IEA – HIA

TASK 16: HYDROGEN FROM CARBON-CONTAINING MATERIALS

By Advanced Thermal Processes Designed for Minimal CO_2 Emissions

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CONTENT

1 INTRODUCTION

The versatility of using hydrogen as an energy carrier stems from the fact that it can be produced from nearly any energy source – fossil resources as coal and natural gas, and renewable resources as biomass, water, sunlight and wind. A variety of process technologies can be used, including thermochemical, biological, electrolytic and photolytic.

Each technology is in a different stage of development, and each offers unique opportunities, benefits and challenges. Production can be based on an indirect route, typically using electricity as a secondary energy carrier, or using a direct route based on conversion of fossil fuels or biomass.

Task 16 concerns direct production routes for hydrogen, envisaged for the near and medium term, based on carbon containing materials.

The conventional processes convert carbon to CO_2 and causes emission to the atmosphere. Improved production technology, optimised for minimum CO_2-emissions should be developed. Decarbonisation of fossil fuels, i.e. hydrogen production coupled to CO_2 sequestration and use of hydrogen as a fuel and energy carrier will enable global reductions of CO_2 emissions to the atmosphere.

Capture and sequestration of CO_2 will be economically viable only in large-scale hydrogen production plants, thus requiring a large market demand. However, there is increasing interest in small to medium scale distributed hydrogen production, both for use as a fuel in the transport sector and for distributed CHP generation, and technology is developing rapidly. Water electrolysis may be competitive and environmentally preferable in some areas but there is probably a large potential market for small/intermediate scale reformers for production of hydrogen from different hydrocarbons like natural gas.

Hydrogen production from biomass is considered to be CO_2-neutral, and could even provide for CO_2 mitigation if coupled to sequestration. Biomass resources are significant; the potential contribution of bioenergy to global primary energy in 2050 is generally considered to be more than 15 %. The feedstock will vary greatly in composition. Hence, a key challenge is to develop conversion technologies that can deal with the range of opportunities that are available.

2 OBJECTIVE

The overall objective of Task 16 has been to promote the development of economically viable and environmentally acceptable processes for hydrogen production by thermal processing of carbon-containing materials.

Three specific objectives have been identified, forming the basis for three subtasks:

- Today, more than 60 % of hydrogen production is based on reforming of natural gas. In the future, decarbonisation is needed to meet sustainability requirements for large-scale hydrogen production and supply to the energy markets. A key challenge is the high cost of decarbonisation. Optimisation of the most attractive process concepts, coupled with a higher level of engineering definition and innovative cost minimisation, offers the promise of further improvement in the economics of this route. The objective of **Subtask A** has been to investigate the potential for cost reduction through modularisation and standardisation of proven plant components, minimising the cost of CO_2 capture.

- Production from biomass represents another large-scale route for hydrogen supply to the energy markets, with the added advantage of being a renewable energy source with a different supply structure. The feedstock alternatives and process technologies for converting biomass to hydrogen are numerous and mainly on a developmental stage. The overall objective of **subtask B** has been to stimulate and accelerate research and development of hydrogen from biomass, however, with a more specific objective of assessing and evaluating feasible supply routes in terms of markets, technology and applications.

- It is expected that distributed production will be the preferred option for hydrogen supply in the near to medium term, until markets become sufficiently large to warrant large-scale production. There are currently about 20 hydrogen-fuelling stations in operation around the world based on on-site hydrogen reformers, in addition to on-going tests of combined heat and power plants based on small reformers with PEM fuel cells. The objective of **subtask C** has been to further promote and optimise the use of small-scale, efficient reformers for distributed hydrogen production, with a focus on supplying hydrogen as a transportation fuel.

3 APPROACH

The three subtasks deals with different hydrogen supply routes in terms of production scales, process technologies and technology maturity, as well as the likely timing of its commercial applications.

