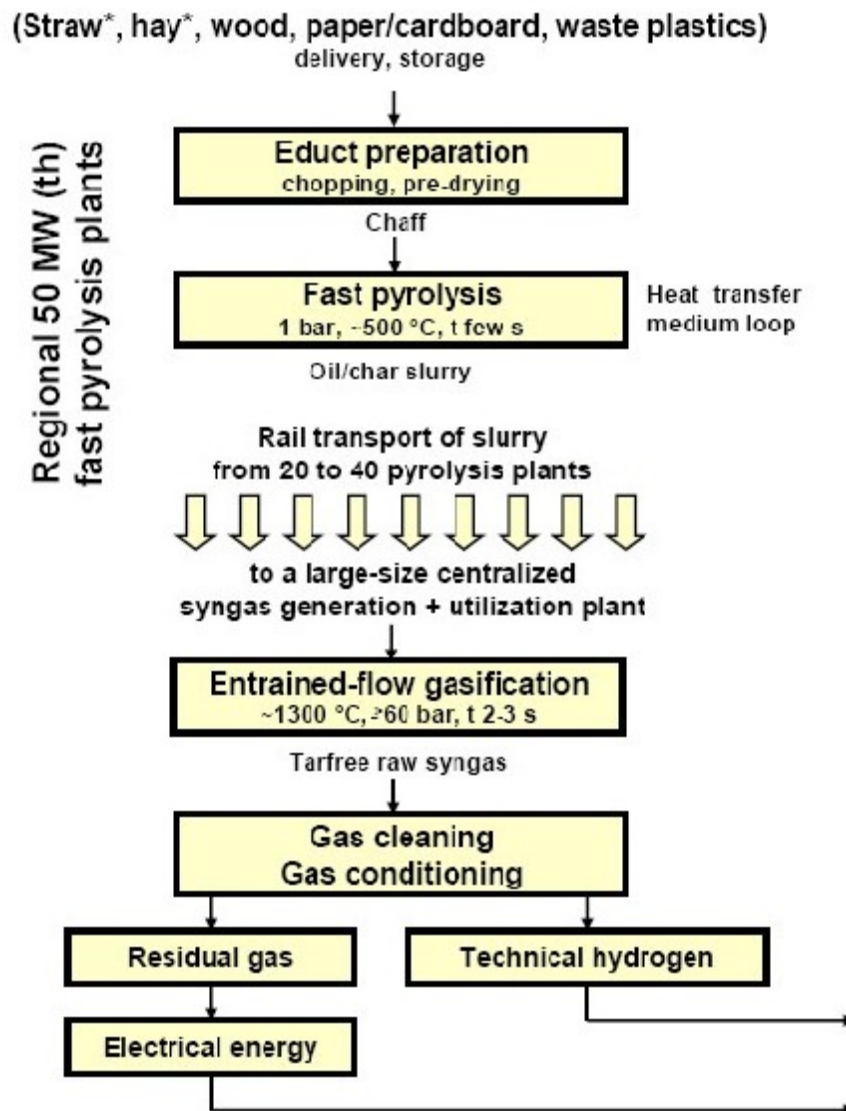
Unlike in power generation – where the goal is to maximise the calorific value – gasification for hydrogen production in principle aims at maximising the hydrogen yield. For practical reasons, however, it may be more appropriate to target maximisation of synthesis gas (carbon monoxide and hydrogen) yield which is the product of gasification and further processing of carbonaceous fuels. The higher oxygen content of biomass results in a lower hydrogen yield from the primary processing step, compared to the processing of natural gas by steam reforming, or of coal by gasification. However, after gasification, the obtained CO is reacted with further steam to yield additional hydrogen and carbon dioxide, in the water-gas shift (WGS) reaction. Altogether, the higher the oxygen (and carbon) content of the fuel relative to hydrogen content, a larger part of the hydrogen in the syngas originates from steam, obtained by the secondary WGS reaction.

Many vegetation-based biomasses can be compressed to pellets and briquettes providing more stable fuel quality and higher energy density. Today, for energy, these forms are used mostly with wood and forestry by-products, as well as with some types of (non-biomass) waste. Other ways of “densification” suitable also for non-woody biomass include *torrefaction* (“roasting”, for which moderate amounts of heat are required; e.g. low temperature industrial waste heat), and processing via flash *pyrolysis*. The use of such “split” or bi-modal value chains is of particular interest for biomass to hydrogen, because of its need for economics of scale.

Bi-modal value chains: Pre-processing

While both pyrolysis and gasification are ancient technologies, *Noell-DBI*^{*} process first demonstrated at Freiberg in the former GDR was apparently the first successful attempt to combine the pre-processing of a primary resource by flash pyrolysis, followed by entrained flow gasification to hydrogen or other synthesis gas products. This process was proven on industrial waste by pilot demonstration in the mid 1990's. Feeding the pyrolysis product to the 5 MW_{th} on-site pilot scale entrained flow gasifier²⁶. A simplified process scheme is shown in Figure 8.

Figure 8. Hydrogen from biomass via pyrolysis oil. *Source:* Future Energy.



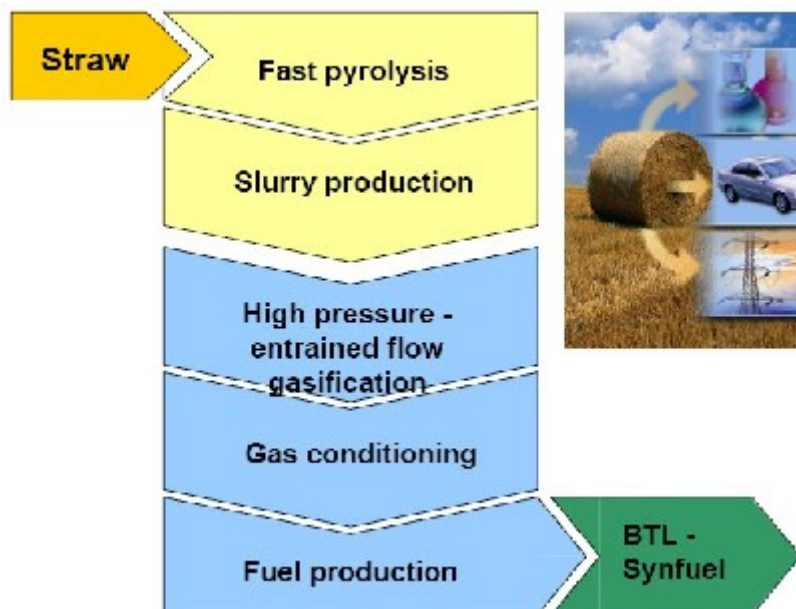
^{*} *Noell Abfalltechnik* of Hamburg, a waste management technology company, after the German reunification in 1989 took over the *Deutsches Brennstoffinstitut* (DBI; German Fuels Institute), the national fuels R&D center of the former GDR; both were subsequently brought into the Babcock Borsig group. From 2003, the Freiberg center with its related assets – notably the experimental gasification facilities at *Schwarze Pumpe* – have been controlled by Future Energy GmbH, a new company. Due to these rapid changes confusion abounds, especially in English-language literature, on the names as well as the content of the technologies concerned.

Because of its design, having been originally developed for saliferous lignites and lower-grade coals, the GSP (*Schwarze Pumpe*) entrained flow gasifier is particularly well suited to high ash and high chlorine feeds, especially if equipped with internal water cooled screens.

In the demonstration of the Noell DBI process, pyrolysis and gasification were carried out at the same place, without storing the intermediate “tar oil” (actually a slurry of char solids in pyrolysis oil). The concept of spatial-temporal splitting of the pre-processing of biomass from subsequent gasification of biomass has then been promoted by the FZK (Research Center Karlsruhe) as a new concept for making biofuels from biomass residues such as straw. See Figure 9.

Working together with Future Energy, FZK claims the process to have been verified by ongoing test campaigns and that it has provided syngas of adequate quality starting from a wide range of biomass pyrolytic intermediates. They are progressing towards planning dedicated biomass gasification plants for this use.

Figure 9. The so-called Karlsruhe BTL Concept ²⁷



Assessment of the “integral-split” value chain

Noting that the complex logistics of all value chains for biomass is a basic consequence of its dispersed nature, and runs contrary to the equally basic needs for economies of scale in any industrial scale production of fuels, Shell took this concept, which could be called “integral-split” processing, one step further ²⁸. Assessing the potential for a global approach with sea transport of pyrolysis intermediates a Dutch research team led by Shell have presented a value-chain modelling exercise to quantify the potential and costs, both of the above “indirect routes” and the “direct route” where biomass itself was transported without a pre-processing step. The actual biomass to syngas routes compared are shown in Table 4.

Table 4. Routes considered for the value-chain analysis of Calix et al.

“direct route”	“indirect route”
biomass harvesting	
biomass transport to biomass collection facility (“b.c.f.”)	
<i>system boundary</i>	
biomass storage & transshipment at b.c.f.	
	biomass pretreatment (chipping, drying)
	flash pyrolysis of biomass
	pyrolysis oil storage & transshipment at b.c.f.
biomass transport to exporting harbor (“hub”)	pyrolysis oil transport to exporting harbor (“hub”)
biomass storage & transshipment at hub	pyrolysis oil storage & transshipment at hub
biomass shipping to importing harbor	pyrolysis oil shipping to importing harbor
biomass storage & transshipment at syngas plant	pyrolysis oil storage & transshipment at syngas plant
biomass preparation (chipping, drying, pulverizing ²⁹)	
biomass gasification	pyrolysis oil gasification
syngas cleaning	
syngas compression	
water-gas-shift	
CO ₂ removal	
<i>system boundary</i>	
syngas conversion	

The *scale* used for this particular exercise is interesting: The case studied was a large 8 GW_{th} syngas facility, the size of a big refinery.

Using wood (can be seen a proxy for all biomass) it was unsurprisingly found that large wood volumes would be needed. They calculated the total forest area from which the biomass were to be collected to between 18,000 and 115,000 km². (The actual area would be even bigger if forest density is less than 100%, which is usually the case; in the Baltic countries it is estimated at some 40%. Notice that the upper bound in this figure is of the same order of magnitude as all the woodland in Europe²⁹. On the other hand, the volumes of biomass to be transported in the studied project (17 to 23 million tonnes oven dry material per year) are not exceptionally large, compared to for example coal movements between coal production and consumption sites. However, because of the distributed collection of biomass, logistics costs form a much more significant factor in biomass value chains than in those usually handled by the energy industry.

Using a critical path analysis to quantify also the sensitivities of both value chains, Shell’s study assessed technical and other risks and costs for the two routes and main processing options. It was concluded that the technical risks associated with entrained-flow gasification of pyrolysis oil in the indirect route, or of solid (dried & pulverized) biomass in the direct route, were much smaller than those for development and demonstration of pressurized, oxygen-blown fluidised bed gasification of biomass on the scale studied (gigawatts).

For the direct route via fluidised bed gasification, the major R&D risks were identified as fouling of the thermal tar cracker and the syngas cooler. For the direct route via EF gasification, the biggest technical risks are slagging in the gasifier and deposition of solids in the syngas cooler. For the indirect route, the main critical issue was found to be the reliability of the pyrolysis unit.

The manufacturing costs were also calculated for syngas, *i.e.* without either the deep water gas shift reactors for pure hydrogen or Fischer-Tropsch synthesis for the case of liquid biofuels. It was concluded that this cost can be as low as 6 €/GJ and as high as 13 €/GJ, depending on the biomass price (assumed to range from 0.6 to 4.0 €/GJ at the biomass production location, and the selected manufacturing concept (direct versus indirect). On the basis of the parameters used in the cost model, the relatively lower logistics costs associated with the indirect route are offset by significantly higher feedstock costs (due to a lower overall thermal efficiency) and the higher capital costs for two thermal conversion steps, one of which is carried out on a relatively small scale (240 tonnes per day). In the direct routes, uncertainty in the variable transportation costs (€/ton/km) per ship was found to have a strong effect on the uncertainty of the overall manufacturing costs. Importantly, the indirect route not only the cost was lower, but also the sensitivity was less; uncertainties in the capital cost and thermal efficiency of the pyrolysis unit are more important. The author suggests that a targeted technology development of biomass pyrolysis is an effective way of reducing uncertainties in the biosyngas manufacturing costs via this route.

In view of the major thresholds involved in deciding on any dedicated biomass technology plant with its associated feed logistics – especially on the scale in the study led by Shell! – it appears that a more pragmatic approach than a dedicated facility would be to keep the principle of pre-processing, and global trading of the intermediate, but instead assume using – a few percent, say 5-10-20 % co-gasification – of biomass in existing coal or residue gasification plants. These have a combined capacity steadily growing. Not only would such a “doubly dispersed” solution allow shorter transport (for both the direct and indirect routes in the sense of the Shell study), it could also allow better geographical spread of the finished product, *i.e.* less subsequent cost of fuel distribution (something of very high significance for hydrogen). An additional advantage is more flexibility in selecting the biomass feedstock vs. point of gasification. The major element to work on in any case is to lower and disperse the total risk: technological and financial.

Therefore, following essentially the same logic as the Shell-led study, to efficiently supply large biomass to hydrogen production, two value chains could be considered, both initially based on residues but with a very high upside potential relying on energy plantations:

- Centralised production units directly supplied with raw biomass;
- Semi-decentralised production, with the pre-conditioning of biomass into liquids by means of flash pyrolysis units located in biomass rich places, then transport of the energy concentrated intermediate to a “virtual biomass gasification plant” consisting of a multitude of already existing facilities, each co-gasifying at a moderate ratio biomass together with fossil fuels.

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Section II – TECHNOLOGIES

II.1. Processing biomass feedstocks

Biomass resources include a variety of natural and derived materials, as introduced in Sec. I.3. However with regard to their technological processing into useful energy, a further specification and classification is required such as one in accordance with the list below.

- Solid, untreated biomass
 - biomass as by-product or waste: from forestry (wood, bark, wood chips, stub ends), from wood processing industry (wood chips, sawdust, wood powder), from agricultural industry (straw, bagasse), from food processing industry, and from municipal waste
 - biomass as dedicated product: energy wood: sallow (*salix spp.*), energy grass (elephant grass (*mischantus*), alfalfa, sorghum, hemp; aquatic plants & algae
- Solid, upgraded biomass
 - wood chips, briquettes, pellets
 - powder
 - char from pyrolysis processes
- Liquid biomasses
 - vegetable oils (rapeseed, brassica, linseed, soybean, corn oil, sunflower oil), organic waste oils (deep frying fat, food waste, fish oil, offal, tall oil)
 - bio-diesel prepared by esterification of fatty oils (for instance from rape seed)
 - other processes based on vegetable oils
 - pyrolysis “oils” (a separate category, being both immiscible with oils such as those listed above and not completely water miscible.)
 - bio-ethanol from fermentation of chemical pulp (celluloses), sugar, potatoes, bone flour, corn...
- Gaseous biomass
 - biogas (methane), directly from waste disposal land fills, or from specialised digestion tank processes based on anaerobic digestion of manure, residues from plant sources, animal offal, sewage sludge and other wet organic waste
 - thermochemically produced gas (methane, hydrogen) by conversion of biomass, by means of pyrolysis or by means of gasification

Some of the materials above can be directly harvested as biomass resources (energy wood, energy grass, aquatic plants...), some become biomass resources from wastes (residues from forestry, wood processing, agricultural and food processing industry, municipal waste...), while others are upgraded products from other biomass resources (briquettes and pellets, bio-oils, biodiesel, bio-ethanol, biogas...).

In theory, all of the listed biomass resources could be considered for production of hydrogen. The availability and abundance of most biomass resource varies for the different regions of the world, as well as within the regions on a more local level.

