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U.S. Department of Energy – Hydrogen from Natural Gas and Coal: The Road to a Sustainable Energy Future

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Office of Fossil Energy - Hydrogen Program Plan

Hydrogen from Natural Gas and Coal: The Road to a Sustainable Energy Future

Hydrogen Coordination Group

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EXECUTIVE SUMMARY

The President's National Energy Policy calls for conducting a review of funding for alternative energy supplies, including hydrogen. In response, the Office of Fossil Energy (FE) established a Hydrogen Coordination Group to develop the FE Hydrogen Program Plan. The coordination group was comprised of FE personnel from the Offices of Coal & Power Systems and Natural Gas & Petroleum Technology in Germantown, MD and Washington, DC and the NETL Pittsburgh and Tulsa offices. The FE Hydrogen Program Plan, along with input from the Offices of Energy Efficiency and Renewable Energy, Nuclear, and Science and the two documents – *A National Vision of America's Transition to a Hydrogen Economy – to 2030 and Beyond* and the *National Hydrogen Energy Roadmap* – provided the input to the Department of Energy's (DOE) Hydrogen Posture Plan. The Posture Plan, with the Office of Energy Efficiency and Renewable Energy (EERE) as lead, was DOE's response to the NEP recommendations, which was used to support DOE's FY04 budget to Congress.

Hydrogen is seen by many as the energy carrier of the future that will lead to efficient and clean fuel for use by utilities and especially in transportation systems. The use of hydrogen in fuel cells to electrochemically produce electricity and for combustion in heating and/or engine systems is seen as a means to provide an important part of the Nation's need for power, heat, and transportation while achieving very low emissions of criteria pollutants as well as greenhouse gases.

This FE Hydrogen Program Plan focuses on the research, development and demonstration (RD&D) activities that are required to develop advanced hydrogen production, storage and delivery technologies from fossil fuels. The result of these activities will improve current technology and make available new, innovative technology that can produce and deliver affordable hydrogen from natural gas and coal with significantly reduced or near-zero emissions.

Natural gas and coal have the potential to be affordable resources that can produce the large amounts of hydrogen needed in the near to mid term for the Nation to begin the transition to a hydrogen economy. Hydrogen produced from these resources and used in advanced technologies, especially in efficient fuel cell vehicles (FCVs), will improve energy security by reducing the United States' oil imports by over 3 million barrels per day for every 100 million FCVs or nearly half of the U.S. fleet. Even without sequestration, production and use of coal-derived hydrogen in 100 million FCVs is estimated to also reduce carbon dioxide, a greenhouse gas (GHG), by 278 million tons per year, a reduction of 24 percent of the carbon dioxide emissions associated with the current U.S. light-duty vehicle fleet. Nitrogen oxide (NOx) emissions will be reduced by about 100,000 tons per year, while sulfur oxides (SOx) and particulate matter emissions would be reduced by 43 thousand tons and 40 thousand tons, respectively. Criteria pollutants and carbon dioxide emissions would be reduced by about the same or a greater amount for natural gas-derived hydrogen in FCVs.

When hydrogen production from fossil fuels is combined with carbon sequestration, carbon dioxide emissions will be reduced by over 530 million tons per year for each 100 million FCVs, a reduction of 45 percent for the current U.S. light-duty vehicle fleet. Also, the use of the Nation's domestic natural gas, its huge potential resource of methane hydrates (estimated at 320,000 trillion cubic feet), and 250-year supply of coal to produce hydrogen ensures that there will be a clean and affordable alternative to imported oil. This will enable the transition to a hydrogen economy until other sustainable energy resources for hydrogen production become economic.

Where do we get hydrogen?

Molecular hydrogen does not occur on Earth but must be produced from other hydrogen-containing materials. This process requires a primary energy source, such as fossil fuels, nuclear, or renewables. Fossil fuels (e.g., natural gas and coal) as that energy source can provide the transition to a hydrogen economy by delivering a near- to mid-term source of hydrogen. With sequestration, it is envisioned that natural gas and coal could be used to produce hydrogen for many decades. A sustainable hydrogen supply in the future may come from renewables and nuclear energy-supplied heat and electricity used to split water into hydrogen and oxygen.

Need for hydrogen research

While some hydrogen production technologies are commercial now and others are making rapid progress, hydrogen faces many technical, economic, and infrastructure challenges before it can become a significant energy carrier. The Bush Administration has initiated major efforts in research and development that will lead to a hydrogen economy. The President's budget calls for increases in funding for hydrogen-related research, development and demonstration (RD&D) activities, with a shift in emphasis to higher risk, longer term issues. This includes, for example, the FreedomCAR program, the FutureGen project, and the Hydrogen Fuel Initiative.

The FreedomCAR program is focused on the development of fuel cell technology for automobiles to efficiently convert hydrogen's electrochemical energy into electric power. Hydrogen fuel cell vehicles consume only one-third the energy of a current gasoline internal combustion engine per mile driven while achieving zero emissions. Natural gas and coal can provide the most affordable source of abundant hydrogen to allow early introduction of fuel cell vehicles in the FreedomCAR program and can continue to provide hydrogen as an energy carrier until hydrogen from renewable and nuclear energy becomes affordable. In this way, the Nation's imports of petroleum can be reduced and our air and environment can become cleaner.

FutureGen is a $1 billion, 10-year verification project that will build the world's first, coal-based, near zero-emission electricity and hydrogen plant integrated with sequestration. FutureGen will enable cutting-edge technologies, such as revolutionary separation membranes, to leapfrog mature technologies to lower the cost to separate hydrogen from mixed gas streams while demonstrating greenhouse gas capture and sequestration technologies.

The long-term vision of a hydrogen economy looks attractive for a number of reasons including: (1) the gradual transformation of the U.S. economy from one that currently relies on significant quantities of imported energy, primarily oil for the transportation sector, to one that will be able to harness domestic resources to a greater and greater extent, while being less damaging to the environment; (2) the potential for significant reductions in criteria pollutants (e.g., particulate matter, oxides of nitrogen, and oxides of sulfur) and corresponding improvements in air quality; and (3) the potential for reduced emission of greenhouse gases, especially carbon dioxide.