The challenges and therefore the approach used to deal with the main issues of the three subtasks have thus also been different. The work in subtask A involves a fully industrial approach to cost reduction aspects of a selected, well defined process route. Subtask B, dealing with a topic (i.e. bioenergy) that is also the focus of extensive technological research worldwide, has elected to build upon current research results and know-how, summarising the technology status relevant for hydrogen production and evaluating the prospects for biomass to hydrogen routes in terms of markets and applications perspectives. The work in subtask C, dealing with near-commercial solutions for small-scale hydrogen supply, is characterized by benchmarking among knowledgeable suppliers and stakeholders for system solutions meeting customer requirements.

4 SUMMARY

There is limited benefit in trying to summarize the results of the three subtasks as such, but a few observations on the market and application aspects of the supply routes for hydrogen dealt with in the three subtasks are worth considering.

- Subtask A – Large-scale integrated hydrogen production with precombustion decarbonisation: This process route necessitates a large market demand. Furthermore, the process involves CO_2 deposition and requires construction of new infrastructure for hydrogen transmission and distribution and CO_2-pipeline to storage. The development may benefit from a transitional approach, considering co-production of hydrogen and power. Further work on this is being undertaken by the IEA GHG R&D Programme.

- Subtask B – Hydrogen from Biomass: This is another large-scale route to hydrogen, however based on renewable energy sources and as such considered CO_2 neutral. The large scale aspect of its potential commercialisation poses two challenges: that of a large market demand and the logistics for collecting biomass to the preferred processing technology. Again, a transitional approach may be beneficial, considering co-gasification with fossil fuels, and on the logistics side – solutions involving distributed processing to a secondary energy resource resulting in a "biomass carrier" may facilitate the uptake of large biomass based feedstock, for further central processing to hydrogen or syngas. These issues are the topics of a follow-up new Task proposed for HIA.

- Subtask C – Small-scale reformers for distributed hydrogen production: During the last few years, significant progress has been achieved, and several plants are now in operation. Still, commercialisation has not been reached and challenges linked to technology, incomplete systems solutions and difficult operability of fuelling stations require further research and development effort. In order to meet the long term cost targets (e.g. non taxed gasoline) the plant cost must be reduced by a factor of 2,5 – 3. System integration and system simplification are needed to close the gap to industrialisation. Therefore subtask C members recommend a further international work-group on these issues.

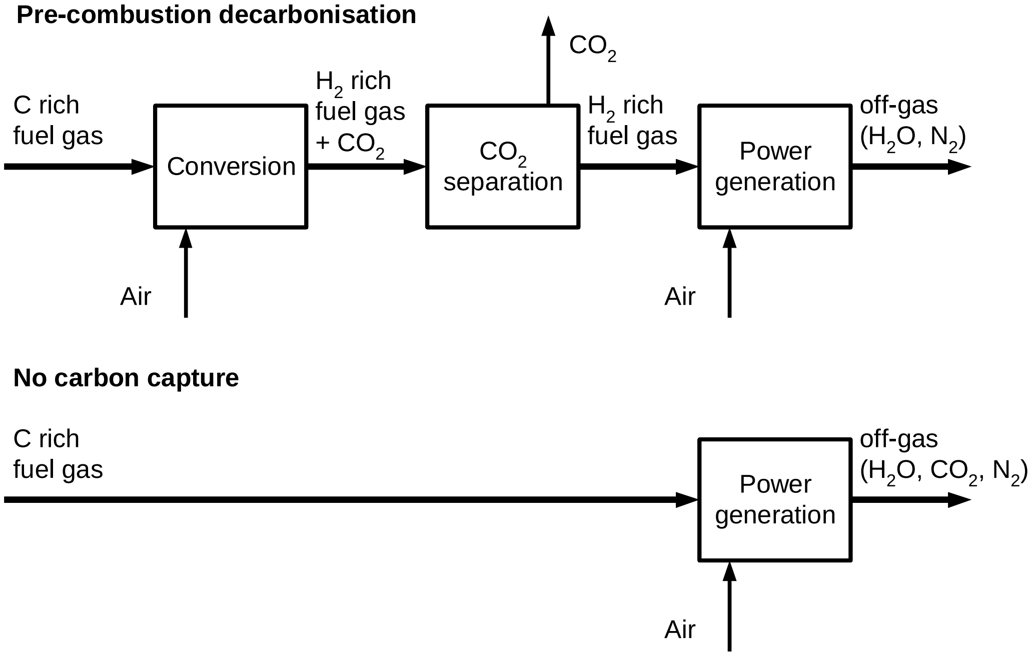
Local availability of feedstock, market applications and demand, policy issues and costs will influence the further development of the supply routes represented in the three subtasks. These issues will differ from one country or region to another, and the relevance of one or the other carbon-based pathway described in this report may well differ for the various member countries of IEA, depending on the weighting of the above issues.