Biomass pretreatment/upgrading

Typical major drawbacks of raw biomass' physical characteristics compared to fossil fuels are:

- raw biomass has low energy density
- raw biomass can't be crushed like coal
- raw biomass can't be pumped like oil

An important motivation for upgrading biomass is the possibility of using existing infrastructure.

The most important biomass upgrading technologies are:

- Carbonisation or torrefaction (drying) that produces a coal-like material, making milling to small sizes easier and comparable to coal milling
- Flash pyrolysis that produces a liquid material (pyrolysis "oil" or "bio-oil"); this is a liquid intermediate product that can easily be pressurised and intended to be nearly free of inorganic material (ash)
- Biological methanol and/or ethanol production from biomass that could be used to facilitate decentralised H₂ production

The obvious drawback of biomass upgrading processes is the extra work that has to be done, which, in addition to complicating the overall process, reduces the total value chain efficiency.

The choice of biomass resources to be used in a certain H₂ production process will depend on chemical and physical properties of the resource, as well as economics related to purchase and transport of the biomass from source to processing plant.

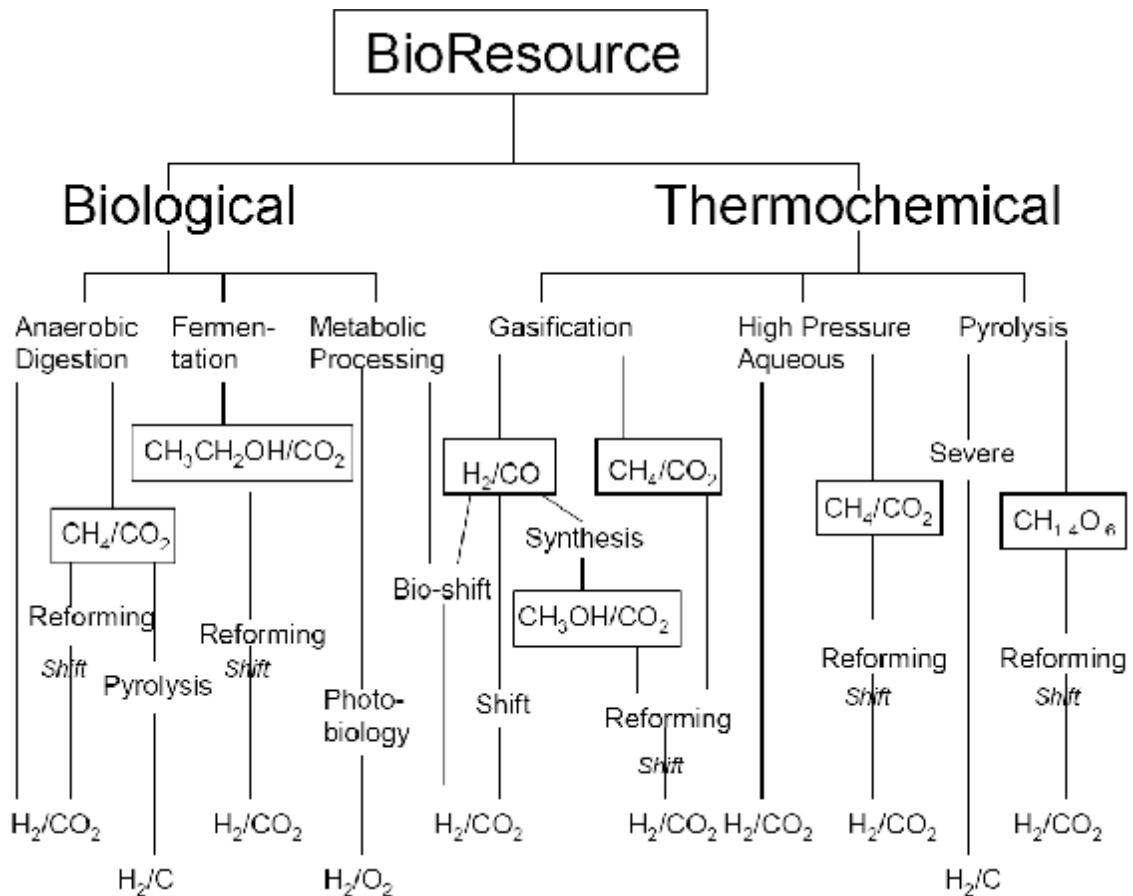
- Important chemical and physical *parameters* are size, homogeneity, moisture content, energy content (heating value), and ash content and characteristics (melting point...)
- Important factors to assess when considering process *economics* are local availability (distribution), supply stability, purchasing costs (depending on the type and quality of biomass – including costs for growing and harvesting), and transportation costs (depending on distance, density of biomass)

II.2. Technology options

Processes for conversion of biomass to hydrogen can be divided into two main categories, divided into subcategories as shown in the following list and figure:

- Thermochemical H₂ production processes
 - pyrolysis
 - gasification
 - high pressure (supercritical) aqueous conversion
- Biological H₂ production processes
 - anaerobic digestion
 - fermentation
 - photobiological

Figure 10. Pathways from biomass to hydrogen (H₂) – excerpted from Milne et al., 2002³⁰
Boxes indicate storable intermediates.



As can be seen from Figure 10, each of these processes can be capable of producing storable intermediates. Direct production routes are less complex, but the routes via intermediates have the advantage of giving an opportunity of distributed production of a more easily transportable product, hence making it possible to reduce logistics costs.

Pyrolysis as a process converts carbon-containing fuel such as biomass endothermically in an oxygen-free atmosphere to solids (char), liquids and gases. Slow pyrolysis yields mainly char and gas but fast – or “flash” pyrolysis can yield up to 70-75% liquid referred to as pyrolysis oil^{*}, along with char and gas. This chemically complex liquid can be a stable, storable intermediate product, which has been much investigated for further processed by various processes to yield methanol, transport fuels or stationary utility fuels, chemicals and materials, and H₂ by catalytic steam reforming and water-gas shift reaction (for instance after transportation from distributed pyrolysis plants to larger, central steam-reforming plants).

Gasification is a process that in general converts solid carbonaceous material (e.g. untreated or upgraded biomass) thermochemically by vaporising volatile compounds in the feedstock, while the resultant “char” is gasified by oxygen, steam and hydrogen. This yields a synthesis gas (or syngas) mainly consisting of H₂, CO and CH₄. Syngas can be converted to H₂ and CO₂ usually by the water-gas shift reaction ($\text{CO} + \text{H}_2\text{O} = \text{H}_2 + \text{CO}_2$), often by using catalysts. Synthesis gas can also be used for other purposes than producing H₂, for instance production of methanol. Gasification is considered as the most promising route for conversion of biomass to H₂.

High-pressure aqueous conversion of wet feedstocks is a conversion technique that utilises the advantageous characteristics of supercritical water, i.e. steam above its critical pressure point, such as its increased ability to dissolve and break down solid biomass.

Anaerobic digestion is a biological conversion process converting biomass to methane that can be converted to H₂ by conventional processes such as steam reforming; also possibilities for a direct bacterial assisted conversion to hydrogen are the subject of research.

Fermentation of biomass yields ethanol that can act as intermediates for further processing to H₂, having the advantage of being a less toxic intermediate than methanol. Steam reforming of ethanol to H₂ is, as for methanol, easier to perform than steam reforming of methane.

Photobiological processes are based on using organisms that produce H₂ in photo- (sunlight-) induced photosynthesis.

Variations of all processes occur, and for simplicity, only main lines are drawn in this overview. Parameters of interest for many processes are temperature, pressure, type of catalyst, steam/biomass ratios, type of reactor, type of biomass raw material, pretreatment methods, hydrogen purification/separation processes, heat sources, valuable byproducts, etc. Milne et al.³⁰ give a brief but extensive review of processes, related parameters and relevant literature.

Reported yields of the processes vary a lot depending on type of biomass resource, type and variant of process, as well as choices for the different parameters influencing the yield. Yield strongly depends on energy input, process and logistic efforts, adding to the total production costs per amount of H₂ produced.

Economics of many processes can be greatly enhanced by making valuable by-products.

^{*} The terms “bio-oil” or even “bio-crude” are commonly used; however such liquids only superficially resemble *oils* – not being miscible with oils or fats – and shares with *crude oil* only the fact of being a complex and unrefined mixture. Pyrolysis oil is a water suspension or multiple micro-emulsion with a high content of oxygenated organic compounds. Chemical characterisations of various types of pyrolysis oils are available, for example via www.pyne.co.uk

Technology for “Second generation” liquid biofuels

Interest in synthetic liquid fuel processes tends to re-appear periodically at times when world oil prices are very high and there is currently a lot of interest and some novel development in the so-called “second generation” liquid biofuels, also referred to as “cellulosic” biofuels. In fact, the majority of technologies involved are old and well known with full experience at industrial scale.

Producing bioethanol from cellulose can deliver a petrol (gasoline) substitute, which is identical to the bioethanol produced from sugar or cereals. Synthetic enzymes – the innovative step at the center of most development efforts – provide a key to unlock the cellulose molecules and break them down into simpler substances, which are then subsequently fermented to ethanol, and purified (distilled) the same way as conventional bioethanol. It is hoped that the resultant energy balances and, hence, CO₂ emission reductions will be largely enhanced. The world first demonstration plant was put in operation by Iogen in Canada (4 million litres per year). It was followed by ETEK in Sweden (150 000 litres per year pilot plant). Many further demonstration and soon-to-be commercial facilities are planned or in construction. Enzymatic hydrolysis is expected to become competitive in the medium term due to decreasing price of enzymes and low cost of the raw material (such as straw or even wood); being one of the most critical parameters in the overall cost of the biofuel.

In contrast to the case with ethanol, second-generation biodiesel is chemically different from vegetable oil based biodiesel and requires little or no technological innovation on the processing side. Gasification of biomass produces synthesis gas consisting mainly of hydrogen and carbon monoxide (CO).

Fischer-Tropsch technologies for producing synthetic liquid fuels from the gaseous feedstock resulting from gasification of carbonaceous solid fuels are proven and commercially available. Fischer-Tropsch synthesis formed a strategic element of Germany’s WW2 energy supply – an economy required by the war and blockades on trading to become as independent of imported hydrocarbon fuels as possible.

The production of F-T liquids in Germany and occupied Europe peaked in 1943 at 650,000 t/yr, supplying up to 10% of the war demand for military and strategic fuels. (In fact, the majority of Germany’s fuel demand was satisfied by direct coal liquefaction using the Bergius process).

After WW 2, Fischer-Tropsch technology was prohibited in Allied occupied Germany, and after a few years was displaced by the availability of cheap hydrocarbon fuels elsewhere except as maintained by political priorities. Notably, the white regime in South Africa established from the 1950’s a comprehensive self-contained national fuel supply based on gasification of coal and Fischer-Tropsch, which over the 1960’s and 1970’s grew to more than 10 times the scale of the German wartime production. Still today’s South Africa, with an economy ranked in size with that of the Netherlands (at PPP), and in rapid growth, produces 28% of its motor fuels (petrol and diesel) from Fischer-Tropsch synthesis, processing 45 million ton/year of domestic coal*.

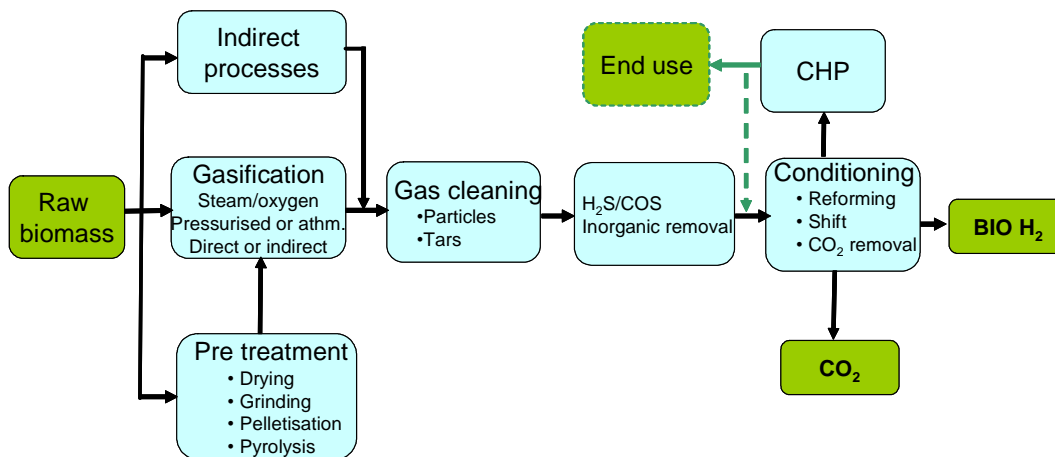
* As a comparison, China uses only for its H₂ production about 50 million t/yr of coal as gasification feedstock; note that China’s H₂ production officially is the world’s 2nd largest, growing and perhaps already exceeds that of the US.

II.3. Technology scales and logistics

From end use to feedstock requirements

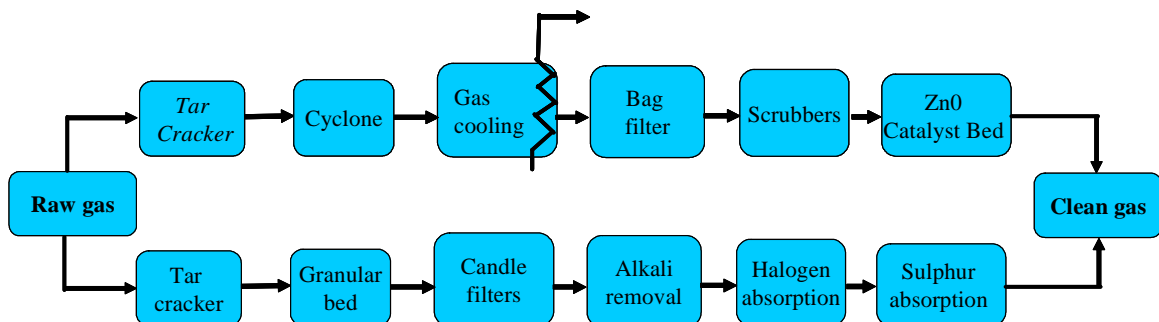
As introduced in Section I.2, the importance of carefully assessing biomass feedstock issues in terms of technologies as well as markets/value chains cannot be overestimated. Estimates of potential biomass use and corresponding potential for “renewable” hydrogen production should take into account the potentials corresponding to the surfaces appropriate for energy crops to produce biofuels. Any estimate of hydrogen potentials will also depend on technical choices for the preparation of the biomass. Since the most obvious and direct route of hydrogen production from biomass is the thermochemical route via gasification, the present chapter will focus on this pathway. Figure 11 below recalls the main steps of the process.

Figure 11. Biomass to hydrogen through gasification pathway.



In particular, the gas cleaning required for gases resulting for typical biomass gasification conditions (see Figure 12 below) represents a complex and long succession of processes which most generally cannot be applied on small scale, or which at least would require savings from economy of scale.

Figure 12: Biomass gasification gas treatment.



Even if the reforming and water/gas shift units can be applied on small scale, the removal of inorganics and desulphurisation plant still require large units to be economic, taking into account the very strict requirements of the shift catalysts towards sulphur content in the gas. As with H₂ produced from coal or residues, but in contrast to the production from natural gas, over half of the hydrogen produced from biomass comes from the added steam in the shift reaction (-s), the total volume of gases produced has a high CO₂ content that could present a food case for CO₂ capture – resulting, for biomass, in negative emissions.