Fossil Fuel Research

Fossil fuels are an obvious choice as energy resources from which the large quantities of hydrogen needed to begin the transition to a sustainable hydrogen economy can be produced. Currently, hydrogen for industrial and commercial use is produced from steam reforming of natural gas with attendant water-gas shift reactions. This is a mature technology widely used in the petroleum processing industry. Significant opportunities exist for development of new technologies with potential to reduce the costs of hydrogen production from natural gas. Another fossil fuel, coal, is the Nation's largest domestic energy resource, and can also be an energy source for producing hydrogen. With associated carbon dioxide capture and sequestration technologies, hydrogen from natural gas and coal can make significant contributions toward achieving an improved environment.

Hydrogen from Natural Gas Program

This program will develop new technologies that lower the cost of producing hydrogen from natural gas and allow capture of associated carbon dioxide. In keeping with the National Energy Policy and relevant climate change initiatives, research will develop those technologies that will provide a primary source of hydrogen in the near to mid term, allowing development of infrastructure and end-use applications that will transition the Nation to a sustainable hydrogen economy. One technology, membrane reactors, will revolutionize the way hydrogen is produced from natural gas. When developed, this technology will simplify the process of producing hydrogen from natural gas by combining the process of air separation to produce oxygen with partial oxidation of natural gas to produce synthesis gas into a single step that will lower costs and increase efficiencies.

Hydrogen from Coal Program

Coal resources offer a viable mid-term energy resource for producing the large quantities of hydrogen that will be required to fuel the Nation's needs. Initially, hydrogen would be produced via coal gasification-based facilities also capable of co-producing electric power, reformable liquid fuels, and high-value chemicals. These multiple-product, co-production plants will be less costly, competitive, more efficient, and less polluting than current technology. Additionally, they will produce a concentrated stream of carbon dioxide that will facilitate its economic capture and sequestration.

To accelerate the development of hydrogen from coal production technologies, President George W. Bush and Secretary of Energy Spencer Abraham announced on February 27, 2003, a $1 billion, 10-year government/industry integrated sequestration and hydrogen research initiative titled

FutureGen. FutureGen would be designed, built, and operated as a large-scale, prototype plant that will serve as an engineering verification test-bed for many cutting-edge coal technologies, including technologies such as advanced catalysts and reactors and membrane separation units developed in the hydrogen from coal program. The prototype plant will become a model for future hydrogen from coal production facilities that will produce the necessary amount of hydrogen for the transportation sector.

Commonalities and Differences

There appears to be much similarity in the technology and processing concepts used to produce hydrogen from natural gas or hydrogen from coal, and indeed there is a need for coordination in the effort to develop the respective technologies.

At the same time, there are significant system differences in these concepts that make R&D planning and implementation more effective on a resource-specific basis. A synthesis gas mixture from coal is carbon monoxide-rich and the synthesis gas mixture from natural gas is hydrogen-rich, making it necessary to explore whether the same production/separation membranes will be effective. Coal-derived synthesis gases, even after a primary clean-up stage, have more impurities than their natural gas counterparts that may require different clean-up systems. In addition, integration of the hydrogen separation technology into the coal gasification-based hydrogen production facility is more complex, requiring different system integration efforts.

Hydrogen Delivery

Today, most hydrogen used in refineries and chemical facilities is produced on site. In addition, merchant hydrogen producers who supply the refining and chemical industries locate generation facilities near end-users, use dedicated hydrogen pipelines and storage facilities, and, for low-volume users at greater distances from the supplier, use on-road trucks for delivery. The unique properties of hydrogen may make the use of existing natural gas delivery infrastructure difficult because of potential material and valve incompatibility resulting in hydrogen leakage and embrittlement of components. Therefore, systems analyses and research are needed to determine the viability of using natural gas pipelines to transport hydrogen. From a larger perspective, this same approach must be extended to other options to determine the most optimum system that can be used to deliver hydrogen. The analyses should consider the trade-off between large capital investments in central location hydrogen plants, associated pipelines, and delivery versus the use of liquid and natural gas infrastructure to deliver hydrogen-rich fuels that can be converted on site.

One promising option for the delivery of hydrogen uses the current fuel infrastructure to transport synthesis gas-derived liquids. At or near the point of end use, the hydrogen can be produced from the liquid by a reforming process. The technologies for producing these liquids from natural gas are commercial or near commercial. However, for the conversion of coal-derived synthesis gas to a liquid, R&D is necessary to make the process economically viable for deployment in this country. In addition, for these hydrogen-carrier liquids, whether produced from coal or natural gas, further research is needed to determine the optimum fuel(s) for reforming and the associated reaction chemistry database required to develop economic, small-scale reforming systems for mobile and small-scale distributed power generation.

Associated Programs

The successful development of low-cost, affordable hydrogen production from fossil fuels, with sequestration of carbon dioxide, is dependent on technologies being developed in a number of ongoing associated RD&D programs within the Office of Fossil Energy (FE). These technologies are needed for:

- carbon dioxide capture and sequestration;
- advanced coal gasification, including feed handling systems;
- efficient gasifier design and materials engineering;
- advanced synthesis gas clean-up technologies;
- advanced membrane separation technology to produce a lower-cost source of oxygen from air; and
- fuel cell modules that can produce electric power at coal-fired integrated gasification combined-cycle power plants.

Key Hydrogen R&D Milestones

A future hydrogen economy will require multiple energy supply sources. Natural gas and coal will provide the transition to a sustainable energy supply. The key milestones of FE's Hydrogen Program are:

- By 2011, an alternative hydrogen delivery system utilizing hydrogen-rich, synthesis gas-derived liquid fuels will be optimized and available,

- By 2013, modules to reduce the cost of hydrogen and synthesis gas production from natural gas by 25 percent will be available,

- By 2015, a zero-emission, coal-based plant that co-produces hydrogen and electric power with sequestration to reduce the cost of hydrogen by 25 percent when compared to existing coal-based technology will be demonstrated.

Testing of coal-based technologies developed by the program in the FutureGen prototype plant will significantly reduce the technical and economic risk associated with program RD&D activities, helping the FE hydrogen program achieve its key goals and milestones.