5 SUBTASKS – SUMMARY AND HIGHLIGHTS

5.1 Subtask A Large-scale Integrated Hydrogen Production / Decarbonisation – Cost reduction through modularisation and standardisation

The work in Subtask A is focused on the concept of Precombustion Decarbonisation (PCDC) for power generation. Such a plant would be based on pre-combustion removal of CO_2 and would thus essentially consist of a hydrogen plant integrated with a Combined Cycle Gas Turbine (CCGT).

Fig. 4.1-1: Comparison of pre-combustion decarbonisation scheme for power production with baseline case without carbon capture



Pre-combustion decarbonisation has the potential to achieve deep CO_2 reductions using proven hydrogen production technology. The aim of the work described in this report has been to investigate the potential cost reduction of power generation from natural gas with pre-combustion decarbonisation through modularisation and standardisation of proven plant components. The task was divided into two main stages:

1. **Techno-economic comparison** of different process schemes for natural gas fired power stations using pre-combustion with CO_2 separation technology. The results from this comparison were used to select a process scheme for a detailed engineering study in stage 2.
2. **Detailed engineering study** of process scheme selected in stage 1. The study basis is a standard combined cycle unit (400 MWe) that can accommodate in a later phase or in a revamp situation the carbon free fuel

gas. The study compares performance and costs of the natural gas based unit and the standardised PCDC power plants. In order to estimate potential cost savings due to modularisation and standardisation assumptions about the expected number of identical units had to be made. This was done by analysing a number of market scenarios based on a database of fossil-fuelled power plants in different regions of the world.

A review of several studies investigating the techno-economic potential of different process schemes for power production from natural gas was performed. The comparison study focused on process schemes with pre-combustion decarbonisation using well-known hydrogen production technology, comparing the result of the individual studies available (as of 2002) on a common technical and economic basis.

Some of the studies reviewed in stage 1 analysed various process options for producing a hydrogen rich fuel gas for combustion in a gas turbine such as conventional steam reforming, auto-thermal reforming, and reaction in a gas heated reformer. However, all studies investigated concluded that auto-thermal reforming (ATR) was the reactor option that provided the best combination of cost effectiveness, technology maturity, and integration with the natural gas combined cycle (NGCC) plant.

The ATR process schemes analysed by the different studies differ mainly in the
- Degree of heat integration
- Amount of air extracted from main air compressor
- Fuel gas temperature gas turbine
- Fraction of natural gas bypassing decarbonisation plant
- ATR preheating options

The review indicates that CO_2 capture cost for the most favourable cases amounts to approximately 25 USD/tCO_2 at electric efficiencies between 43 and 49% compared to 56% of the reference case without CO_2 separation. The costs per avoided ton of CO_2 emission compared to the reference case were in the range 30 to 40 USD/t with additional investment costs of 250-350 USD/kW installed electric power. Depending on the process scheme employed the CO_2 capture rate was between 77 and 88%.