All these aspects of the process imply a need for large scale units in order to allow “renewable” hydrogen from biomass to compete with “conventional” hydrogen production routes like steam reforming of natural gas, or from coal and oil residues via industrial gasification. Helping to offset this cost handicap will be the status of hydrogen from biomass as a renewable resource^{*}, at least under appropriate market conditions where CO₂ emissions have an associated cost. be the status of, *i.e.* with To illustrate the cost competition, Table 5 below shows current estimate of the cost structure and cost breakdown for these established production routes as currently available as well as their CO₂ emissions.

Table 5. Hydrogen cost estimates and CO₂ emissions for current production routes.

Hydrogen from...	H ₂ production cost		Cost distribution %			CO ₂ emissions
	\$/GJ	€/ton	Feed-stock	Invest-ment	O&M	ton/ton H ₂ produced
Natural gas	5 – 7	750 -1050	42-61	20-41	10-17	10
Petroleum (residues)	8 – 12	1200 – 1800	28-35	50-52	10-17	12 – 15
Coal	9 – 15	1350 – 2250	16-21	55-59	20-25	16 – 19

Source: Loubette, 2005. Note: This may be based on natural gas prices lower than those in the markets today.

Clearly, CO₂ emission pricing starting from as little as 10 € per ton CO₂ would have a significant impact on pricing, improving the competitive situation of hydrogen from biomass.

For a more long term view of price competition, it is necessary to include both the variability in feedstock prices and the likely use of CO₂ capture & storage (CCS) in fossil based processes. Here, a good choice can be found in the recent IEA scenario calculations for hydrogen and its competing solutions until the year 2050¹. **Table 6** shows a summary of costs used. Note that

- these are for large volumes (bulk industrial quantities of hydrogen),
- the electrolysis based routes are based on a 2020-30 time frame
- the costs referred are technical cost, *i.e.* no “risk premium” is included for hydrogen

^{*} CO₂ emissions from hydrogen produced from biomass will be limited to those resulting from the use of fossil fuels or other emission sources during biomass growth (including fertilisers produced using fossil fuels), collection, production and distribution. Such data for hydrogen from biomass are not known to us, but various estimates for other bioenergy applications usually arrive at a fraction of 10 to 20% of the GHG emissions of comparable fossil fuels. In other terms, biomass energy under typical conditions of use may be seen as, say on average, “85% renewable”.

Table 6. Hydrogen costs used in long-term scenario modelling. *Source:* D. Gielen et al. (IEA, Paris)

	Feedstock price	Feedstock cost [\$/GJ H ₂]	Other prod. cost [\$/GJ H ₂]	Transport cost [\$/GJ H ₂]	Refueling cost [\$/GJ H ₂]	Total cost at fuel pump [\$/GJ H ₂]
H ₂ from natural gas w/ CCS	3 - 5 \$/GJ	3.8 - 6.3	1.2 - 2.7	2	5 - 7	12 - 18
H ₂ from coal with CCS	1 - 2 \$/GJ	1.3 - 2.7	4.7 - 6.3	2	5 - 7	13 - 18
H ₂ from biomass (gasification)	2 - 5 \$/GJ	2.9 - 7.1	5 - 6	2 - 5	5 - 7	14 - 25
H ₂ from onshore wind	3 - 4 cents/kWh	9.8 - 13.1	5	2 - 5	5 - 7	22 - 30
H ₂ from offshore wind	4 - 5.5 cents/kWh	13.1 - 18.0	5	2 - 5	5 - 7	27 - 37
H ₂ from thermal solar elec	6 - 8 cents/kWh	19.6 - 26.1	5	2 - 5	5 - 7	32 - 42
H ₂ from solar PV	12 - 20 cents/kWh	39.2 - 65.4	5	2 - 5	5 - 7	52 - 82
H ₂ from nuclear	2.5 - 3.5 cents/kWh	8.2 - 11.4	5	2	5 - 7	20 - 27
H ₂ from HTGR cogen. heat	NA	NA	8 - 23	2	5 - 7	15 - 32

PV = PhotoVoltaics. HTGR = High Temperature Gas-cooled Reactor. NA = Not Applicable

This table lists the total costs of hydrogen for vehicle re-fuelling *i.e.* including H₂ distribution and filling stations, production cost being the sum of the two first cost columns. Interestingly, we see here that hydrogen from biomass via gasification is expected in this time frame to become quite competitive with the fossil routes including CO₂ capture & storage, and the lowest cost of all the renewable routes. Assuming substantially higher costs for natural gas feedstock, as is the case today, the long-term cost comparison would be even more favourable for biomass.

Technical choices and biomass availability: Agricultural residues

Residues being in many case a cheap source of bio-energy they can be used for energy in the short to medium term. However, the expected increase of biomass demand and GHG emission reduction may limit agri-based residues availability as it might be preferable to increase the soil organic matter content by leaving some. The main issues to tackle when considering the use of residues for modern energy are:

- Methodology and assumptions for determining what is and what is not a recoverable residue. Estimates often vary by a factor of 5, due to variations in the percentages of residues assumed available given requirements for soil organic matter and soil erosion control, efficiency in harvesting, losses, non-energy uses, animal manure production...
- Other alternative uses of the biomass: animal feed, paper, fertilisers. Straw and other agri-based residues usually have a very low moisture content (10%), which is a clear advantage to compare with woody biomass; however, it has a higher ash content that results in a lower calorific value and constitutes a source of contaminant for several biofuel technology alternatives. To improve its bulk density, the straw is generally baled before transportation. These technologies are well established and methods exist for very high density baling. Some attempts were done (particularly in Denmark) to reduce the ash content of the straw by washing it at a mild temperature (60°C). The washing allows reducing significantly the alkali content of the straw. However, washing does not remove all ashes and it increases the moisture content. Further drying may therefore be necessary afterwards particularly for gasification.

Straw is already used on large scale for energy generation (Denmark) or in the paper industries (China). Due to the ban of field burning and the development of more livestock practices, straw is largely available in industrialised countries. However, in tropical countries, alternative uses and the weakness of infrastructure for transport could limit their availability. The same remark applies for cotton stalks, corn cobs and other herbaceous feedstock.

Wheat straw constitutes the largest single crop residues worldwide. However, as seen above in most temperate climates there is an established set of offtake channels. To better illustrate the hydrogen from biomass potential specifically for some regions in which fuel demand is rising – cf. the discussion in Section I.4 – and which thus are candidates for biomass-to-hydrogen, it is useful to look at some tropical crops instead.

Cirad and BTG ³¹ realised a survey on the potential availability of first- and second-generation agri-based residues from tropical crops and ranked the largest countries by volume.

The results are given in Table 7. It was found, for example that more than 300 Mt (million tons) of bagasse from sugar crops are produced worldwide, today mostly used as fuel in sugar cane factories, often burned at low efficiency with high noxious pollutant emissions. Rice husk and straw are by far the largest potential with a volume larger than 600 Mt/yr.

Table 7. Agri-based residue potential from tropical crops in the 13 largest world producers (tropical and partly tropical countries) in *Mt dry matter* ³²

	Bagasse	Rice straw	Rice husk	Cotton stalks	Sorghum straw	Coconuts-husk,shell	Total Mt dry matter
China	10.6	209.3	36.9	35.1	3.8	0.1	295.8
India	40.4	143.6	25.2	12.9	9.8	4.1	236.0
Indonesia	3.2	57.5	10.1	0.1		6.8	77.6
Brazil	44.4	12.2	2.2	5.2	0.9	0.9	65.7
Viet Nam	2.3	36.8	6.5	0.1		0.4	46.0
Thailand	8.0	28.9	5.0	0.1	0.2	0.6	42.8
Pakistan	6.3	7.7	1.4	13.8	0.3		29.4
Philippines	3.3	14.2	2.5			5.7	25.7
Mexico	6.0	0.3	0.1	0.6	7.4	0.5	14.9
Australia	5.2	1.5	0.3	4.0	2.5		13.5
Nigeria				1.0	9.5	0.1	10.6
Colombia	4.4	2.6	0.5		0.3		7.7
Cuba	4.9						4.9
Total 10⁶t	138.6	514.5	90.5	72.9	34.7	19.3	870.5
Total PJ	1123	5145	1131	729	347	386	8861
energy content GJ per tonne	8.1	10	12.5	10	10	20	

Rice straw accounts for 56% of the top ten global crop residues, followed by bagasse (15%) and rice husk and cotton stalks (10% each). China and India present by far the largest agri-based residues potential in the world because of their share primarily of rice by-products: straw and husk, which represent 83 and 71% of their respective potentials.

Taking, as an example, *only* the rice residues in the seven South & East Asian countries in the table, and comparing to the scale of their transport fuel market (Table 3, Sec. I.4.) the potential for transport-fuel substitution is evident. We now see – using not some speculative number for the world potential, but residues *from their own rice crops alone* – that a biomass resource with an energy content of more than 6 EJ is available, equivalent to nearly 150 million tonnes of oil. Assuming a biomass-to-hydrogen conversion efficiency of 55%, almost 20% of the anticipated fuel demand in these seven emerging major fuel-consuming countries could be supplied from their own rice residues if they switched their mass motorisation to hydrogen-fuelled vehicles*.

Of course, real biomass availability must face ecological constraints. And most of the countries with the highest agri-based residues potentials are high-growth economies, facing considerable increases of other energy demand, particularly electricity. The present annual increase in electric production capacity varying from 3% per year in Brazil to more than 14% in Vietnam. With such demand, and limited investment capacity of their utilities, independent power production (IPP) schemes are promoted in many countries. Agro-industries themselves have large heat and electricity needs which could favour investing in cogeneration schemes. For these reasons, it is difficult to consider these biomasses exclusively for large scale hydrogen or biofuel production, except in specific regions *e.g.* where a poor electricity grid limits the sale of power, or in a transitory phase. Nevertheless, the fact that transport depends nearly 100% on oil as a source is a strong argument in favour of prioritising biomass for transport application.

As already introduced, another option is to base hydrogen production also on woody biomass, especially short-rotation forestry and dedicated energy crops. This is discussed in the next part.

Technical choices and biomass availability: Wood and dedicated plantations

Conventional forestry systems³³ yield biomass for energy mostly as a by-product of timber production practices. However, in certain circumstances, they can also produce biomass for energy as a primary product. The normal life cycle of forests in conventional forestry systems includes reforestation or regeneration, a sapling stage of rapid height growth, an intermediate stage of steady growth in diameter/height/volume, finally reaching maturity/harvest after 30-80 years. Any harvesting operation, whether thinning in young stands, or cutting in older stands for timber or pulpwood, can yield tops and branches usable for bioenergy. Also, stands damaged by insects, disease or fire can be sources of biomass for energy purposes.

Forest residues typically constitute 25-45% of the harvested wood, so implementing biomass production may be a significant part of forest management decisions. Cost-effective handling of biomass requires careful harvesting, handling and transport suitable for different conditions and scales of operation, and may have to be modified by integrating operations to enhance efficiency. There are ancillary benefits from intensive harvesting, such as improved access for site preparation and planting, and reduced risk of fire and damage from insects and disease.

In assessing the economic sustainability of biomass harvesting systems, all costs and benefits are important. Forest residues normally have low density and fuel values that keep transport costs per energy unit high, so it is most economic to increase the density close to source. This is done by comminution (reducing residues to small pieces with a chipper, grinder or a flail), or by compaction into bundles, termed *compact residue logs*, which can be handled efficiently.

* This number refers to 2010; demand growth as noted in Sec. I.4 will reduce the share – but *e.g.* the introduction of the more fuel efficient FC powered would offset the drop, as would an increase in other sustainable H₂ supply routes.

Energy plantations are grown and harvested to specifically provide energy. Production costs are still relatively high but may come down as plant varieties with higher yields are bred and efficient harvesting methods are developed. Energy plantations are already in development, namely in Brazil where eucalyptus plantations are supplying charcoal to the steel industry.

Productivity of any plantation varies according to many factors among which species and plant selection, plantation and maintenance techniques. In addition, the location accounts for a large part. When water is not the limiting factor, tropical countries benefit from favourable climatic conditions that allow productivity two to three times higher than northern countries like in EU.

If full tree utilisation maximises the short-term biomass yield, it also means a larger removal of nutrients from the soil. Forest growth and continuing high yields require leaving on the soil part of the nutrients. As with agri-based residues, if the nutrients balance is not carefully controlled, it can affect yields and biodiversity – maintaining the plantation's sustainability would require an increasing use of fertilisers. It is thus important to find an appropriate balance between high biomass production yields and the long-term fertility of forest soils. Achieving such a balance is relatively easy in practice, since the largest part of the carbon content of a tree is bound in the stems, while the majority of nutrients are contained in leaves and branches. Thus, after felling, the good practice would consist in leaving the full tree on the ground for a couple of weeks. During this period, allowing a significant drop in moisture, the leaves and small branches fall down and the nutrients are back to the soil ³⁴.

In Brazil ³⁵, significant gains in productivity were achieved with the adoption of more intensive forestry techniques (preparation of the soil, fertilization, breeding ...); from a productivity of 15 m³/ha/year in 1967 to 21 m³/ha/year today ³⁶. With introduction of new materials, and through clone selection, a 40 m³/ha/year was achieved ³⁷.

This very high productivity allows Brazilian steel industry to efficiently use wood as a feedstock, after its conversion to charcoal. Considering a 30 to 40 m³/ha/year production in a 6 year cycle, each hectare will have a wood production volume of 180 to 240 m³. On this basis, the average Brazilian production costs are within the following intervals in US dollar ³⁸:

- Implantation 337 US\$/ha = 1.4 - 1.8 US\$/m³ wood
- Maintenance 146 US\$/ha = 0.6 - 0.8 US\$/m³
- Budding 237 US\$/ha = 1.0 - 1.3 US\$/m³

The total overall plantation cost adds up to 3 - 4 US\$/m³ or 5 - 6.6 US\$/t, or **0.3 - 0.5 US\$/GJ**.

Growing **dedicated herbaceous crops** for energy purposes is also possible. However, information on various aspects of their cultivation is still limited despite intensive research, particularly in the USA and the EU. The main herbaceous species considered for energy application are miscanthus, switch grass or cane fibre. Miscanthus is an attractive option, since it requires low input while yields can reach up to 15 tons per hectare per year under optimum conditions. To compare with a short rotation forest plantation, herbaceous crops have lower moisture contents but are bulkier products, increasing transportation costs. Their ash content is higher with a wider composition, including some undesirable compounds which may deactivate or poison catalysts if they remain in a process stream, as well as create corrosion and slag problems with some type of process equipment (in particular, lower temperature gasifiers).

Energy crops can provide a useful energy source both for the export and local markets. Today, tropical countries like Malaysia or Thailand are looking into establishing dedicated plantations mostly for liquid biofuel production for the transport sector.

With a 400 MW_{HHV} biomass gasification plant for hydrogen production as introduced by Faaij and Hamelinck (Sec. I.4), such scenarios imply:

Directly supplied, raw biomass required would represent 1 Mt of wood. With an average plantation productivity of 15 t/ha/y (eucalyptus), this would mean 67,000 ha of plantations. For comparison purposes, in Brazil nowadays, large steel industries are generally managing 40,000 ha of eucalyptus plantation to produce the charcoal required. The biomass supply zone would then be within a radius of 20 km around the hydrogen plant if plantations cover 50% of the area, or 46 km radius the plant if plantations cover 10% of the area. While quite unremarkable in Brazil, such surfaces may not be easily available in many parts of the world. Hence the number of unit feasible world-wide would remain limited, or those regions possessing them would be oriented towards export (*cf.* the Shell modelling study referred to in Sec. I.5).