Benefits

Hydrogen from fossil fuel energy sources is an obvious near- to mid-term economic and technically feasible method to transition from fossil fuel to hydrogen as an energy carrier. Specific benefits of the Office of Fossil Energy's Hydrogen Program activities are discussed below.

- Production of lower cost hydrogen from natural gas could provide the earliest transitional source of hydrogen for the FreedomCAR program. It can provide the transition between the current economy and a hydrogen economy.
- Production of low-cost hydrogen from coal or synthesis gas-derived liquid fuels will reduce reliance on imported oil, increase the proportion of domestic energy resources used in the total domestic energy mix, and provide a cost-effective source of hydrogen for the FreedomCAR program.
- The production of hydrogen from domestic coal and natural gas along with natural gas from secure foreign energy resources and from abundant methane hydrates will be a significant step towards achieving energy security in the near term as well as the long term.
- The use of hydrogen in fuel cells and other efficient applications will reduce pollution compared to other alternatives and potentially reduce greenhouse gas emissions. This technology will improve human health and the environment.
- The hydrogen from coal technology integrates long-range R&D goals for innovative technology development of a co-production, highly efficient facility for the combined production of power and hydrogen while achieving the objectives of a zero-emissions fossil energy plant.
- Successful development and implementation of carbon dioxide sequestration technology, an R&D effort supporting the hydrogen from natural gas and coal effort, will ensure the continued availability of coal and natural gas as viable sources of hydrogen while moving toward a sustainable hydrogen economy.

Hydrogen could eventually be produced from fossil energy resources, renewables, including biomass, and nuclear energy. Analyses have shown that an aggressive fossil fuel-based hydrogen production program can yield a sufficient supply of hydrogen to meet projected market demand for fuel cell vehicles. When utilized in these vehicles, hydrogen will substantially reduce emissions of sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NOx), Volatile organic compounds (VOC), and particulate matter 10 microns in diameter (PM10). In this way, hydrogen from natural gas and coal provides a near- and mid-term transitional fuel source until the long-term goal of producing hydrogen from nuclear and renewable energy is realized. Successful development of carbon dioxide capture and sequestration technology will eliminate public concerns over projected increases of greenhouse gas emissions from fossil fuels and will make coal an option for the longer term.

In conclusion, within DOE, the Office of Fossil Energy already has considerable expertise in the production, separation, storage, delivery and end-use applications of hydrogen from natural gas and coal. This expertise includes production of clean synthesis gas from coal and natural gas, gas separations and purification, fuel cells, and novel hydrogen storage and delivery technologies. However, there are significant technical and economic barriers that must be surmounted before hydrogen can seriously be considered as a candidate energy carrier in the United States. This document discusses the rationale for using hydrogen as an energy carrier, reviews the current and future technology options, and provides a strategic framework for overcoming the current barriers to large-scale hydrogen production and utilization.

As a result of synergism in R&D activities, the currently ongoing and planned fossil energy associated programs (gasification, carbon sequestration, and fuel cells) will reduce the development time and cost of the proposed hydrogen initiative and will greatly contribute to the ultimate development of more efficient, less costly, environmentally preferred, hydrogen production and delivery processes from natural gas and coal.

INTRODUCTION

Two of the major concerns in the U.S. energy sector today are energy security and the environmental impact of energy use. To address these issues, the President's 2001 National Energy Policy and the U.S. Department of Energy's Strategic Plan call for expanding the development of new and diverse energy supplies. Hydrogen - a promising solution for the future - holds the potential to provide a virtually limitless carrier of clean energy supplies in the long term.

The U.S. Department of Energy (DOE) is implementing an initiative that could eventually lead to domestic energy sustainability for the transportation and power sectors through the widespread use of hydrogen. Hydrogen is the ultimate clean fuel with a wide range of uses - from direct combustion to efficient fuel cells. The conversion/combustion by-product of hydrogen is essentially water. An economy that uses hydrogen derived from domestic fossil (with carbon dioxide capture and sequestration), nuclear, and renewable resources will have increased energy security and reduced emissions.

To begin the implementation of the hydrogen initiative, DOE convened meetings among representatives from industry, the National Laboratories, public interest groups and the Federal Government to develop *A National Vision of America's Transition to a Hydrogen Economy – to 2030 and Beyond* and the *National Hydrogen Energy Roadmap*. These documents introduce actions that will be needed to implement a national hydrogen economy, one in which hydrogen is used for both mobile and stationary applications. Subsequently, using these documents as a guide, DOE's Offices of Energy Efficiency and Renewable Energy, Fossil Energy, Nuclear Energy and Office of Science prepared a Hydrogen Posture Plan. The Hydrogen Posture Plan encompasses all elements in the hydrogen energy system - production, delivery, storage, conversion, and application. This Office of Fossil Energy Hydrogen Program Plan includes the contributions that the Office of Fossil Energy will make in the implementation of the National Hydrogen Vision, the Roadmap, and the DOE Hydrogen Posture Plan.

Before the vision of producing hydrogen from nuclear and renewable energy becomes a reality, a technology bridge must be developed to connect near- to mid-term technology to the technologies of the future. Hydrogen is not a primary source of energy, but an energy carrier. Consequently, it must be produced from a primary energy source, such as fossil fuels, nuclear, or renewables, and subsequently converted to energy at or by the utilization device.

Fossil fuels are the obvious transitional source of hydrogen for the near and mid term. Natural gas has the lowest carbon intensity of all fossil fuels and is the cleanest burning. Its existing infrastructure and its current economic availability are important factors to ensure successful development and public acceptance of a hydrogen energy system. Development of the large potential resource of methane hydrates can provide a stable, domestic supply of natural gas that will enhance energy security. Utilization of our abundant, domestic supply of coal resources to produce hydrogen will reduce U.S. reliance on foreign imports of petroleum. When utilized in FCVs, hydrogen from fossil fuel resources will reduce emissions of greenhouse gases and criteria pollutants such as NOx, SOx, and particulate matter less than 10 microns in diameter (PM10).