Based on the analysis of the study reports available, the recommended PCDC process scheme should contain the following main process steps:

- Desulphurisation unit
- Preheating of feed streams in fired heater
- Air blown ATR
- High pressure steam production downstream of ATR
- HT and LT shift configuration
- Two-step aMDEA system with HP/LP-flash and stripper
- Either steam addition or saturation to gas turbine
- Fuel composition – approx. 50/50 H_2/N_2 (dry basis) with 15-20% water
- Nitrogen content to be determined by maximum air extraction
- Minimum heat integration with gas turbine HRSG

Based on the finding from the PCDC technology review summarised above an engineering study was initiated and financed on a cost-sharing basis by the CCP consortium[1]. Jacobs Consultancy[2], part of the international Jacobs Engineering Group, has been selected to execute this study.

The engineering study contains a detailed engineering study of a complete natural gas fired power plant including a PCDC plant based on air-blown autothermal reforming. The study covers integration aspects, investigates the cost reduction potential through standardization and repeat manufacturing, and provides a detailed economic analysis including a sensitivity analysis for gas price and availability. In addition, a market study has been performed to estimate the size of the market for gas-fired power stations with CO_2 capture for the period 2005 to 2025. Potential savings through standardization are obtained by comparing cost of a repetitive design with a 'first of a kind' reference plant based on modified standard components.

Firstly, a state of the art proven technology 400 MW natural gas power plant without CO_2 separation was chosen as a reference. The combined cycle power plant comprises:

- A gas turbine
- A triple pressure non-fired natural circulation heat recovery steam generator (HRSG) with reheat
- A steam turbine with a HP, IP, and LP condensing section

The standard reference plant without CO_2 capture provides an electrical power output of 392.2 MW at a net fuel efficiency of 55.9%.

Secondly, a reference fuel plant was designed to produce a hydrogen rich fuel gas by autothermal reforming and CO_2 separation. The fuel plant consists of

- A reforming stage converting a mixture of natural gas, steam and air is converted to a mixture of H_2, CO, CO_2, and N_2
- Two stage shift reactor converting CO and steam to CO_2 and H_2 followed by H2O separation
- CO_2 removal using a chemical solvent
- CO_2 compression to 110 bar and liquefaction using a six stage compressor with intermediate water removal

After integration of the combined cycle with the fuel plant the PCDC power plant provides 364.8 MW at a total electric efficiency of 41.3%.

The market study is based on a global annual yearly capacity installed of some 42 GW_e of which 50% is natural gas based.

Assuming a 10% market share in the gas-fired units to use the PCDC concept, this results in a market growing from 2000 MW_e or 5 units per year in the early part of this century growing to 4000 MW_e or 10 units per year around 2020.

Savings due to modularisation have been achieved by packaging equipment and pipes into rack-mounted pre-fabricated units that can be loaded on a truck and assembled on site. Main savings are achieved by moving construction work to a more controlled manufacturing shop environment, thereby increasing labour productivity. This allows a larger fraction of the manufacturing process to be moved to geographic areas where productivity is high. Additional productivity improvement and higher quality can be achieved by the use of consistent, dedicated workforce if a number of standardized units are produced in series. The requirement of additional steel for rack construction and higher transport costs offset some of the savings achievable by reducing labour cost. In total, labour cost savings in the range 5-15% seem achievable depending on the geographical region selected for workshop manufacturing.

Standardizing a modular design can eliminate some of the repeat design costs on subsequent units. It was assumed that through standardization cost reductions of 75% for engineering, 40% for procurement, 20% for construction, and 12% for equipment and material could be achieved.

As a result of modularisation and standardization the capital expenditure of a 400 MWe PCDC plant drops from 392 M$ for the first unit to 351 M$ for unit 10 compared to a standard natural gas combined cycle power station at 181 M$. The resulting avoided CO_2 cost drop from 68.4 $/t for unit 1 to 55.5 $/t for unit 10 – a 19% decrease through repeat manufacturing.