In the case of multiple decentralised processing, 45 flash pyrolysis units with a 100 t/d capacity and 70% efficiency would be required to handle the considered 1 Mt of biomass. The biomass supply zone for each pyrolysis unit would then be 2,000 hectares and produce 30,000 tons of wood yearly. Such area is equivalent to that of a large farm, as is relatively common worldwide. Up to now, research in flash pyrolysis has been mostly devoted to oil quality for the substitution to fossil fuels after hydro-cracking, which limits efficiency due to very strict quality requirements.

If hydrogen would create good prospects within a wider spectrum for pyrolysis oil quality, larger flash pyrolysis units could be foreseen, handling *e.g.* 1000 t/d of wood and obtaining a higher yield (80%). Such up-scaling of pyrolysis plant would allow some 4 pyrolysis units to supply the 400 MW_{HHV} plant with pyrolysate for processing. Refer also to the scales illustrated in Fig. 6.

This latter “semi decentralised” option enlarges the possibilities as it reduces land availability constraints. Pyrolysis units could indeed be located in remote areas were biomass for energy can be grown without competition, the pyrolysate being transportable over large distances with moderate cost impact. River and sea transport can be considered³⁹. The number of potential plant implementations would be larger, their circumstances of implementation more diverse, and the scale of the centralised hydrogen production unit could be optimised and even can be supply with a wider spectrum of primary feedstock as the pyrolysis step have homogenised them through a liquid.

II.4. Gasification: industrial state-of-the-art

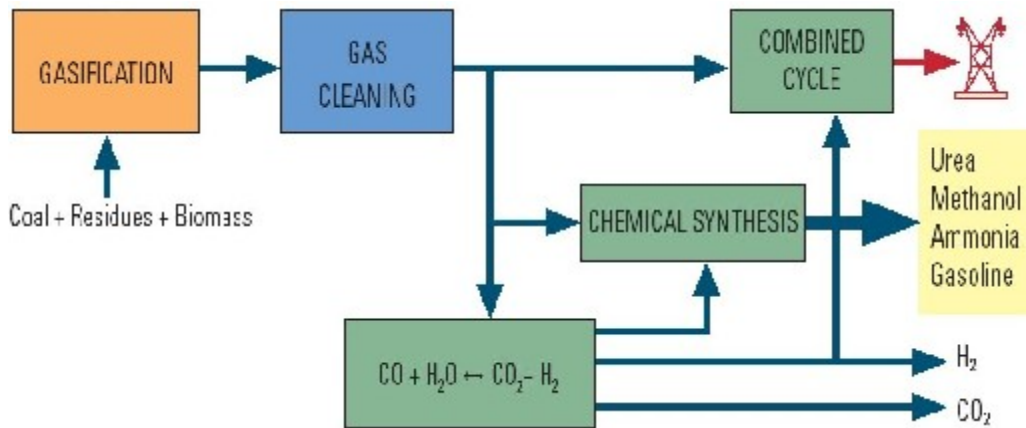
Introduction and process characteristics

Gasification is the industrial non-catalytic conversion of carbon-containing fuel into a gaseous mixture, which is then further processed to useful products such as fuel gas, heat, electricity or chemicals. Gasification fuels are typically solids, such as coal, biomass or wastes; but can also be liquids – typically those too viscous or otherwise difficult to process by other technologies.

Historically, gasification was first used for wood in the late 17th century, and then with coal on a massive scale in all the industrial societies from the early 1800's, as the source of "town gas", for fuels and as the base of the world's organic chemicals industry. After 1945, gasification was displaced from most of its global industrial markets by the availability of cheap petroleum, while natural gas or LPG took the domestic markets for cooking gas in nearly all countries.

Modern gasification has seen a renaissance since the 1970's driven by higher costs of oil and gas and the emergence of integrated gasification combined cycle (IGCC) technology as a new, cleaner process for the generation of electricity from coal than conventional combustion plants. The general scheme of a modern gasification process is shown in the figure below.

Figure 13. Generalised state-of-the-art gasification process. (Source: Modified from Elcogas.)



Compared to the other thermo-chemical processes, gasification differs from *pyrolysis* by using externally supplied oxidant – air, O₂, steam – and from *combustion* by using a lower oxidant to fuel ratio. (Gasification is sometimes for this reason also referred to as *partial oxidation*.)

Gasification is conventionally classified by the type of reaction vessel (the gasifier) and oxidant. It is a fuel-flexible technology capable of handling a wide range of coals and wastes, as well as hard-to-process liquids. Gasification needs above 600 °C temperatures; typically 700 – 900 °C when using air, or 1000 – 1400 °C with oxygen. Gasification can be done at atmospheric conditions, but most industrial processes use pressures of typically 40 – 70 bar and using oxygen.

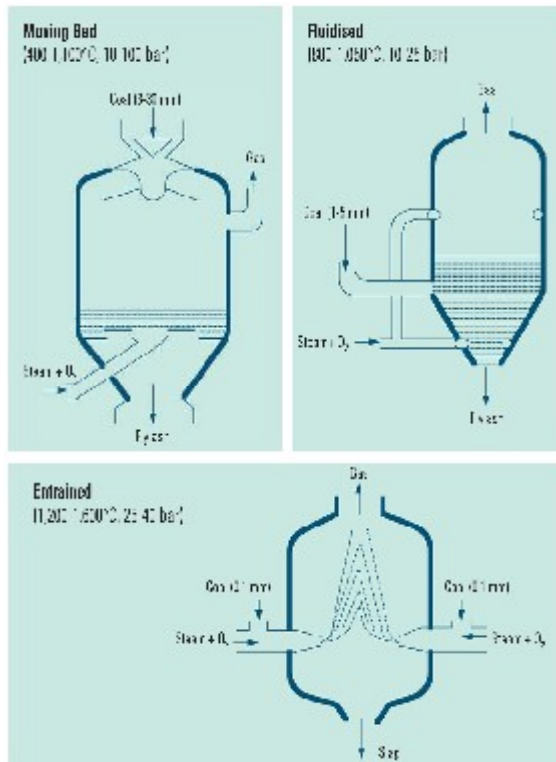


Figure 14 (left) shows the 3 main classes of gasifier used industrially today.

Moving-bed, or *Lurgi*-type gasifiers, used by Sasol plants in South Africa are a dry ash design, while the *British Gas Lurgi* is a slagging type, both installed in groups.

Fluidised beds are rare in modern plants, but the *high temperature Winkler* gasifier has been used with lignite on large scale; the *KRW (Kellogg)* is a bubbling fluidised bed design that can be air- or O_2 -blown.

Entrained flow gasifiers dominate today. Two types have most of the market: the “*Texaco*” gasifiers – now owned by GE – and “*Shell*” gasifiers, with two processes, SGP and SCGP. Other designs include “*E-Gas*” and the *Schwarze Pumpe (GSP)* entrained flow type, today Future Energy.

Table 8 below sums up key characteristics and optimal use of each of the three categories.

Gasifier type and their characteristics	Fuel and more suitable use
<p>Moving bed</p> <ul style="list-style-type: none"> • High residence time 15-60 min • Lump fuel, 5-30mm • High efficiency • Low gas T (400-500°C), producing hydrocarbons and tars • CH_4 high level content in synthesis gas 	<ul style="list-style-type: none"> • Flexible, wide range of coals, except those with tendency to produce fines. • Suitable for hard pulverisable fuel: biomass, wastes. • Better for chemical synthesis applications, in which produced hydrocarbons are useful. • Limited options for H_2 coproduction.
<p>Fluidised bed</p> <ul style="list-style-type: none"> • Temperature 800-1050°C. • Sieved fuel <5mm. • Low efficiency, air burned. • Medium residence time 10-100 s. 	
<p>Entrained flow</p> <ul style="list-style-type: none"> • Ash extracted as molten slag. • Pulverised fuel, <100 μm. • High gas temperature 1000-1600°C. • Short residence time 1-5 s • High efficiency • Neither tars nor hydrocarbons are produced 	

Key features of entrained flow gasification

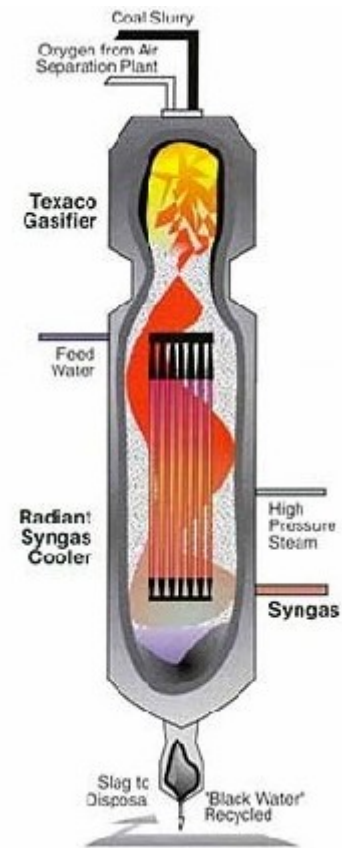
Entrained flow gasifiers differs from others in having no solid bed. Instead, fuel is *entrained*, or dragged along, with the gas stream*. Coal must be finely pulverised, and in the Shell SCGP, Prenflo and GSP gasifiers, it is fed pneumatically using inert gas; then injected together with oxygen in burner (-s). Here, vortex mixing occurs and local temperatures can reach more than 2500 °C. In the “Texaco” design coal is introduced as slurry in water, as are liquid or semi-liquid fuels in all types. **Fig. 15 (right): Texaco gasifier, principle.**

It is the high temperature in the resultant *dust flame* that causes entrained flow gasifiers to be principally tar-free. The absence of a bed makes for short residence times, and very short reaction times contribute to making entrained flow gasifiers fundamentally more easy to scale up than either fixed or fluidised bed solutions. They scale up to hundreds of MW_e. Tests have been done in some of the commercial gasifiers to co-gasify biomass with good results and the regular use of biomass in feeding ratios of order 10 - 20% is considered quite feasible, given adequate process optimisation for the respective feedstock properties.

Historically, entrained flow gasification comes from two roots, both starting in the 1950's: from partial oxidation of *refinery oil residues*, done industrially at pressure since the 1950s, the origin of both the Texaco and Shell SGP processes, and atmospheric gasification of *coal* by the Koppers-Totzek process. The latter was in the 1970's developed into a pressurised process at Freiberg in the former GDR, which was industrialised at *Schwarze Pumpe*⁴⁰; and by Uhde in West Germany who demonstrated a pilot plant at Shell's Hamburg-Harburg refinery in 1980 that became the basis for Shell's SCGP process (and for the similar *Prenflo* process).

The SCGP and related designs are side-fed with multiple burners placed radially, and syngas exiting from the gasifier's upper part. They use a water-cooled internal wall, not a direct quench as in the original Texaco process. (The Freiberg/GSP gasifier is top fed, and uses a removable internal cooling jacket.) These are *slagging* gasifiers: the high temperature creates molten slag, which flows down the wall – this helps to get higher carbon conversion, encapsulate e.g. heavy metals and protects the vessel wall better than only a refractory lining which can be sensitive to temperature variations⁴¹. Since the slagging parameters depend critically on the feedstock ash properties, optimising gasifier operation is an important task for processing any blended fuel.

The gasifier produces syngas, a mixture of CO and H₂ with small amounts of other compounds, mostly H₂O and CO₂. A train of processes to convert the syngas to required specifications then precedes the shift and separation reactor, and any downstream processing. Syngas undergoes a series of chemical reactions in this relatively conventional processing. To optimise hydrogen yield, it is reacted with more steam in a water/gas shift reactor, yielding more H₂ and CO. It can also be converted to many other final products including methanol, dimethyl ether and Fischer-Tropsch liquids (synthetic hydrocarbons) in addition to producing electricity in combined cycle.



* Entrainment is a well-defined term in fluid dynamics, nevertheless misunderstandings such as “entrained bed” occur in the literature. The original German name *Flugstromvergaser* – or, even more, the Dutch *stofwolkvergasser*, literally “cloud-of-dust gasifier” – are more immediately descriptive of the physical process occurring.

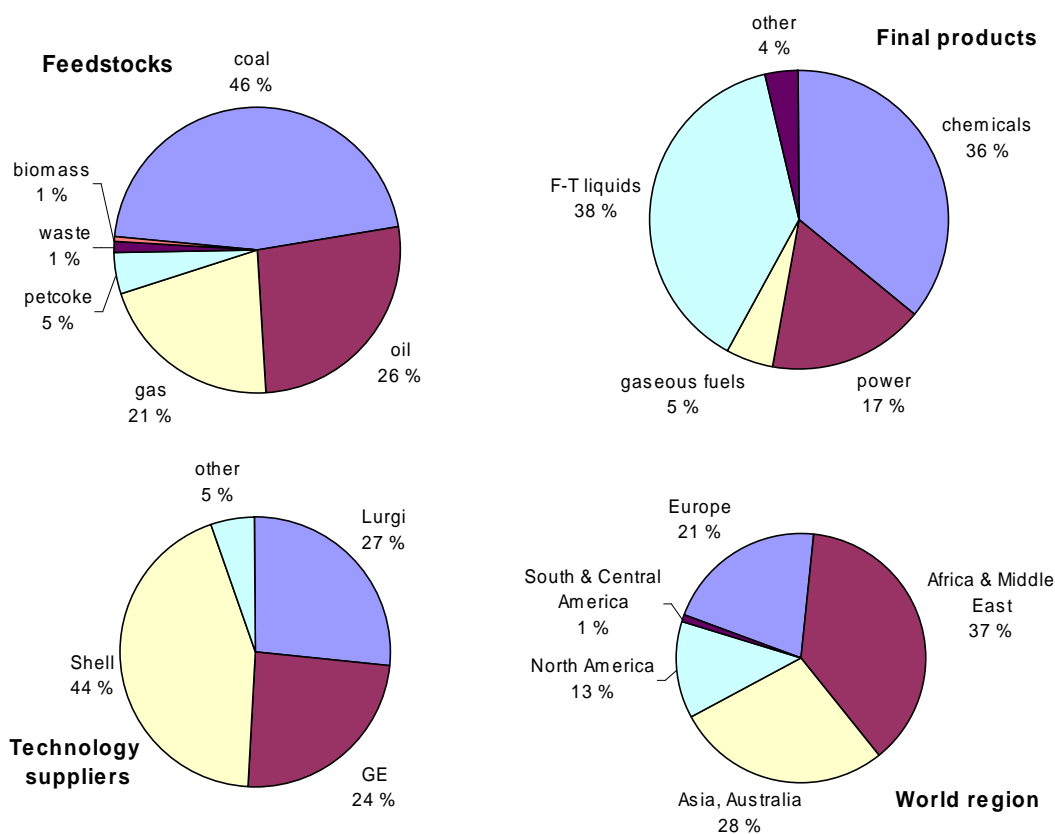
Industry status

Gasification is thus a proven technology for a wide range of commercially traded fuels, and also successful as a means of processing large volume industrial residues and waste materials in a clean way, with low pollutant emissions. In the commercial power generation market, IGCC is a new state-of-the-art technology struggling to win higher market share after a few years of being available, and with several suppliers. Adoption for power has been slow due to the higher initial cost of IGCC, which has dropped but still is 20% above conventional coal-fired plants. It seems justified to assume that the lower pollutant emissions, higher efficiency and – above all – much easier adaptability of IGCC to CO₂ capture, will change this drastically in the future.

Even so, gasification has become a significant and visible global industry with a healthy growth rate: Capacity is increasing from **45 GW** (thermal, calculated as syngas output) at end of 2004 to above **70 GW** in 2010 *, including the 38 new plants known to be under construction (66 new gasifiers). At the end of 2004, there were in operation 117 plants with 385 installed gasifiers. In recent years, growth has been driven by China, predominantly for coal to syngas and chemical intermediates, but new plants are being commissioned all over the world.