Of the five elements of a hydrogen energy system - production, storage, conversion, delivery, and applications - the Office of Fossil Energy's Hydrogen Program Plan focuses on the development of advanced production, storage, and delivery technologies. These developments will be coordinated and collaborated with the Office of EERE and other appropriate DOE organizations including co-sponsorship and funding. These activities will improve current technology and develop new innovative technology that can produce, store, and deliver affordable hydrogen from natural gas and coal while achieving significantly reduced or near-zero emissions. Successful development of carbon dioxide capture and sequestration technology will remove public concern over greenhouse gas emissions and will also make coal an option for the longer term.

Testing and evaluation of these advanced technologies in the FutureGen prototype plant will help the FE Hydrogen Program reduce the technical and economic risk associated with new, innovative technology development. The FutureGen project will design, build, and operate a large-scale, integrated, coal-based prototype plant that will provide the opportunity to test new, cutting-edge, clean power and hydrogen from coal technologies along with carbon capture and sequestration.

KEY DRIVERS

The FE Hydrogen Program strives to create public benefits for the Nation by addressing three key drivers: energy security, the Clear Skies Initiative that addresses air pollution, and global climate change. Each of these drivers has or potentially could have a significant impact on the Nation and the economy. The FE Hydrogen Program will address these drivers by performing RD&D that will:

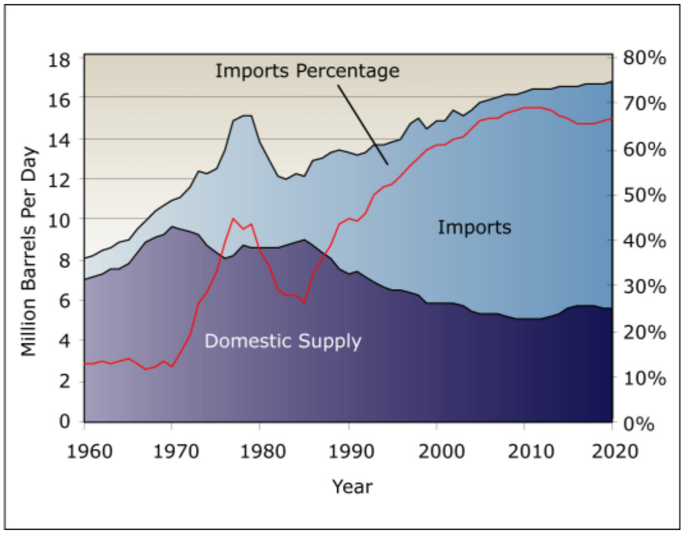
- develop advanced clean and efficient technologies that will produce hydrogen from natural gas and coal, enhancing the use of domestic energy resources;
- eliminate environmental concerns associated with the production of hydrogen from fossil fuels; and
- partner with industry to promote the commercialization of these technologies.

By developing new and innovative technology to produce hydrogen from natural gas and coal, the FE Hydrogen Program will benefit the public by enhancing U.S. energy and environmental security in a cost-effective manner through the use of domestic resources.

Energy Security

The Nation's energy consumption is directly linked to economic growth. However, the Nation's production of domestic fossil fuels, particularly petroleum, is expected to be insufficient to meet the needs of our growing economy. Therefore, a secure supply of affordable energy is critical for the continued economic growth and prosperity of the United States. Maintaining energy security in the future may be difficult because: 1) the United States is forecast to increase the volume of already large oil imports in the coming years, and 2) there is concern expressed by some analysts that world conventional oil production may peak in the next few decades before it begins a long decline.

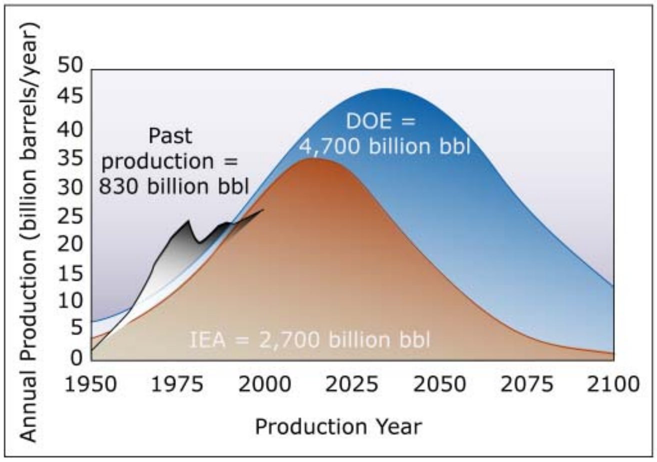
Figure 1: Historic and Projected Domestic Crude Oil Supply and Imports (1960 – 2020)



Source: EIA

Currently, the United States imports about nine million barrels per day of crude oil. Natural gas imports are increasing as well. By 2020, the Energy Information Administration (EIA) projects that imports will rise to 11 million barrels per day of crude oil, excluding petroleum products, accounting for nearly 67 percent of supply (see Figure 1). Over this period, world oil consumption is projected to rise from 76 to 119 million barrels per day. In China and India alone, consumption is expected to increase by over nine million barrels per day during this period, with a corresponding increase in imports in those countries.

Figure 2: World Conventional Oil Production.



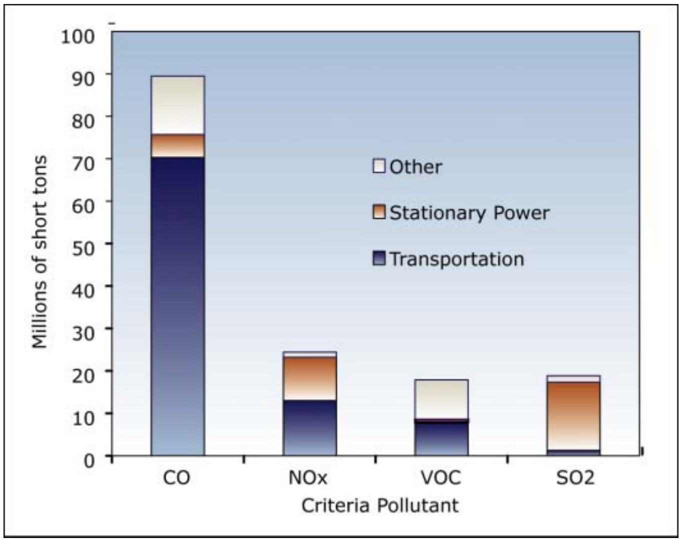
Source: J.H. Laherrere, Oil and Gas Journal, February 1999.