Although significant savings have been identified by modularisation and standardization, the investment cost estimate for a standardized PCDC plant calculated by Jacobs is still more than 10% higher than estimates by previous studies. The cost difference can at least partly be explained by the fact that Jacobs are operating with very high costs for CO_2 and air compressors, which together account for more than 30% of the total investment costs.

In conclusion, it can be said that natural gas fired power production with CO_2 capture results in significant increase in investment and operating cost compared to a conventional natural gas combined cycle unit. The use of fossil fuel will increase significantly due to the reduced overall efficiency:

Standardization can reduce the total investment cost by 10% and the avoided CO_2 cost by nearly 20% compared to the first plant to be built:

<u>Recommendations for further work</u>

Some focus areas for further process optimisation are:

- Optimum CO_2 capture efficiency
- Revamp option potential, say new CO_2 capture technology *e.g*. Sorption Enhanced WGS
- Optimum process parameters, *e.g.* steam/carbon ratio

For future work emphasis should be put on bringing cost down for rotating equipment. According to Jacobs study 50-60 % of capital cost for PCDC originates from compressors and steam turbines.

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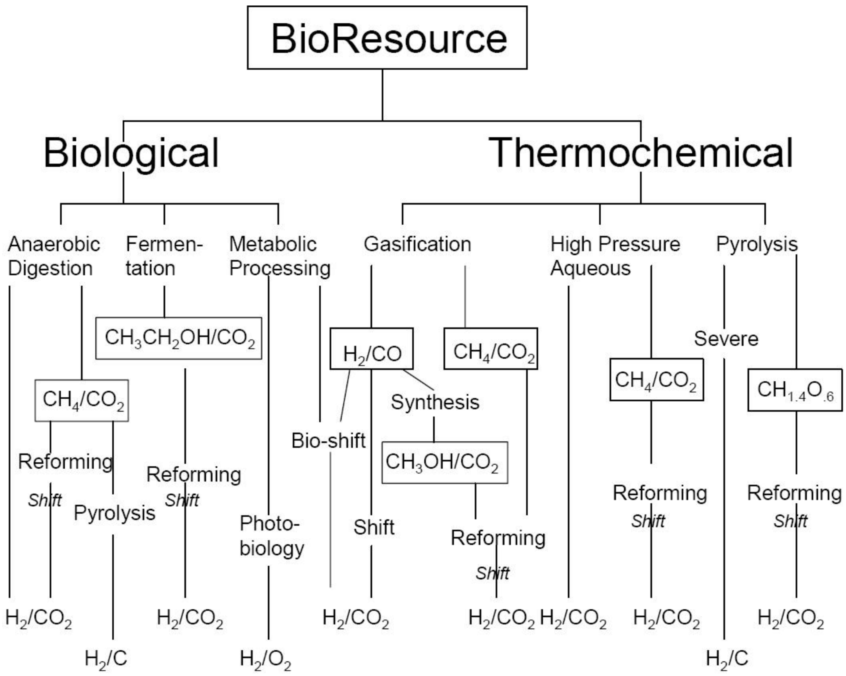
1 The CCP (CO2 Capture Project) is an international effort of eight of the world's leading energy companies namely BP, Chevron Texaco, ENI, Hydro, EnCana, Shell, Statoil, and Suncor Energy to develop new low-cost technology options for the CO2 capture and storage.

2 Jacobs Consultancy is a widely recognised independent consultancy company with significant experience as an independent engineer for financial institutions and in benchmarking of energy and carbon emissions reduction programs on behalf of European government agencies, energy and utility companies.

5.2 Subtask B: Hydrogen from biomass

There are several pathways for biomass to hydrogen, and to a large extent shared for a number of alternative end-products. Technologies for converting biomass to useful energy products are extensively covered by experts in the field, e.g. the IEA Bioenergy Implementing Agreement. While the work currently done on biomass to hydrogen conversion has been to a large extent technological, the approach of the subtask B group has been basically pragmatic, trying to adopt an industry view based in markets – current and future – and practicable industrial processes. The overall aim has been to identify 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.