The charts below show the distribution of gasification worldwide (for the at least 155 plants that will be operational in 2010) in terms of feedstock, technology suppliers, world regions and final products. On the next page is a table of some important gasification plants around the world.

Figure 16. Key features of the gasification industry in 2010. *Source: World Gasification survey 2004.*



* for comparison, the generation capacity of Italy, the world's 12th largest energy economy, is about 70 GW (electric).

Table 9. Selected commercial gasification installations. (Source: Elcogas.)

Owner/Location	Commissioning	Net output, MW Other products	Fuel	Combined cycle	Gasification
Coal Water, USA	1984	120 MW	Coal	GE 107E	Texaco
Nuon, Buggenum, Holland	1994	253 MW	Coal/wastes and biomass	Siemens V94.2	Shell
Wabash River, Indiana, USA	1995	262 MW	Coal/pet-coke	GE 7FA	E-GAS™
Tampa Electric, Florida, USA	1996	250 MW	Coal/pet-coke	GE 7F	Texaco
ELCOGAS, Puertolano, Spain	1997	282.7 MW	Coal/pet-coke	Siemens V94.3	Entrained flow
SUV, Vresova, Czech Republic	1996	350 MW, vapor	Lignite	2 x GE 9E	Moving bed, Lurgi
SVZ, Schwarze Pumpe, Germany	1996	40 MW, steam, methanol	Lignite/wastes	GE 6B	Noell
Fife Energy, Scotland	2003	109 MW	Coal/wastes	GE 6FA	BGL
St. Iles, Sardinia, Italy	2006	450 MW	Coal	–	Shell
Clean Coal Power, Nakoso, Japan	2006	250 MW	Coal	–	Mitsubishi, air
Piñon Pine, Nevada, USA	–	100 MW	Coal	GE 6FA	KRW, air
Global Energy, Kentucky, USA	–	500 MW	Coal/wastes	–	BGL
Texaco El Dorado, Kansas, USA	1996	40 MW, steam	Pet coke	GE 6B	Texaco
Motiva, Delaware, USA	2000	240 MW, steam	Pet coke	2 x GE 6FA	Texaco
CITGO, LA, USA	2006	570 MW, steam	Pet coke	3 x GE 7FA	Texaco
IOC, Orissa, India	2006	180 MW, steam	Pet coke	GE 306B	Shell
Shell Pernis, Rotterdam, Holland	1997	127 MW, H ₂ , steam	Visbreaker residues	3 x GE 6B	Shell
ISAB, Priolo, Italia	1999	510 MW	Asphalts	Siemens 2 x V94.2K	Texaco
API, Falconara, Italy	2000	260 MW	Visbreaker	ABB 13E2	Texaco
SARLUX, Sardinia, Italy	2000	550 MW, H ₂ , steam	Visbreaker residues	3 x GE 9E	Texaco
Exxon Mobil, Singapore	2000	180 MW, H ₂ , CO	Crude oil	2 x GE 6FA	Exxon
NPHC, Sekiyu, Japan	2003	342 MW	Petroleum residues	MHI 701F	Texaco

Some reference gasification plants.



The IGCC plant “Willem-Alexander” at **Buggenum** in the Netherlands (left) was commissioned in 1993. A 253 MW_e plant (2000 t/d feed), it has a Shell gasifier & Siemens turbines. Buggenum served as an EU demonstration plant in its first years for getting full-scale operating

experience, and also after it started commercial operation in 1999 it has been used for test runs (including co-gasification of biomass). The plant is owned & operated by the utility Nuon Power.

The 340 MW_e **Puertollano** IGCC plant in Spain (right) has a Krupp Uhde (*Prenflo*) gasifier and Siemens turbines. Also originally an EU demo plant, it is owned and operated by Elcogas, a consortium of 8 major utilities and 3 technology providers. Puertollano has been in operation since 1998 mostly on pet-coke and coal, but has also run co-gasification of animal wastes.



These early IGCC plants have been references for many other such projects around the world.

Italy has a law that favours power generation from oil-refinery residues which, since the late 1990's, has stimulated construction of several IGCC plants. The first was ISAB's IGCC complex at **Priolo Gargallo** (Sicily), processing semi-solid oil residues that are fed to a Texaco gasifier, which supplies syngas to two Siemens turbines. It began operation in 1999. **Sarlux** in Sardinia is one of the world's largest gasification plants, 540 MW_e, built by a consortium including Snamprogetti and GE. Sarlux came on stream in September 2000. The electricity produced is sold to Enel. The newest gasification plant in Italy is a 250 MW_e plant using a Shell gasifier, recently commissioned at ENI's refinery in **Sannazzaro** (Lombardy, North Italy). The plant sells power to the grid while the steam is used in the refinery.



The gasification plant at **Shell Pernis** refinery in Rotterdam (left) is an example of processing most of the syngas to hydrogen, which is fed to the refinery's hydro-

cracker. Since its start-up in 1997, the Pernis gasifier processes 1650 tons/day of oil residues, two thirds into hydrogen, and 142 MW of power for use in the refinery/petrochemical complex.

Biomass gasification

The term IGCC* is also used in the biomass literature, to denote gasification of biomass alone using combined cycles, *i.e.* using energy recovered from the exhaust gases to produce further electricity in a bottoming steam cycle. This is considered a suitable path to commercialisation for power production or combined heat and power (CHP) from biomass in a medium-size range (30-100 MW_e). Since biomass can be readily gasified due to its high reactivity, air is sufficient as oxidising medium and fluidised-bed processes, either bubbling or circulating, are preferred, followed by gas purification (see comments below) and a combined gas/steam turbine cycle.

The Värnamo demonstration plant⁴² in Sweden was set up in the early 1990's and showed for the first time that a relatively integrated IGCC process for CHP on a (small) industrial scale can be realised on biomass alone. The plant is rated at 6 MW_e and 9 MW_{th} and uses a pressurised air-blown gasifier having its origins in a design by Finnish company Ahlström for firing lime kilns (dubbed *Pyroflow*), later taken over by Foster Wheeler, operating at nominally 18 bar and 950 °C. At Värnamo, gasification was performed on a variety of biomass fuels for 8500 hours, and the full IGCC process for 3600 hours, between 1993 and 1999, when the plant was mothballed being uneconomic at the electricity prices prevailing at the time.

Currently an EU integrated research project, CHRISGAS, will be re-commissioning the plant for operation on oxygen, with the aim of yielding a more hydrogen-rich gasifier output that could be upgraded to industrial-grade synthesis gas. This would allow demonstrating the production of commercial grade hydrogen, or (more likely) further processing, in a separate future project, to synthetic liquids. The project's time schedule calls for tests of oxygen-blown gasification with biomass at Värnamo to start from the end of 2008.

As long as air is used, the product gases from biomass gasification processes will be too dilute and also need a lot of contaminant clean-up for this to be a conceivable route to hydrogen or syngas meeting industrial requirements. Even for CHP applications, the biomass gasification literature shows that by far the most critical technical issue in the – quite extensive – R&D that has been done is how to control formation of contaminants in product gases: tars, particulates, alkalis, and nitrogen compounds – and how to remove these in an acceptable way.

Perhaps largely for this reason, commercialisation of biomass CHP via gasification has fallen short of expectations. Except for Värnamo, and a smaller scale two-stage CFB gasifier demonstrated at Güssing, Austria⁴³, most approaches tried have so far failed to pass the early stages of technology demonstration. Nevertheless, many promising developments are on-going, the vast majority using CFB, although some use bubbling beds *e.g.* Finnish-Californian Carbona⁴⁴, who are demonstrating a derivative of GTI's *Renugas* process in a recently commissioned plant at Skive (Denmark) with both US DoE, EU and Danish support funding. Very few are pursuing fixed/moving-bed concepts, one being a novel version of the updraft *Bioneer* gasifier that had a certain use in Finland in the 1980's; these also should have a pilot plant by now⁴⁵. There are a few multi-stage approaches; worth noting is the *Carbo-V* process – an original 3-stage system incorporating a small entrained flow gasifier⁴⁶.

If any of these projects are successful and the tar problems finally solved, a breakthrough can be expected that will allow gasification of biomass to meet international power-plant standards. However most ongoing efforts are very focused on CHP performance, meaning that neither the processes nor specific advances expected would not be easily adapted to hydrogen or syngas.

* or BIGCC for "Biomass". Also "BIG/GT"; more precise name "biomass-fuelled gasifier coupled to Combined Cycle".

The IEA Bioenergy program closely follows these a number of other on-going projects aiming to achieve an industrial level of technology in gasification of biomass for CHP, as does the EU and the US DoE concerning the projects in their support portfolio.

A current EU project of interest in the context of continuation of the present work is BIOCUP, led by VTT and with Shell as a core partner, which looks not explicitly at gasification but at how biomass-derived feedstocks can be co-fed to and used in conventional oil refinery processes.

A range of small to medium scale, stand-alone gasifiers producing fuel gas, heat and electricity (via small steam cycles, or engines) from available biomass residues have been widely used in countries like India and China ⁴⁷. While useful in valorising crop wastes, many such units are of relatively “low-tech” having poor conversion efficiency, and today being phased out in favour of centralised energy distribution in many areas. An extensive review of manufacturers in USA, Canada and Europe ⁴⁸ identified over 50 companies offering more-or-less commercial gasification plant, the majority atmospheric downdraft fixed-bed systems of capacity up to 1 – 2 MW_{th}. As mentioned, these can be attractive for small scale applications using opportunity fuels; there is a market in both developed and developing countries. Industrial application would be made more favourable by automated operation, as offered by some suppliers. However, this class of gasification process is not easily scaled up, and low efficiency and tar present major problems. It is generally outside our scope of interest in terms of producing hydrogen from biomass.

IEA Bioenergy addresses the world-wide effort on biomass gasification at all scales through a dedicated Task group*. Excellent reviews of biomass gasification are available, covering topics ranging from the technology status ⁴⁹, via the role of gasification in a bioenergy R&D context ⁵⁰ to the historical background of process development ⁵¹, all focused on biomass-specific issues and with a deep comprehension of the ongoing specialist efforts worldwide.

In view of the limited degree of industrialisation achieved with dedicated biomass gasification, it is concluded from our technology analysis that – at least in the near to medium term – the best way to achieve an industrial process route from biomass to hydrogen is by introducing biomass as a blend feed to the more mature, commercially proven, gasification technologies dominating the world market. Pressurised, oxygen-blown entrained-flow gasification has found a prominent place in this market, and technology suppliers as well as the industrial gasification marketplace in general is accustomed to handling a wide variety of fuels. It is considered that the greatest challenges in developing a credible biomass-to-hydrogen (or biomass-to-syngas) pathway, via co-gasification with proven fuels, are those in biomass feedstock selection, logistics and, above all, feedstock availability and consistency. This is in contrast to dedicated biomass gasification, which has a long way to go for the basic technology to be market ready. While significant, the technology risks of feeding ash- and chlorine-rich biomasses to an entrained flow gasifier are considered to be manageable in an industrial gasification context by exploiting the experience and variety of solutions available, so that an effort to address these risks can be justified by the potential value of a success. The flexibility in terms of co-gasification feed ratios means that a wide range of biomass volumes could be processed. Early experiences with pilot projects on co-gasification and likely interest from the gasification/power industry are both encouraging.

* Task 33, led by Dr. S. Babu, to whom the Subtask B team is greatly indebted for sharing his vast experience with us

Fischer-Tropsch biodiesel from gasified biomass

The concept of producing so-called second generation biodiesel via biomass gasification and F-T liquid synthesis was discussed in the “Markets” section. However the immature technical state of biomass processing places some additional constraints on this processing route.

The process parameters (pressure, temperature, catalyst...) influence the properties of the final synthesis products significantly. As a consequence, liquid biofuels with very specific properties can in principle be designed. However the experience with F-T synthesis is largely empirically built and since the use of biomass has been much less common industrially than e.g. coal, data is lacking. No gasification system fulfils so far “ideally” the demands for synthesis of F-T liquids. A syngas conditioning system (processing train) is necessary in any case but, for synthesis gas derived from gasified biomass, at least when using lower-temperature gasifiers, the appropriate gas cleaning technologies and systems remain unoptimised with basic optimisation parameters unknown. The costs of the gas cleaning, which for biomass processing may amount to 50 % of the overall investment, have to be minimised by selecting adequate gasification systems. With biomass alone, due to its high reactivity, fluidised bed and multistage gasification processes do offer good preconditions for the syngas production, but the technology is very demanding and partly not very well known.

For these reasons, it is believed that in principle lower technical risks as well as greater market potential can be achieved also for liquid biofuels by aligning the development effort in the frame of co-gasification, in roughly the same way as was explained for hydrogen. However, the earlier, currently much greater “market pull” for biodiesel, with pilot plants and early production facilities being implemented already, may be sufficient to overcome the technical risks. Notably, the high prices possible to charge for any biodiesel in today’s high oil price market (officially considered by IEA and most Member State governments to be a temporary situation) may overshadow the risks in making investment decisions – at least for moderately sized plant. This is different from the case for hydrogen, because its demand drivers are complex and all rooted in the future.

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Section III – POTENTIAL APPLICATIONS

III.1. Using H₂ from biomass as a blend combustion fuel

Hydrogen from any source including biomass can be used just like a conventional fuel: burned using air in engines, turbines or boilers to provide useful energy. But in addition, hydrogen can be converted to electricity directly, without the thermodynamic limitations of a thermal process, in nearly all types of fuel cells. (Only very few other fuels can be converted in this way and then only in very specific types of fuel cells.) When hydrogen is used as a combustion fuel with air, minor amounts of polluting emissions will result, mainly NO_x due to high-temperature reactions with nitrogen in the air. Appropriate adjustment of the combustion device (burner, engine, gas turbine...) taking account of the specific properties of hydrogen will in most cases reduce such noxious emissions to much lower levels than common with hydrocarbon fuels. In the case of a fuel cell, the only emission will be water vapour.

Conceivably, hydrogen from biomass or other sources could be added to the gas transmission and/or gas distribution grid, and the resultant blended gas used essentially in the same way as gas is today. This represents no new situation, in view of the fact that “town gas” manufactured by gasification of coal (or, although rarely, wood!) contained about 50% hydrogen by volume for more than a century in the majority of industrialised countries. In contemporary energy markets, a potentially highly attractive benefit specifically for H₂ from biomass (and other renewables) is the consequent lower net emissions of CO₂ for a given amount of energy consumed. The drop in emissions would be roughly proportional to the degree of addition of such “green hydrogen”. (but see later for more precision on what basis this is calculated upon).

Considerable variation already exists in distributed gas composition and properties both within and among countries. Typically the gas properties are regulated but allow substantial variation. Table 10 shows an example for Europe, where gas currently is generally either “H” or “L” gas depending principally on the heating value.

Table 10. Typical L- and H-gas compositions and properties compared to Groningen field composition. *Source:* Gasunie.

Composition	Groningen-gas	Typical H-gas (North Sea)	Typical L-gas (onshore Netherlands)
N ₂	14%	1.50%	38%
CO ₂	1%	0.30%	0.70%
CH ₄	81.60%	96.20%	58.80%
C ₂ H ₆	2.70%	3%	2.10%
C ₃ H ₈	0.50%	0.50%	0.30%
C ₄ +	0.20%	0.40%	0.10%
Properties:			
NCV (MJ/m ³)	31.8	34.8	22.9
GCV (MJ/m ³)	35.2	38.6	25.4
Wobbe (MJ/m ³)	43.9	49.3	26.9

Incidentally, the majority of public regulations and standards for the previous “gas family” of town gas are still in force in most markets, making a hypothetical re-launch of blended H₂ + hydrocarbon gas quite straightforward from a legal and regulatory point of view.