Conventional petroleum is a finite resource and its production will eventually peak and irreversibly decline in the face of predicted increasing demand. Some analysts estimate that the world's average ultimately recoverable conventional oil resource is 2,700 billion barrels, which implies that the peak world conventional oil production would occur around the year 2015. Even if the remaining recoverable resource of conventional oil were nearly double this estimate so that the ultimately recoverable resource was 4,700 billion barrels, the production peak would occur only about 20 years later (Figure 2). For both estimates, alternative energy resources need to be available to ensure the Nation's future energy security.

Environment

Other challenges facing energy use are the issues surrounding emissions from fossil fuel utilization (e.g., combustion, conversion), increased levels of greenhouse gases, especially carbon dioxide, and their impact on urban/regional air pollution and climate.

Figure 3: Transportation and Stationary Power Contributions to Criteria Air Pollutant Emissions



Source: ORNL, Transportation Energy Data Book, Edition 22.

Air Pollution

Of the man-made emissions, U.S. transportation and power production are responsible for over 84 percent of the carbon monoxide, 95 percent of the NOx, 48 percent of the VOCs, and over 92 percent of SO_2 emissions (Figure 3). There have been improvements in emissions, as the NEP states: "An individual car meeting 2004 Federal requirements will emit 95 percent less carbon monoxide, 94 percent fewer NOx emissions, and 98 percent fewer hydrocarbons than an average car did before laws limiting such vehicle pollution were implemented." Even so, these remaining emissions can have a significant impact on human health and the environment.

Climate Change

Fossil fuels account for over 70 percent of the electricity generated in the United States and nearly all of the fuel consumed in the transportation sector. The continued use of fossil fuels in these sectors presents many environmental challenges, particularly global climate change. To address this environmental challenge, the President has proposed the Climate Change Research and National Climate Change Technology Initiatives to improve scientific understanding of the global climate system and to work toward long-term reductions of carbon dioxide emissions resulting from the use of fossil fuels. The production of hydrogen from domestically available and economic fossil fuels and subsequent capture and sequestration of carbon dioxide directly respond to these initiatives.

FE HYDROGEN FROM FOSSIL FUELS — TODAY'S TECHNOLOGY

Today's hydrogen production technologies are adequate to produce and deliver hydrogen in sufficient quantities to meet refining and chemical industries' needs. However, before large-scale hydrogen use can be a clean, affordable option, there is a need for considerable cost reduction and technical improvements throughout the entire hydrogen system - production, delivery, storage, conversion, and application.

It is anticipated that coordination among Office of Fossil Energy R&D programs will be needed to lower cost, improve efficiency, and accomplish carbon dioxide capture and sequestration when fossil resources are used to produce hydrogen. The most economic and environmentally responsive process for the production of hydrogen will be one utilizing the potential of advanced technologies now in, or being proposed as part of, the FE RD&D programs. Table 1 compares the cost to produce hydrogen from selected technologies and resources. A more detailed version of Table 1 and the analyses cited can be found in the Appendix (Table A-1). Table 1 shows that natural gas and coal are the most economical choices to provide the hydrogen necessary to begin the transition to a sustainable energy system. If the technology development objectives of the FE Hydrogen Program are achieved, the production cost of hydrogen from natural gas and coal, including carbon capture and sequestration, will be about $4.00 per million Btu or lower by 2020.

Table 1: Cost Comparison of Selected Hydrogen Production Technologies

Resource	Technology	Hydrogen Cost ($/MMBtu) / ($/kg)	Year Technology is Available
Natural Gas*	Steam Methane Reforming, PSA, No Sequestration	5.54 / 0.75	Current
Natural Gas*	ITM Synthesis Gas Generation, Advanced Membrane Separation, CO_2 capture	4.15 / 0.56	2013
Coal	Gasification, Shift, PSA, No Sequestration	6.83 / 0.92	Current
Coal	Advanced Gasification, Membrane Separation, CO_2 Sequestration	5.89 / 0.79	2015+
Coal**	Advanced Gasification, Membrane Separation, Co-Production of Power, CO_2 Sequestration	3.98 / 0.54	2015+
Biomass	Pyrolysis to bio-oil followed by steam reforming	(9 – 16) / (1.21 – 2.16)	2015+
Nuclear	Sulfur-Iodine Cycle (Thermochemical Process)	9.70 / 1.31	2020+
Electrolysis	Electricity Cost at 4 cents/kWh	(19 – 22) / (2.56 – 2.97)	Current

*These two cases are based upon a natural gas price of $3.15/MMBtu. Hydrogen costs will increase or decrease from these values at roughly 1.5 times the change in natural gas price above or below $3.15/MMBtu.
**The hydrogen cost in this case is based upon achievement of the associated Vision 21 Program goals. The value of power produced in the process is assumed to be 53.6 mils/kWh.

It should be noted also that the success of the R&D effort to economically utilize fossil fuels as a source of hydrogen is dependent upon successfully achieving the goals of a number of associated R&D efforts of the FE program. These associated programs include, but are not limited to:

- carbon dioxide capture and sequestration,
- conversion of hydrogen to power through fuel cells, and
- improvements in gasification technologies to improve efficiency of producing synthesis gas.

Hydrogen Industry Today

It has been estimated by Air Products and Chemicals, Inc. that the U.S. demand for hydrogen currently is about 9 million tons per year.[1] Of this amount, about 1.5 million tons is merchant hydrogen production that is sold to refineries and chemical plants.

In refineries, hydrogen is produced as a by-product of naphtha reforming, and any supplemental hydrogen is produced from steam reforming of natural gas. The chemical industry also utilizes hydrogen, mostly in the manufacture of ammonia and other nitrogen-based fertilizers. Hydrogen for the chemical industry is also produced from steam reforming of natural gas, although some chemical plants use coal gasification (i.e., partial oxidation) to produce hydrogen. In total, about 95 percent of U.S. hydrogen production for supplemental refinery needs and in the chemical industries is produced from natural gas utilizing steam reforming technology.