Fig.: 4.2-1: Pathways from biomass to hydrogen – excerpted from Milne et al. 2002 [i]
Boxes indicate storable intermediates



Below are summarised the main findings and conclusions from subtask B:

- Biomass is the only near term pathway to hydrogen from renewable energy sources (RES) that can be implemented without a need for any major R&D breakthrougs, and without resorting to the use of electricity already generated from renewable sources.

- 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.

- 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.

- Thermochemical routes for biomass gasification and processing the resulting synthesis gas to H_2, 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.

- Biomass-derived hydrogen is capable of addressing any current and future H_2 market. Produced by thermochemical routes via syngas, biomass-derived hydrogen can yield H_2 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 H_2 from biomass in the next generation of PEM fuel-cell vehicles, which are widely expected to reach the market in 10 to 15 years.

- 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 CO_2. Cogasification 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.

The report follows these main findings by identifying scaling as the major problem in achieving an efficient value chain and thus process. The dispersed nature of biomass calls for small scale, whereas fuel production is a classic economy of scale business. Based on recent attempts to combine densification of biomass and co-gasification with fossil fuels, a possible pathway is sketched whereby dual front-to-back scaling can be done.

Finally the report notes that many elements of the value chain and technology are shared with the production of liquid biofuels. Their current strong market pull could be mutually beneficial and help with timing and growing volume for biomass to hydrogen. Many 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.

Recommendations for further work

It is recommended that a new IEA Task on Hydrogen from Biomass is 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 of 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 one of three Subtasks of the proposed new IEA-HIA Annex. A draft work program is in preparation; the draft is presented in Enclosure 6.2.2.

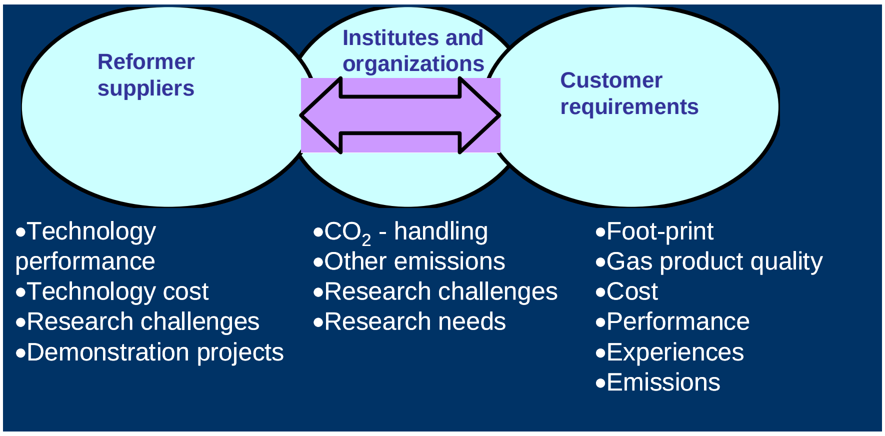
5.3 Subtask C: Small stationary reformers for distributed hydrogen production

At early stages of a hydrogen economy, the demand for hydrogen will be for small volumes and geographically decentralised. Small production units can be modular, scalable and can provide hydrogen where needed, allowing supply to match demand.

Small-scale reformers are commercially available from several vendors who are targeting the conventional industrial gas market. Few of them are presently aiming at the hydrogen refuelling station market. Newcomers are developing small-scale reformers for integration with fuel cells. The aim is for electricity production and distributed Combined Heat and Power (CHP) markets. Most of these fuel cells are based on the Proton Exchange Membrane (PEMFC).

The objective of Subtask C has been to define system solutions for early markets by evaluating the reformer technology from two angles, the market requirements and the technology performance. The methodology was based on present commercial and research activities of the members, which included participants from reformer supplier companies, potential customers and institutes and organisations.