Obviously, the technical and, first and foremost, the market issues could represent major hurdles.

It is noteworthy in the context of discussing both hydrogen blending and other aspects of a shift to hydrogen that gas grids both in Europe and North America are in fact “transition-proven”, in the sense that a major shift in the composition of gas delivered has been already successfully carried out within “living memory” of the industry – less than 40 years ago in many countries.

Three studies have been assessed by the Subtask B group with a view to identifying specific issues relating to H₂ from biomass in this context: a Danish study presented in 1999⁵², an IEA study for the Greenhouse Gas programme completed in 2003⁵³, and an EU supported project (*NATURALHY*) led by major European players in the gas industry⁵⁴. The latter is still ongoing.

The Danish study outlined the possibilities and restrictions for adding hydrogen to the existing distribution & transmission grid. Notably, Denmark has a high quality gas grid designed from the ground up for natural gas. Previous experience with H₂ blends around the world was first reviewed. With basis in Danish gas properties and national regulations, it was found that the upper limit for hydrogen addition is 17% volume, based on the demands for relative density, and 25% based on demands for the Wobbe index.

However, hydrogen additions above 1-2% can cause operational problems or losses in output for Denmark's more than 1000 ICE-based CHP power stations. These engines can be adjusted or modified to run adequately on H₂ blended gas – but not necessarily with the same efficiency dependent on engine design. Moreover, most CHP engines will need re-tuning if the hydrogen content varied more than a certain amount (margin is unspecified, but probably not very large). In contrast, most normal domestic gas equipment of the quality used in Denmark could tolerate up to 5% hydrogen blending without adjustment. An admixture of 10% H₂ will not give material problems or considerable operational limitations in the grid. If the admixture is larger, several areas may need to be looked into, such as lubricants, meters, regulators, odourisation, and mechanical strength of tubes and weldings.

Altogether, the Danish study showed that blending hydrogen in this country's national grid at up to 10% volume would be essentially unproblematic in itself, and feasible, but would imply costs for re-tuning equipment, specifically the CHP plants. Thus it is important with a user distribution such as the one in Denmark to maintain a constant blend ratio of hydrogen as far as possible.

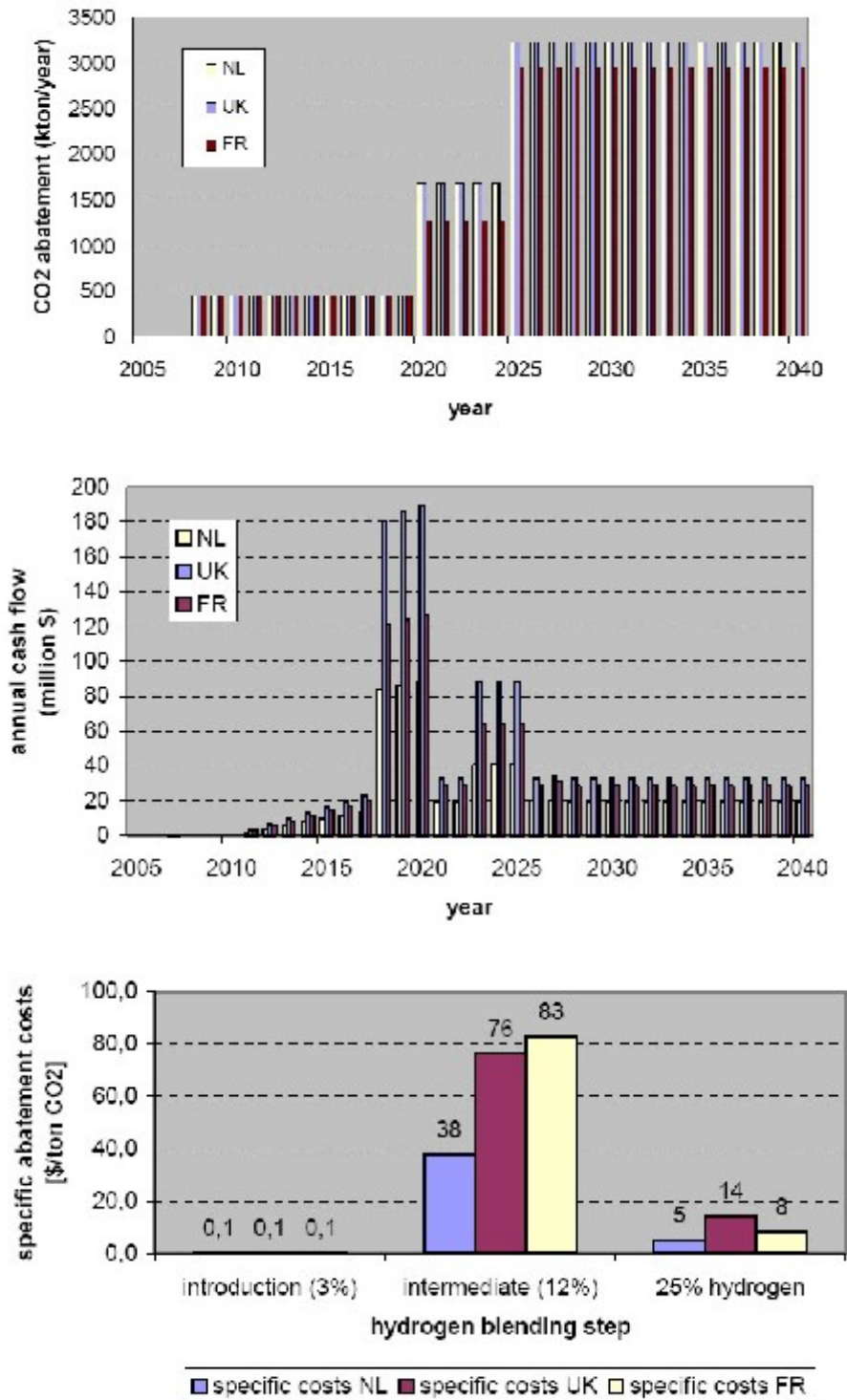
The IEA GHG study reached much the same overall conclusions as the Danish one but went several steps further: quantifying both costs and benefits of hydrogen addition. In particular,

- Three EU gas markets of different technical and operational constraints were analysed, viz. Netherlands, UK and France
- Hydrogen blending was studied in three steps:
 - o Introduction, to 3% by volume;
 - o Intermediate step, to 12%
 - o Maximum blending in the ultimate steps (after 20 years) to 25%
- Costs were assessed for each step as were the benefits in terms of CO₂ abatement

Figure 17 shows some of the most important results obtained in terms of costs, benefits and specific CO₂ reduction costs. Clearly the benefits are significant but costs are relatively high, also compared to costs of CO₂ capture & storage. Thus the report notes, essentially in general agreement with the Danish one, that blending is a quite feasible proposition in itself, but that careful attention must be paid to the steps, benefits and how blending is implemented.

In summary, the IEA GHG analysis appears to be thorough, accounting for a large number of scenarios, factors and critical elements. It recommended looking at local/regional opportunities for blending in some areas, combined with scenarios for carbon storage and hydrogen zero-emission power generation. This is in fact an interesting background for biomass-derived H₂, especially in a case where market conditions and/or local availability of "green" hydrogen work to preclude a widespread use for other, higher efficiency conversion routes.

Figure 17. Estimated CO₂ abatement benefits (top), costs (middle), and specific abatement costs (bottom) for a phased hydrogen blending scenario into grid-distributed gas in three EU countries: UK, France and the Netherlands. (Source: IEA Greenhouse Gas programme)



A comprehensive approach to the production, handling and use of H₂ mixtures is taken by the ongoing NATURALHY project. It includes both direct use of blends and addressing the (so far hypothetical) separation of pure H₂ from future gas blends gas.

NATURALHY addresses the following seven questions:

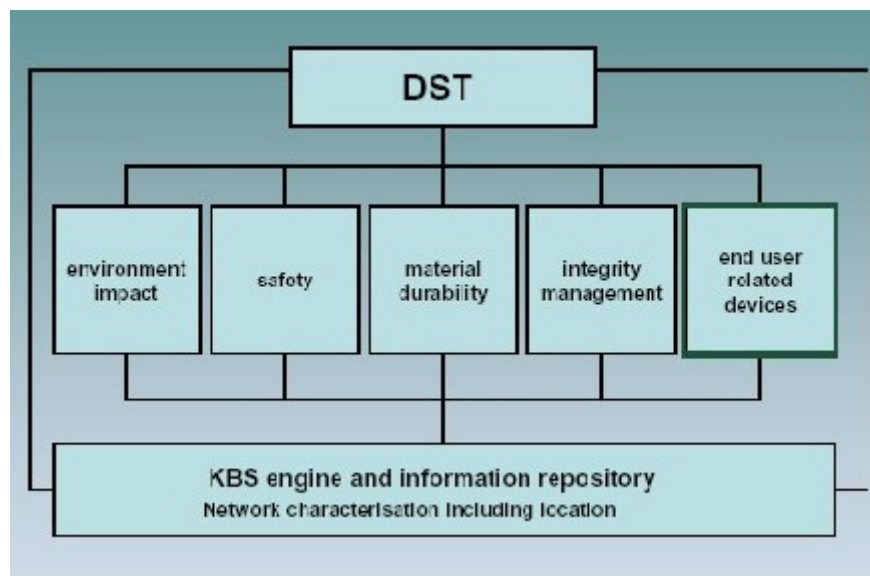
- How much H₂ can be added to natural gas with acceptable consequences?
- What are the life-cycle and socio-economic consequences?
- Is the public safe of H₂ is introduced into the existing gas systems?
- What is the impact of H₂ on the durability of current NG networks?
- Can gas networks that include H₂ be maintained effectively?
- How much H₂ can NG appliances accept?
- How do we take H₂ out of the natural gas network?

Several of these issues are of at least peripheral relevance to hydrogen derived from biomass. Conceivably a hydrogen-containing variety could be considered as a “green gas” (as a parallel to “green electricity”). This remains a possibility, especially for hydrogen from biomass.

The perspective of the ongoing work is naturally (...) that of the gas production and distribution companies who will be the ones charged with both implementing any massive transitions – so a clear and strong business case benefiting also these players is a prerequisite for success.

It should be noted that several major gas companies are active players as stakeholders in the EU and international effort for hydrogen, including IEA and that concerned with biomass. One particularly interesting result of the project is a decision support tool for predicting challenges and estimating the costs for introducing and carrying H₂ mixed with Natural Gas for certain mixture percentage levels. This computer tool incorporates modules for the various critical aspects and issues of large-scale hydrogen admixture.

Figure 16. Simplified block diagram structure of decision support tool (DST) for H₂ admixture.



Source: Naturalhy project

III.2. Using H₂ from biomass as a fuel for FC's

The most efficient use of hydrogen, whether for transport or stationary uses, can be made by electrochemical conversion to electricity in a fuel cell. Fuel composition and purity is an issue for many different hydrogen applications *. Table 11 lists the main fuel cell classes.

Table 11. Main classes of fuel cells and their characteristics in terms of H₂ fuel contaminants. Concentrations in ppm indicate maximum level recommended (mean of several estimates)

impurity	Alkaline	Phosphoric acid	PEM	Molten carbonate	Solid oxide
CO	Sensitive (max 10 – 100 ppm)	Max 0.5 – 1%	1-10 ppm range	Good fuel	Can be fuel
CO ₂	Sensitive (max 10 – 100 ppm)		1-10 ppm range		
CH ₄			To avoid as far as possible	Can be fuel (int. reforming)	Can be fuel (int. reforming)
CxHy			To avoid	unproblematic	Unproblematic
H ₂ S	sensitive	Max. 50 ppm	<1 ppm	Max 0.5 – 1 ppm	Max. 1 ppm
NH ₃	insensitive	Little sensitive	sensitive, <1ppm?	unknown	Not certain

Blank fields indicate the listed “contaminant” has no effect except to dilute the hydrogen fuel.

Thus H₂ is the best or only fuel for all classes except MCFC and SOFC. Molten carbonate FCs will not run on pure hydrogen, and solid oxide FCs generally gain little from being fed hydrogen compared to other, usually cheaper fuels such as natural gas. However, both high temperature fuel cell types can run quite well on synthesis gases, with some limitations (*e.g.*, SOFC's would be more resistant to sulfur than MCFC's). Actually, a syngas stream of reasonable purity might be close to the ideal fuel for a molten carbonate system. This is relevant for biomass especially for distributed small scale gasification where syngas may be produced in volumes and qualities that do not merit further purification, but could in fact be processed in distributed MCFC/SOFC. Some demonstration units of this kind have been displayed. Obviously, like for other biomass gasifiers, the tar and other problems with small scale would remain to be solved.

MCFC's are in pre-commercial stage, with 250 kW_e CHP units available in North America and EU at prices of some thousand euros per kW, whereas SOFC is currently – in most observers' view – back in the “developmental” stage after some unsuccessful commercialisation attempts.

PEM fuel cells are sensitive to hydrogen purity, due in part to their low operating temperatures, which make the catalytic components prone to contamination. In general, most manufacturers specify limits of ppm level or less of sulfur and CO on their current prototype systems; ammonia can also be a catalyst poison in minute quantities. Some hydrocarbons may also be in the risk category for PEM. However, it is widely expected that the PEM fuel cells finally incorporated in vehicles for mass markets will be several generations of development away from those being tested today. In particular, efforts aim at operating at higher temperature (120-180 °C vs. 80 °C today). These ongoing improvements should reduce the sensitivity of PEM FC's to impurities in such a way that conventionally reformed natural gas hydrogen (equipped if required with a PSA (Pressure Swing Adsorption), post-processing step) can be used. And since we are considering gasification as the main route to hydrogen from biomass, the composition of this hydrogen will be essentially the same in terms of any potentially PEM-cell-damaging component.

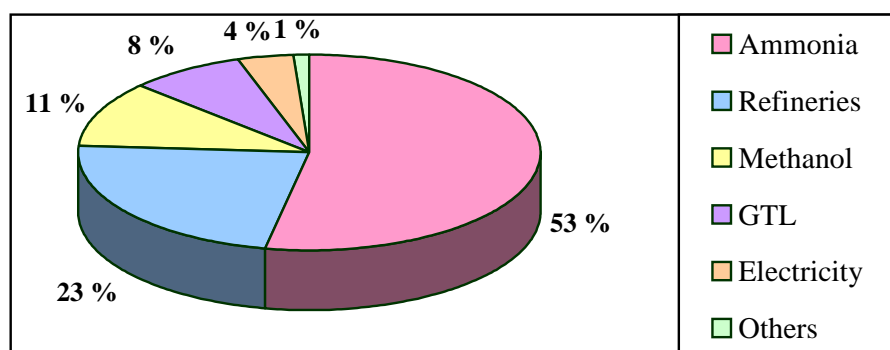
* Despite the simple finding that H₂ from biomass via gasification will be of comparable purity to that from natural gas, thus applicable also to mass markets, a thorough treatment of purity requirements is obviously crucial for developing a hydrogen infrastructure. Conclusions on purity should encompass end-use requirements and cost-competitiveness of different processes for an expected purity vs. process scale feasibility (gas clean-up complexity and scalability).

III.3. Syngas or hydrogen?

Apart from its fuel applications, biomass-derived hydrogen should be also considered within a broader context as a feedstock to produce other fuels and chemicals. Hydrogen can be used alone as a chemical feedstock, but mostly as synthesis gas, the mixture of CO and H₂ that is the main output of steam reforming of natural gas as well as gasification of solid fuels. Today, more than 80% of world syngas is produced from natural gas; the share from coal is growing again due to high natural gas prices.