Current Technology — Steam Reforming of Natural Gas

Steam reforming is a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam (Figure 4). The result is a mixture of hydrogen, carbon monoxide, carbon dioxide and water that is produced in a series of three reactions. The first reforming step catalytically reacts methane with steam to form hydrogen and carbon monoxide in an endothermic reaction. The carbon monoxide is then "shifted" with steam to form additional hydrogen and carbon dioxide in an exothermic reaction. The carbon dioxide is removed using one of several adsorption processes. Trace amounts of carbon monoxide and carbon dioxide are removed by exothermically reacting the compounds with hydrogen to form methane and water. Finally, hydrogen is separated in preparation for its final use.

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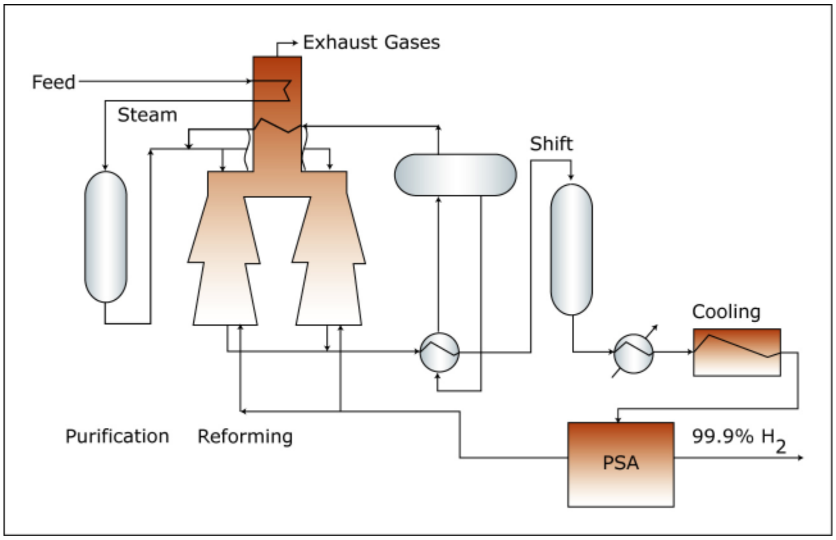
[1] Katsaros, Arthur. Air Products and Chemicals, Inc. *U.S. Industrial Hydrogen Infrastructure Presentation.* November 2001.

Figure 4: Steam Methane Reforming Technology

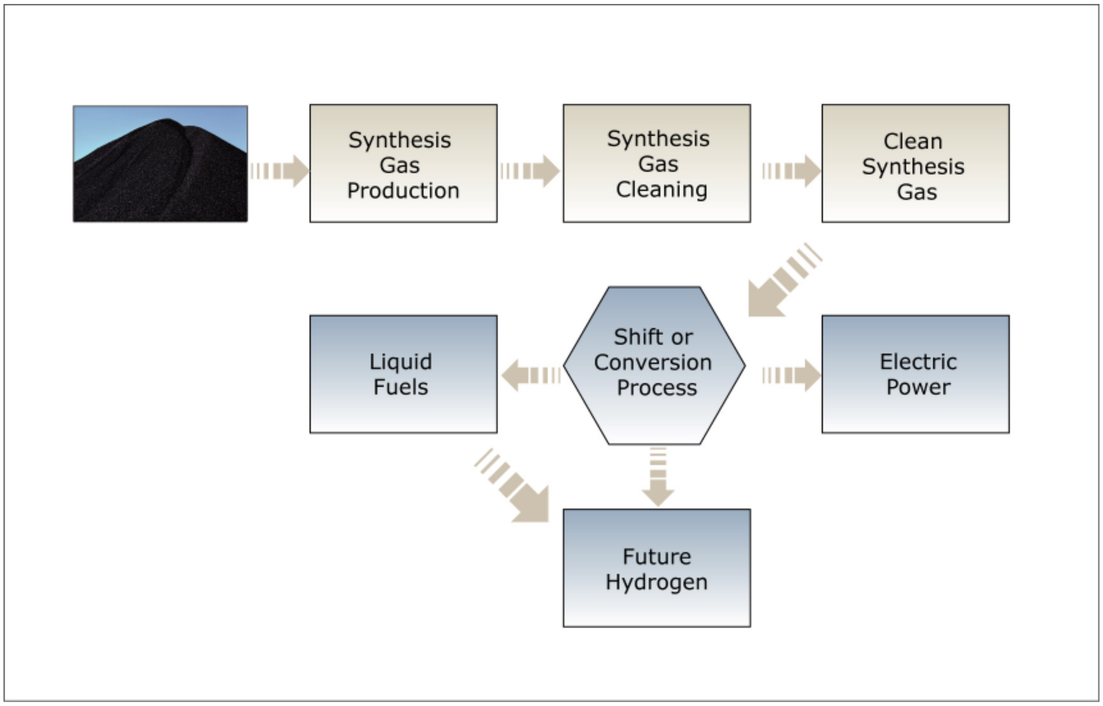


Current Coal Technology — Gasification and Conversion

Today, hydrogen is produced from coal by gasification and the subsequent processing of the resulting synthesis gas, and is used primarily to produce ammonia for fertilizer. Another market is being developed whereby coal-derived synthesis gas is being converted to methanol for use as an intermediate for chemical production, but which could also be used as a hydrogen carrier for subsequent reforming applications. This methanol production technology is being demonstrated successfully at the Eastman Chemical Complex in Kingsport, Tennessee.

In its simplest form, the overall technology used to produce hydrogen from coal is shown schematically in Figure 5. The coal is first gasified with oxygen and steam to produce a synthesis gas consisting essentially of carbon monoxide and hydrogen. This synthesis gas is cleaned to remove all impurities and shifted to produce additional hydrogen. The clean gas is then sent to a separation system to recover hydrogen. The residual gas from this separation can be recycled or combusted for its heat. The synthesis gas can also be converted into hydrocarbons and oxygenates for upgrading to liquid transportation fuels, or reformable fuels to produce hydrogen for fuel cell applications.