Fig. 4.3-1: Participants/roles and tasks



Focus has been on commercial and pre-commercial small-scale reforming technology (time frame of 5-10 years), rather than on future technologies that are presently basic research and might become commercial in the long term (beyond 20 years).

The technology providers have achieved significant progress in system quality and technology performance over the last few years, as the example in figure 4.3.2 indicates. Market survey shows that the gap between customer requirements and technology performance can be overcome.

Fig. 4.3-2: Development of compact reformers[1]

The results of the subtask C analysis on how the technology can meet the market requirements are summarised in Enclosure 5.2. CO_2-handling and emission performance as well as the use of the technology for providing hydrogen to integrated combined heat and power plants are also reported.

The highlights are:

- Small - scale reformers for on-site hydrogen production are presently (2005) competitive with on-site electrolysis, and in some regions are even competitive with trucked in hydrogen
- The short - term customer priorities include costs, footprint, reliability, durability and hydrogen gas quality
- CO_2- performance of the small-scale reformer is good, however, CO_2 - capture is not feasible with current costs and technologies.
- Exhaust emissions are marginal and within acceptable urban limits
- System integration and design simplification are needed in order to shorten the gap to commercialisation
- Companies involved in reformer development are not in the mass-production phase, and the gap between the current technology and a future commercial product is still large. Mass production of reformers will require substantial reduction in the number of components and system complexity. Identification of strategies to overcome the gaps is of high importance. Proprietary issues have to be addressed in order to secure the commercial interest of the participants.

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[1] Osaka Gas data

- In order to meet the long term cost targets (e.g. non taxed gasoline) the plant cost must be reduced by a factor of 2.5 – 3. The potential cost-reduction for the auxiliaries is 70 %, and according to Osaka Gas, the potential for cost-reduction for the complete plant is 20 – 30 %. A comprehensive cost-reduction study could be made by an independent research institute in order to assess these statements, particularly in terms of cost reduction induced by a mass production.

- Hydrogen price, based on the Osaka Gas technology, is close to the taxed Japanese gasoline (with 50% tax). Moreover, competitiveness with trucked-in hydrogen is already achieved, and the number of hydrogen trailers may decrease. Benchmarking with conventional fuels, and with alternative and competing technologies, could be a useful tool to define and update targets for the reformer technology as the hydrogen fuel market develops.

- A procedure for learning from demo-projects should be established. A common monitoring program can be built, and collected data can be checked against present and future standards on product quality, safety, defects and incidents.

The reformer technology is a potential on-site production option for the new hydrogen market. The results presented in this report show that the small-scale reformer technology is likely to become competitive on cost, footprint and operability. However, experience data are still limited and few references can be made to modern large-scale plants in operation.

Recommendations for further work

The subtask C members have recommended continuing the work in a new Task. A new IEA HIA Task is proposed on the development of reformer technologies and distributed on-site hydrogen supply systems based on reforming.

A draft work-program has been developed on the basis of the results and recommendations from the present Task 16 – subtask C (Enclosure 6.2.1).

6 ENCLOSURES

6.1 Final subtask reports

6.1.1 Subtask A report: Large-scale Integrated Hydrogen Production for Power Generation/ Precombustion Decarbonisation

6.1.2 Subtask B report: Prospects for Hydrogen from Biomass

6.1.3 Subtask C report: Small-scale Reformers for Stationary Hydrogen Production with Minimum CO2-emissions

6.2 Proposals for new tasks

6.2.1 Proposal for new Task: Small-scale reformers for on-site hydrogen supply

6.2.2 Proposal for new Task: Near-market routes to hydrogen using biomass as a renewable energy source

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[i] Milne, T.A., Elam, C.C. & Evans, R.J. (2002) "Hydrogen from biomass. State of the art and research challenges. (A Report for the International Energy Agency Agreement on the Production and Utilisation of Hydrogen Task 16, Hydrogen from Carbon-Containing Materials)", National Renewable Energy Laboratory (NREL), Golden, CO, USA, Report IEA/H2/TR-02/001