Besides the obvious GHG advantages, switching part of syngas production from fossil sources to biomass will bring diversity of supply benefits owing to the different production patterns of biomass to those of natural gas and coal. The main outlets for syngas and/or hydrogen as a chemical feedstock are ammonia production, methanol production, use in petroleum refining, and the production of synthetic Gas-to-Liquid (GtL) fuels.

Figure 19. Current breakdown of world synthesis gas market by applications



Source: Van Der Drift A. et al. (2004) *Bio-Syngas: Key Intermediate for Large Scale Production of Green Fuels and Chemicals*, 2nd World Conference & Technology Exhibition "Biomass for Energy, Industry and Climate Protection", Rome 2004

Main outlets for syngas

The demand for **ammonia** (the second most used synthetic chemical worldwide) is driven by the nitrogen fertiliser industry. The market for nitrogen fertilisers depends on food markets, primarily cereal markets. When the supply base of cereals is tight, leading to a raise in cereal prices, the demand for and prices of nitrogen fertilisers also increase. According to the UN Food and Agriculture Organisation (FAO), since 1999 both world absolute and relative (stocks-to-consumption ratio) cereal stocks have been steadily going down to historically low levels. The pressure on world cereal stocks is projected to remain in the future due to the continuous growth of world population, so further reduction in world cereal reserves is possible. As a result, world demand for cereals will keep growing, pushing up cereals production and, consequently, the demand for nitrogen fertilisers.

Methanol is amongst the top ten chemicals in the world. Currently the building industry is the major buyer of methanol, used in the manufacturing of formaldehyde. Another key methanol outlet is the organic chemistry industry, which uses methanol in the production of acetic acid – a semi-finished product with multiple applications. The demand for a number of end-products whose manufacturing is also based on methanol, e.g. ethylene and propylene, is expected to undergo a significant growth over the next 10-15 years.

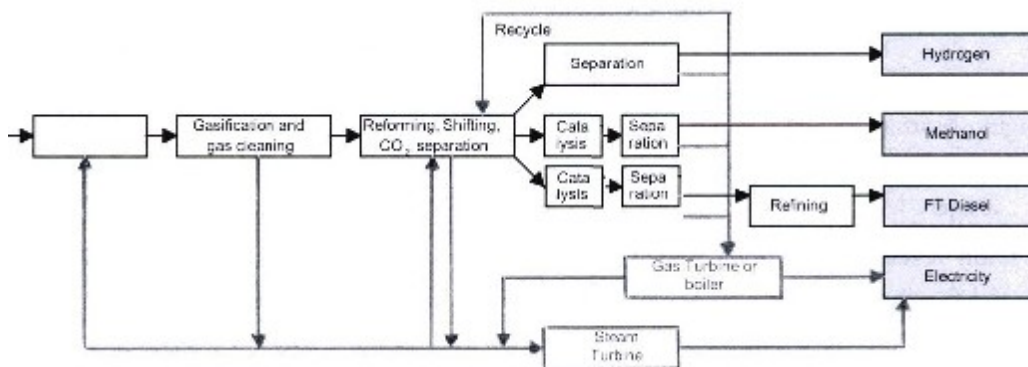
At present **oil refining** is the second largest consumer of syngas, in the form of hydrogen. Most is used in the hydrocracking and related processes for upgrading of feedstocks. Refineries are being forced to resort more widely to hydrocracking for meeting new, stringent quality criteria for clean, aromatic and sulfur-free automotive fuels. This trend is expected to sustain continued high growth in demand from refineries for hydrogen.

Gas-to-Liquid is another still modest, but fast growing consumer of syngas for the production of synthetic liquid fuels using Fischer-Tropsch synthesis. A well known technology, used on a massive commercial scale first during the 1930's*, GtL has seen a renaissance recently due to restrictions on flaring of associated gas in oilfields in parts of the world without gas distribution. GtL has been found an attractive outlet for such "stranded" gas. With many products of equal or better properties to those from conventional oil refining, GtL plants can address many markets of oil refinery products using feedstocks other than oil (coal was the traditional source of F-T liquids, and still is in South Africa, China and India).

Since they are synthesised from gaseous raw materials and not separated from crude oil, GTL products are "cleaner" than oil products, essentially sulphur free in particular. In GtL processing the optimum distribution of fractions can be optimised to a greater extent than in refining to give high-demand fractions such as some middle distillates. All in all, GtL is expected to undergo a fast and intensive growth due to rising demand for cleaner fuels in transport and the objectives to diversify energy supply for transport, today almost fully dependent on crude-oil derivatives. Even those GTL fractions that are not appropriate for fuel application (naphtha, waxes) can find market as chemical feedstocks, as their properties may be better than oil-derived analogues.

However, as Figure 20 shows, the processes concerned are strongly interrelated so that plants processing syngas (derived from biomass or other sources) may be designed in a modular way to take advantage of shifting market conditions. Hydrogen and liquid products are therefore not mutually exclusive, but rather synergistic options. The downstream processing uses mostly off-the-shelf-technologies, so investment decisions are relatively straightforward.

Figure 20. Simplified process diagram showing the interrelation of hydrogen, methanol and synthetic liquid fuels production.



* GTL, the production of synthetic liquid fuels from (coal) gasification was patented in 1926 by German scientists Fischer and Tropsch, known also as Fischer-Tropsch synthesis. GTL fuels became an important part of German war-time energy supply but the process lost most of its application to oil after World War II.

The benefits of polygeneration

As already noted, industrial scale production of hydrogen and a number of fuels and chemicals is mutually inter-related. Thus, it appears more appropriate to target maximisation of cumulative revenue from all syngas derivatives – hydrogen, fuels, non-energy products, chemicals, power – than to look at maximisation of the revenues separately by items, such as for hydrogen alone.

From an industrial point of view, cumulative maximisation of revenue is always achieved via the aggregated optimisation of the cost and energy efficiency of all syngas pathways, instead of optimising the energy efficiency of single syngas derivatives. Considering not only the use of biomass as a source of hydrogen, but as an essential part of a *polygeneration* process – the combined production of fuels, chemicals, power and heat – thus seems an optimal approach to hydrogen from biomass from a techno-economic point of view.

Synthesis gas derived from biomass can be used both to produce hydrogen as an end product, and as a feedstock for producing a wide range of chemical products and liquid fuels as well as hydrogen. With the appropriate level of technological and economical maturity, biomass could replace fossil raw materials on a large scale. In both cases, in the future carbon-constrained economy, the biological origin of the primary feedstock could give biomass advantages over fossil feedstocks that may offset – directly or indirectly – its higher cost.

Of course, a main driver for the direct application of hydrogen as a fuel is the avoidance of CO₂ emissions at the point of use – a major advantage compared to all other fuels. However, and in view of the long time lag associated with developing market-ready hydrogen vehicles as well as an efficient hydrogen fuel distribution system, it might be an attractive option – especially in the near term – to consider biomass-derived hydrogen as a feedstock with the potential to replace a significant part of the fossil fuel-derived hydrogen feedstock for syngas.

Since any CO₂ derived from biomass in principle does not add to man-made GHG emissions (other than that from other energy sources used in growing, transporting and processing the biomass), industrial use of synthesis gas derived from biomass as a “green feedstock” may be a good alternative to reach earlier marketability for many bioenergy resources, considering the techno-economic constraints of hydrogen fuel application.

Using biomass derived syngas as an industrial feedstock could be a first step and compensate for the delay of growing large markets for hydrogen as an energy carrier. And as we have seen, *all* the upstream problems, *most* of the mid-stream processing issues, and a fair number of the challenges with product clean-up (downstream of the gasifier) are shared between biomass-to-hydrogen and biomass-to-syngas. Thus, promoting “bio-syngas” for already existing industrial markets could significantly and synergistically lower the threshold to future technical maturity and commercial acceptability of hydrogen produced from biomass as a major energy carrier.

What is the most “CO₂-efficient” use of biomass?

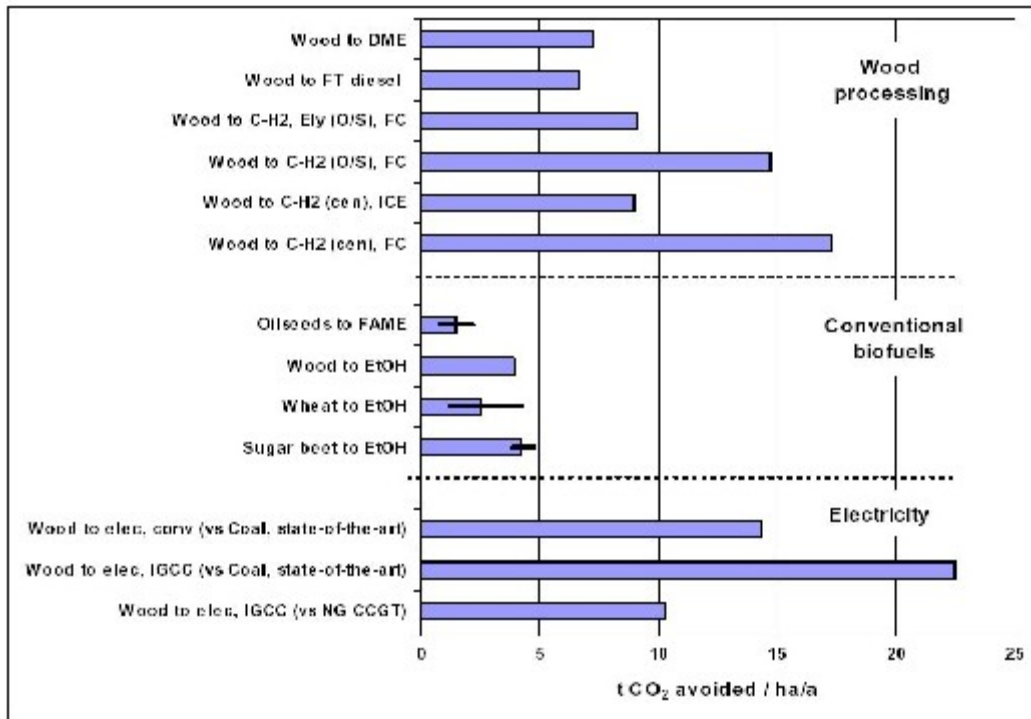
Land is the common and limiting factor for all uses of biomass. When discussing the merits of different energy products and processes from biomass in terms of their potential for replacing fossil-fuel derived CO₂ emissions, it thus makes sense to compare the specific CO₂ emission avoidance per area of land (agricultural or forested) with different options.

Few such calculations are known, however, one was presented by the European Commission *Alternative fuels contact group (AFCG)* ⁵⁵ in late 2003 using data from the widely quoted CONCAWE study. The analysis is based on a simplified but comprehensive set of well-to-wheel calculations and was endorsed by a broad group of stakeholders.

A part of the AFCG conclusions relevant to our topic is reproduced below in Figure 21.

Note that “wood” was used by the AFCG as a proxy for all high biomass yield energy plants. The CO₂ avoided was estimated by comparison to a base case scenario (*e.g.*, one EU average hectare planted with wheat can produce an amount of ethanol which would substitute fossil gasoline as fuel to a petrol engine vehicle. The same hectare if planted with wood could alternatively produce *e.g.* hydrogen for use in a FC vehicle, substituting a mixture of fossil petrol or diesel used in conventional vehicles).

Figure 21. Amount of CO₂ avoided by use of energy from biomass per hectare land per year.



Interestingly, this analysis shows that hydrogen made from biomass *used in fuel-cell vehicles* is by far the most efficient product in terms of CO₂ avoidance per hectare of land used, more than twice as efficient than next generation biofuels, and vastly better than current biofuels. The key is the greater energy efficiency of fuel cells; if the H₂ is used in an ICE engine instead, the advantage of biomass-derived H₂ over liquid biofuels is less pronounced, at the order of 20%.

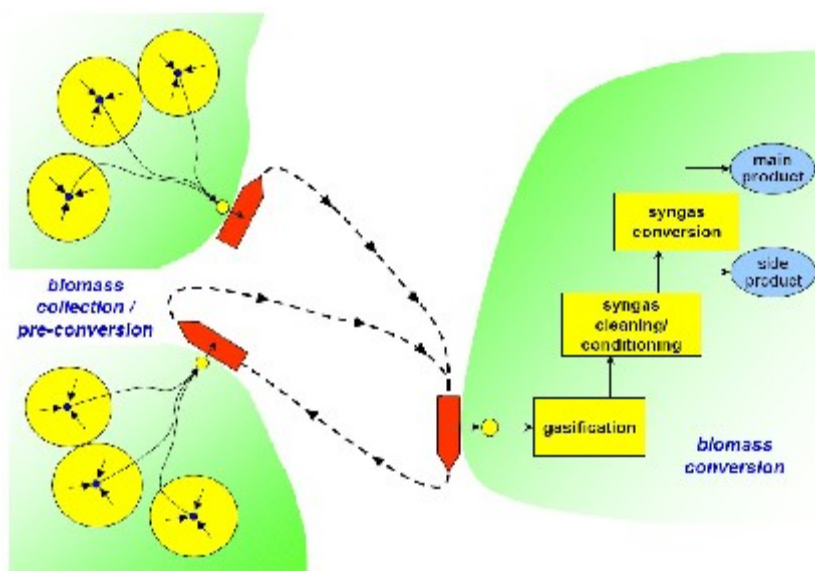
The analysis also showed that electricity from biomass using the most modern efficient process – IGCC for power – represents the only even more “CO₂-efficient” use of land than producing hydrogen for fuel cell vehicles, although only if used to displace conventional coal-fired plant.

Interestingly, the combination of hydrogen fuel and power using co-gasification of biomass in existing IGCC plant, as proposed in the present study, merges these two top-ranked benefits. The AFCG findings thus highlight the potential of biomass to achieve the most area-efficient emission reduction by *simultaneously* producing electricity and hydrogen fuel. Noting the flexibility towards product as well as of feedstock that is characteristic of IGCC, it is clear that processing biomass to hydrogen *together with* electricity will by far be the most efficient way of using agricultural land.

Of course, it remains to verify that the economic and other parameters are equally favourable. However, the result of such an analysis is expected to be encouraging: This is because the co-gasification of biomass together with coal and other fossil fuels adds the final advantages that have so far prevented biomass to penetrate the mainstram of power generation and hydrogen from biomass to find a clear path to commercialisation, *viz.* economies of scale, and access to a large number of adequately sized power plants operating in a commercial market worldwide.

In light of the indications above, the concept of IGCC, within the “integral-split” process concept discussed in II.3, would be a highly elegant way of satisfying the combined needs for emission efficient electricity and a highly attractive kick-start of the market for green hydrogen. Below is an artist’s impression of the transport scenario as imagined by Shell in their published work; it is obvious that an even better combination of transport/logistics as well as the pre-processing / gasification scheme can be achieved with multiple co-gasification sites each taking a fraction (5, 10, 20% ...?) of biomass added to their already on-going, commercial processing of coals.

Figure 22. Artist’s impression of split biomass pre-processing and gasification combined with biomass intermediate (e.g. pyrolysis oil) being globally traded by sea. *Courtesy of Shell.*



III.4. Co-gasification: a path to the mainstream?

Gasification of biomass vs. of Coal

Gasification of biomass is recognized as a valid process for power and heat generation, as it allows achieving both high relative efficiency and good environmental performance, relative to conventional combustion processes. Gasification also represents an attractive process for biomass conversion into hydrogen, as the feedstock can be converted into a synthesis gas, containing mainly carbon oxides and hydrogen, and the hydrogen yield can be subsequently increased by syngas reforming and water-gas shift.