Figure 5: Current Hydrogen from Coal Production Process



HYDROGEN FROM FOSSIL FUELS — THE RD&D PROGRAM

Hydrogen Demand Scenarios

Hydrogen derived from fossil fuels and consumed in advanced fuel cell vehicles (FCVs) will have a significant benefit to the Nation's energy security and the environment. When light duty FCVs reach 50 million vehicles, petroleum imports will be reduced by 1.5 million barrels per day, and by 3 million barrels per day when FCVs reach 100 million vehicles. The Nation currently has about 210 million light duty vehicles that consume about 8.1 million barrels per day of petroleum in the production and use of gasoline and diesel fuels.

Emissions will be reduced significantly with fossil fuel-derived hydrogen use in these advanced hydrogen-powered FCVs, which are estimated to use one-third the energy per mile traveled compared with future gasoline internal combustion engine (ICE) vehicles. For example, even without carbon sequestration, domestic hydrogen from coal production and use in FCVs is estimated to reduce carbon dioxide emissions by 278 million tonnes per year for every 100 million FCVs. This reduction is equal to about 24 percent of the Nation's current carbon dioxide emissions associated with all of today's light duty vehicle fleet. When combined with sequestration, this same hydrogen from coal production and use in FCVs is estimated to reduce carbon dioxide emissions by 537 million tonnes per year, an amount that equals about 45 percent of current carbon dioxide emissions associated with today's light duty vehicles.

These estimates are based on a comparison of the production of the fuel (either hydrogen or petroleum products) and delivery to the service station, followed by use in either advanced FCVs or advanced gasoline ICE vehicles. This system pathway therefore includes the manufacture, transportation and consumption of fuel in these two transportation system technologies (FCV and ICE).

Table 2 shows the impact that centrally produced hydrogen from coal and natural gas, used in FCVs, will have on criteria pollutants, imports of oil, greenhouse gas emissions, energy use, and other criteria. For the case in which FCVs reach 100 million vehicles, if all hydrogen is produced from natural gas, SOx, NOx, and particulate matter less than 10 microns in diameter (PM10) are estimated to be reduced by 68,000 metric tonnes per year, 96,000 metric tonnes per year, and 28,000 metric tonnes per year, respectively. In the case of coal-derived hydrogen, reductions of SOx, NOx and PM10 are estimated to be 22,000 metric tonnes per year, 51,000 metric tonnes per year, and 20,000 metric tonnes per year, respectively.

The Nation currently consumes about 1,050 million tons of coal per year, all of which is produced domestically. Coal demand is estimated to increase only 14 percent, or 145 million tons annually, to produce the 20 million tons of hydrogen needed to fuel 100 million FCVs. In this case, energy savings are estimated at nearly $35 billion annually as coal is used instead of 3 million barrels per day of petroleum imports to fuel these light duty vehicles.

Energy savings estimated at $23 billion annually could be realized with efficient natural gas-to-hydrogen production and use in FCVs. The natural gas needed to produce 20 million tons of hydrogen per year to fuel 100 million advanced FCVs is 3.1 trillion cubic feet (tcf). However, natural gas consumption will be reduced by about 1.6 tcf/year in the refining sector and fuel production/blending operations. As a result, net annual natural gas consumption is estimated to increase by 1.5 tcf, or about 7 percent of the Nation's current annual natural gas demand of 23 tcf.

This analysis assumes hydrogen from natural gas plants have a nominal capacity of about 150 million standard cubic feet (MMscf) per day. The technology used is efficient steam methane reforming (SMR) with heat recovery but without sequestration. A total of 148 SMR plants are estimated to be needed to produce 20 million tons of hydrogen needed to fuel 100 million FCVs. In the case of hydrogen from natural gas with sequestration, advanced ITM syngas reactors are assumed to have equal thermal efficiency with SMR technology, but with sequestration. The size of these ITM syngas reactor hydrogen plants is assumed the same as SMR hydrogen plants.

Hydrogen from coal technology benefits analysis assumes that hydrogen plants also have a capacity of about 150 MMscf/day. These efficient 3,000 tons of coal per day plants use integrated gasification combined-cycle (IGCC) technology with carbon capture and sequestration, as shown in Table 4, Case 2 (p. 35). A total of 156 of these hydrogen from coal plants would be required to provide enough hydrogen to fuel 100 million advanced FCVs.

Assumptions for both advanced FCVs and ICE vehicle operation efficiency and fuel delivery are from Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model, version 1.5a. Technology assumptions are based on "Long-Term Technologies" in the model, instead of current technology. In addition, this model estimates each portion of the full fuel-cycle energy use and emissions associated with various transportation fuels and advanced vehicle technologies applied to motor vehicles. The GREET model has been used in numerous joint government and industry studies, such as the June 2001 study "Well-to-Wheel Energy Use and Greenhouse Gas Emissions of Advanced Fuel/Vehicle Systems – North American Analysis".

The emission reductions and benefits shown in Table 2 and previously discussed, are based mainly on the GREET 1.5a model. In that model, FCVs are three times as efficient as future gasoline ICE vehicles. Using these estimates, 20 million tons of hydrogen would be consumed annually to fuel 100 million FCVs. Since FCV technology has not yet been developed, there is uncertainty in its ultimate efficiency. Some have estimated that FCVs may only have twice the energy efficiency of future ICE vehicles. If that scenario were to occur, some benefits shown in Table 2 would be reduced, but petroleum imports would still decrease by the same amount when hydrogen is produced from natural gas or coal. However, if FCVs were only twice as efficient as ICE vehicles, hydrogen demand would increase to 30 million tons per year for each 100 million FCVs. Criteria pollutants and greenhouse gas emissions from fossil fuel-derived hydrogen use in FCVs would increase by 50 percent, but they would still be significantly lower than gasoline use in future ICE vehicles, even without sequestration. With carbon capture and sequestration, these emissions will be virtually eliminated. Table A-2 in the Appendix provides more detail on the emissions reductions and benefits associated with FCVs that have twice the energy efficiency of future ICE vehicles.