Biomass gasification technologies generally have followed a different path of development from the corresponding technologies for coal, essentially for the following reasons:

- The high reactivity of biomasses, which is related to their high volatile content, allows the use of temperatures between 800 and 900 °C, *i.e.* much lower than those normally used in coal gasification;
- Because of this high reactivity, air can be used as oxidant, while oxygen is normally used in coal gasification;
- The low melting point of biomass ashes, due to the alkali content, requires the use of relatively low temperatures to avoid slagging and plugging phenomena in the process.

As reviewed in Sec. II.4, the available gasification technologies are categorised as fixed bed, fluidized bed, and entrained flow gasification. Historically, all of these were developed for coal gasification, and their application to biomass requires particular considerations.

A fixed bed gasifier is a refractory vessel where fuel is fed from the top and air from the bottom in counter-current flow (updraft system); or where fuel and air are fed both from the bottom in co-current flow (downdraft system); ashes are collected with unreacted carbon (char) in the bottom of the gasifier. The use of biomass in a fixed bed gasifier requires operating at low temperatures in order to avoid the plugging by ashes, resulting in a high content of tar in the syngas and of char in ashes. For these reasons, the use of fixed-bed reactors in biomass gasification is limited to small and relatively “low-technology” applications, outside the scope of our work as they do not represent a pathway to hydrogen.

Fluidized beds is the most widely used technology for biomass gasification, especially the CFB (circulating fluidized bed) gasifier. It operates with higher fluidization velocity than the bubbling fluidized bed (BFB) gasifier, resulting in a density gradient from the bottom of the gasifier to the top. Entrained media and char fines are recycled back to the gasifier via a cyclone. The higher velocity regime increases char residence time, while improving gasification yield and reducing reactor size with respect to the BFB. CFB gasification of biomass has been widely investigated at laboratory and pilot scale by R&D centers of several academic and industrial organizations. Several demonstration projects for the gasification of biomass and waste have been carried out and some have achieved their operational phases^{56 57} as mentioned in Sec. II.4.

Nevertheless, and despite growing interest spurred by the rising cost of oil and gas, biomass gasification today still is widely perceived as a niche technology, outside the scope of primary interest of major industrial operators. Its ability to become a mainstream energy technology is limited by several issues, such as the high specific cost of technologies related to the relatively small size used so far, and specific issues related to biomass cost and availability.

Entrained flow gasification

Today (*cf.* II.4) entrained flow gasification technology is commercial and has achieved a consolidated industrial level for fossil fuels. Concerning pressurized coal gasification using oxygen, the worldwide applications market is dominated by two versions of this technology, differing in terms of the system used for feeding. The “Texaco” gasifiers, now owned by General Electric, is based on feeding of a coal/water slurry, whereas the Shell and the Prenflo (Krupp-Uhde) processes mostly use dry feeding.

Conceptually, biomass can be gasified alone in entrained flow gasifiers, but this is not normally considered. EF gasifiers require finely ground feed that is very energy intensive to prepare from most biomass resources. Also, in order to achieve complete gasification in the short residence time typical of entrained flow conditions, temperatures of 1200 – 1500 °C are typically used, with ashes removed as a melt. The high alkali content of biomass ashes presents considerable danger of damaging the firebrick liner of the reactor wall. Hence, it is not surprising to find little technical experience available for the entrained flow gasification of biomass by itself.

The IGCC power plant owned by Nuon Power at Buggenum (NL), which uses a Shell gasifier, is the only case for which some data for practical co-gasification of biomass are well analysed. They achieved encouraging results with successful co-gasification of several types of biomass, and near term plans for co-gasifying up to 30% biomass (*i.e.*, 120,000 tons/year) at this plant have been made. The tests indicated that good management of co-gasification flows must be very well managed to preclude any risk of damaging the integrity of the refractory wall. In sum, the (limited) Buggenum experience confirms that co-gasification of biomass in entrained flow can be an attractive solution in the context of co-gasification with fossil fuels, especially coal.

Advantages and challenges of co-gasification

Once the feasibility of this concept has been convincingly demonstrated, indications are that co-gasification of biomass and coal can potentially result in a reduction of investment cost as well as an improved efficiency compared to separate gasification facilities for the two fuel types.

The combined gasification of biomass and fossil fuel, particularly coal, provides a wide range of advantages with respect to stand alone processing of each feedstock:

- Reduction of specific investment cost, which is very high for the small sized, standalone applications realised so far for the gasification of biomass alone
- Reduction of problems related with the seasonability and availability of biomass
- Improving of efficiency by allowing operation in a greater system than for dedicated biomass gasification facilities
- Economic benefits for utilities that operate coal gasification cycles, by reduced CO₂ emissions, by the combined use of a renewable fuel; and finally
- Exploitation of potential process synergies related to the properties of the two fuels.

In order to realise this potential, it is important to develop a versatile technology that can benefit from using a variety of fuels to mitigate the problems of biomass availability and differences in composition. Its use in combination with coal – besides vastly increasing potential market and mainstream acceptability of biomass – could contribute to providing more stable gasification conditions and solve otherwise insurmountable problems due to biomass seasonal variability.

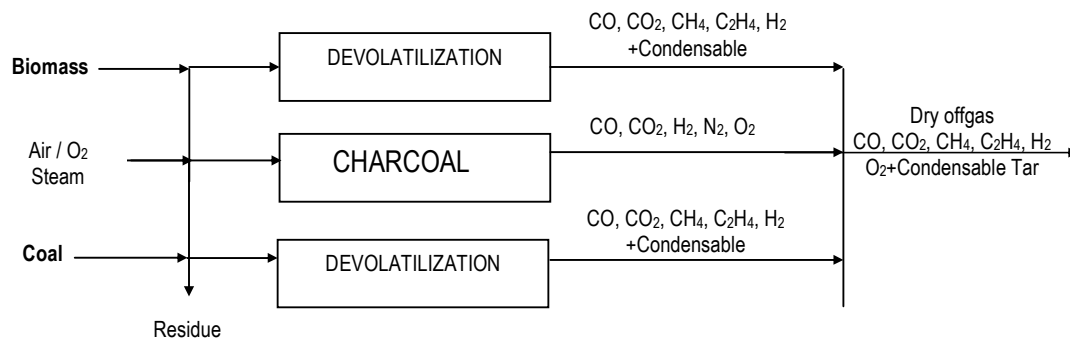
Although in literature, there is a large scientific knowledge on separate gasification of both coal and biomass, gasification of a mixture of the two fuels is still under development and requires further investigations. In addition to the Buggenum tests mentioned, three particular cases of demonstration and systems studies on co-gasification are considered relevant:

- VTT (Finland) reviewed co-gasification of coal and biomass and confirmed that biomass wastes could be used as an additional feedstock in large IGCC plants. Through experimental analysis carried out in a PDU-scale pressurized fluidized bed, VTT demonstrated the technical feasibility of operating an IGCC system using different blend of wood and coal up to 50% of biomass, without problems of ash sintering, tar loading and other operational problems^{58 59}
- in the USA, the Department of Energy signed a cooperative agreement with TECO Polk Station to carry out demonstration of closed loop biomass in a 220 MW IGCC using a Texaco gasifier [3]. A test blend of 55% petcoke, 44% coal, and 1% biomass, was used; 8.8 tons of coarse ground eucalyptus were used for a test of 8.5 hours. Ground eucalyptus was blended with the normal coal and petcoke mixture to form a slurry that was fed to gasifier. Emissions from the power station did not increase. No plugging or other technical problems were detected in the gasifier. However the use of higher biomass blending has yet to be demonstrated at large scale.
- in a project by INETI (Portugal) and Univ. Politecnica de Catalunya (Spain), fluidized-bed co-gasification of residual biomass and poor coal blends for fuel gas production was tested at pilot scale. The effects of experimental conditions: temperature, gasification medium and blending fraction were analyzed^{60 61}

Based on the limited evidence available, an approximate picture can thus be constructed of the key reactions and mechanisms in a co-gasification process. Note that most studies have been run at CFB conditions and may not apply fully to entrained flow conditions.

In co-gasification, the solid fuels in the blend are believed to be pyrolyzed in parallel, essentially without interaction, and at different temperatures. The resulting mixed charcoal then undergoes various gasification reactions with the gasifying agent. When a blended feed enters the reactor, pyrolysis gases flow up with the upward gases from the bottom, where combustion takes place and causes a complete devolatilization. At atmospheric conditions, no methanation appears at atmospheric conditions, and hydrocarbons are formed essentially from pyrolysis and volatile matter. On the contrary direct methanation reactions occur in pressurized operation conditions. For charcoal, the reaction route is analogous to that with woody biomass gasification.

When gasification is carried out at fluidized-bed operation conditions in the temperature range of 800 – 900 °C, the remaining residue from coal can hardly enter into any effective reactions with the gasifying agent, since carbon is “wrapped up” by a large proportion of ash. A further conversion of residual carbon could be achieved at higher temperature (above 1000 – 1200 °C), using oxygen/steam as gasifying agent, that is the typical conditions of modern entrained bed coal gasification processes. However, in this case, other problems have to be solved, such as feeding biomass at pressure conditions, melting of ashes, and the impact of ashes and char on high temperature gas clean-up.

Figure 23 – Generalised Process Scheme in Coal/Biomass Co-gasification

Compared to coal gasification, co-gasification of a mixture of coal and high contents of biomass lead to a syngas with lower content of hydrogen content and higher content of hydrocarbons at temperatures between 800 and 900 °C. Therefore, though the increase of temperature favours hydrocarbon further reactions and conversion into hydrogen, the temperature increase was not sufficient to compensate the increased hydrocarbon release due to the presence of biomass.

This observation following from the simplified reaction scheme is significant for understanding and controlling co-gasification processes; however it does not necessarily represent a problem. In power applications, a further reactor for tar cracking downstream from the gasifier is usually installed to improve the quality of syngas. If the aim of the process is producing hydrogen, the excess hydrocarbons in the syngas can be converted by means of a reform/shift reactor. In any case, the presence of biomass in fuel and the rise of temperature result in an increase of char conversion and of energetic efficiency.

Other parameters that have a high influence on the co-gasification process are the oxygen/fuel and oxygen/steam ratios. Increasing the Oxygen/Fuel ratio results in an increase of gas yield but a decrease of syngas heating value, with a slight improvement of energetic efficiency. The increase of Steam/Oxygen ratio favors steam reforming reactions, which result in an increase of hydrogen and carbon dioxide in the syngas.

Most of past R&D and experiments on co-gasification were carried out in fluidized bed reactors, while very little knowledge and experience is available for co-gasification in high temperature entrained flow. The extension of process research and models to this field is of primary interest for further studies, essentially for what concerns the behavior of biomass ashes and its impact on gasifier process equipments. Co-gasification of biomass together with coal represents today a potentially strategic solution for utilities, and is expected to see continued growing emphasis also in public energy policy priorities with the growing penetration of IGCC in power generation and increased emphasis on efficient and realistic options for carbon management. Notably, a greater understanding and progress on mastering the technology of co-gasification is equally critical for all applications – power, heat, industrial syngas – not only for producing hydrogen.

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Section IV – GAPS and NEEDS

IV.1. R&D needs

Area 1. Feedstock availability, logistics and processing

- Clarification, catalogisation and characterisation (CCC) of primary biomass resources
- Mapping of variability criteria and limits in each particular geographic region
- A system of quality control for feedstock management
- Development and standardisation of pyrolysis oils and processes
- Characterisation and QA procedures for pyrolysis liquids
- Transport standardisation & shipping classifications
- Biomass intermediates as globally traded resources
- Alternative densification methods: torrefaction, others?

Area 2. Co-gasification

- Feeding systems
- Feedstock pre-treatment: size reduction, mixing/homogenization of fuels, compaction
- Processing & control parameters as function of type, amount, preparation of biomass
- Reactivity and emission characteristics of mixed fuels: burnout rates, H₂S, HCl, dioxins, alkali vapours...
- Purification of the producer gas, catalytic upgrading, effect to catalyst performance.
- Ash processing: Deposition, agglomeration, sintering, corrosion and erosion

Area 3. Ash from co-gasification

The combined gasification (real co-gasification) of biomass and coal is an attractive business option, since it brings synergy benefits, economies of scale and increases the supply base. However, co-gasification has also some potential disadvantages. Besides the risk of adverse impact on process equipment due to different properties of coal and biomass, the difficulty of using mixed biomass-coal ashes is another issue. Coal ashes find application in the building industry, employed as a concrete additive. Pure biomass ashes can be used as soil improvers (with the addition of some nitrogen fertiliser) – however, volumes of biomass ashes produced are about one percent of those in industrial gasification, so no comparable attention has been paid to biomass ash management yet. Another advantage of biomass ash is that it contains alkali substances (owing to the biomass composition), which prevents soil acidification.

It is not clear that mixed biomass-coal ash can be used either in building industry. The alkali compounds in biomass can have a negative impact on concrete properties if leachable (slag normally encapsulates many elements otherwise in the ashes). They may react to flintstone particles in the gravel with which cement is mixed during concrete preparation. This may result in absorption of water from the surroundings, leading to volume expansion, crack formations, triggered by freezing and thawing. The chlorine content of biomass is also problematic because it may cause corrosion of concrete reinforcement bars.

Hence, in the worst possible case mixed coal-biomass ash can only be dumped in a landfill. Apart from the direct adverse consequences from the landfill deposition, secondary penalties in terms of additional energy expenditure, emissions and costs are incurred by the substituting production of fertilisers and concrete additives.

Experience from co-firing includes management of mixed ashes. This should be mobilised.

IV.2. Non-technical barriers

Ownership and business structures are different in industrial gasification and biomass growing. This causes challenges to the efficient organisation of co-gasification on a broad basis.

IV.3. Possible policy measures

Recognition of benefits of co-gasifying biomass with fossil fuel – “green credits”

CO₂ cost inclusion in fossil routes of hydrogen production (if all H₂ fuel is in the transition time free of conventional fuel taxes, fossil derived H₂ could be taxed with a percentage in proportion to the CO₂ emissions caused (e.g. 10 € per ton CO₂ emitted, which would correspond to 20 – 50% of the pre-tax value compared to 150 – 300% for petrol in most EU countries). Renewable H₂ including that from biomass should be completely exempted of all tax, until H₂ has achieved a competitive position in the fuels market (at some multiple of today’s H₂ production, or at some FCV and stationary H₂ energy consumption market share)

Legislation or regulations on mixed ashes management is a key enabling issue that must be addressed at the appropriate level in parallel with the technology development.

IV.4. – Recommended IEA activities

A new IEA Task on Hydrogen from Biomass should be defined and could focus on near-market routes to hydrogen using biomass as a renewable energy source. Its main objective could be to advance the development of hydrogen production in the market and devoting most its attention on opportunities of interest for industrial application.

Specific objectives could be to

- Identify and evaluate feasible processes for co-gasification of biomass together with fossil fuels, e.g. coal;
- Quantify the potential for hydrogen supply and market building in a “combined/split” scenario of pre-processing the biomass resource by distributed pyrolysis, and using the resultant tradable intermediates as fuel in centralised (co-) gasification plants;
- Develop and verify a Roadmap for the market introduction of routes to hydrogen incorporating the use of biomass within an industrial context.

Each of these objectives could form the basis for Subtasks of the proposed new IEA-HIA Annex. A draft Work program is in preparation.

NOTE for Draft version of this report: Please refer to updated working document on suggested new Task for current status of the proposed content. Available from Task 16 Operating agent or IEA-HIA secretariat

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