Table 2: Impact of Centrally-Produced Hydrogen from Natural Gas and Coal and Use in Light-Duty FCVs that are Three Times as Efficient as ICE Vehicles in the Long Term (a)

	Hydrogen from Coal		**Hydrogen from Natural Gas**	
Number of Light Duty FCVs	50 million	100 million	50 million	100 million
Number of Hydrogen Plants	78	156	74	148
Hydrogen Production, million short tons per year	10.1	20.2	10.1	20.2
Capital Cost of Hydrogen Plants; $ billion (current dollars)	33	66	11	21
Emissions Reductions				
SO_x, thousand tonnes per year	22	43	34	68
NOx, thousand tonnes per year	51	102	48	96
PM10, thousand tonnes per year	20	40	14	28
CO_2, million tonnes per year (no sequestration)	139	278	189	377
CO_2, million tonnes per year (with sequestration)	269	537	278	555
Other Impacts				
Energy Savings, $ billion per year (current dollars)	17	35	12	24
Reduce Petroleum Imports, million barrels per day	1.5	3.0	1.5	3.0
Natural Gas Displaced trillion cubic feet per year	0.8 decrease	1.6 decrease	0.8 increase	1.5 increase

(a) Based on a system analysis from a central hydrogen plant, pipeline delivery of hydrogen to refueling stations and use in efficient FCVs, compared with oil refining, delivery of gasoline and use in ICE vehicles.

Sources:

Argonne National Laboratory GREET 1.5a model, Per-Mile Fuel-Cycle Energy Use and Emissions for long-term technology light duty vehicles, assumed to be 55% passenger cars, 25% Light Duty Truck Class 1, and 20% Light Duty Truck Class 2. The GREET 1.5a model provides Btu/mile use of energy, broken down by fossil energy, petroleum energy and non-fossil energy, and SOx, NOx, and PM10, among other emissions, on a fuel-cycle basis. Except for the hydrogen from coal plant analysis, GREET 1.5a assumptions were used in the above table, including the assessment that FCVs use one third the energy per mile driven as ICE vehicles.

Hydrogen from Coal, Mitretek Technical Paper, MTR 2002-31, July 2002. This case is also used in this Office of Fossil Energy Hydrogen from Natural Gas and Coal Program Plan as Case 2 in Table 4 (p. 35). This case defines the quantity of coal, and therefore carbon, used to produce hydrogen.

SAIC, March 2003 presentation, which indicates advanced coal-fired IGCC plants emit 0.09 lbs NOx/MMBtu of coal, and 0.08 lbs of SO2/MMBtu at 98 percent recovery. Estimates used in the above analysis assume SO_2 recovery is 99 percent with emission of only 0.04 lbs SO_2/MMBtu through more severe operation of a Rectisol unit.

Hydrogen Production Facilities Plant Performance and Cost Comparisons, Parsons Infrastructure and Technology Group, Final Report, March 2002. Use of current steam methane reforming technology case. This case defines the quantity of natural gas, and therefore carbon used to produce hydrogen. Since both the Parsons and GREET 1.5a natural gas to hydrogen energy efficiency were essentially identical, the GREET 1.5a assumptions were selected for use.

FE Program Goal

The overall goal of the Hydrogen from Natural Gas Program and the Hydrogen from Coal Program is to demonstrate the capability and viability of producing hydrogen from our domestic natural gas and coal resources in an economic, reliable, safe, and environmentally sound manner. In addition, the program will evaluate the options available to achieve the most efficient and effective low-cost methods for distribution of the produced hydrogen.

To reach these overarching program goals, the FE hydrogen from natural gas and coal programs have set the following three significant long-range goals:

- By 2011, an alternative hydrogen delivery system will be optimized and available,
- By 2013, natural gas-based hydrogen systems will be capable of producing hydrogen with capture of carbon dioxide at 25 percent lower costs than current commercial means, and
- By 2015, coal-based hydrogen systems including carbon dioxide capture will be capable of producing hydrogen at 25 percent lower costs than current coal-based commercial means.

The achievement of these goals will result in technologies and processes for affordable hydrogen from fossil fuels in adequate volumes to provide a pathway to a long-term, hydrogen-fueled infrastructure, subsequently reducing urban and regional air pollution and greenhouse gas emissions.

Hydrogen from Natural Gas

Goal

2013 - Natural Gas Technology Modules Reduce the Cost of Hydrogen Produced from Natural Gas by 25 percent

Milestones

Major milestones are presented below. Figure 6 provides all intermediate and final milestones for the Hydrogen from Natural Gas Program.

- 2005: A 0.5 million standard cubic feet per day (MMscfd) hydrogen ITM production unit demonstrated
- 2010: Pre-commercial ITM technology unit producing 15 MMscfd of hydrogen demonstrated
- 2011: Low-cost, small-footprint plant for hydrogen production demonstrated
- 2013: Modules to reduce cost of hydrogen (and synthesis gas) production from natural gas by 25 percent available

Barriers

Steam reforming of natural gas is a mature technology, operating at or near the theoretical limits of the process that is used to produce nearly all the hydrogen (in the form of synthesis gas, a mixture of hydrogen and carbon monoxide) in the chemical industry and for supplemental hydrogen production in refineries. Once synthesis gas is produced and shifted, hydrogen is separated from the mixed gas stream using another mature technology, pressure swing adsorption (PSA). The associated cost to produce and deliver hydrogen with these technologies is too high for it to compete economically with conventional liquid fuels, such as gasoline or diesel fuel. Also, these hydrogen production system technologies are mature, and there is limited opportunity for cost and/or efficiency improvements.

During the steam reforming process, some natural gas is burned with air (80 percent nitrogen and 20 percent oxygen) in the furnace to produce the high temperatures required in the reactor. The furnace flue carries the combustion by-products of carbon dioxide, NOx, and inert nitrogen through the stack where it is emitted into the atmosphere. Capture of carbon dioxide from the mixed flue gas stream would be expensive. The development of novel technologies that could reduce the cost to produce hydrogen or capture carbon dioxide are not undertaken by industry without government joint support because of the associated high financial risk and the absence of promising candidate technologies.

Solutions

The economic barrier represented by the current use of steam methane reforming and PSA separation is being reduced and/or eliminated through the development and potential use of the Ion Transport Membrane (ITM) syngas reactor system. In a single reactor, these systems are capable of separating air to produce oxygen and subsequently use the oxygen in the partial oxidation of natural gas to generate synthesis gas. This technology offers the potential to be scalable without an associated significant increase in the unit cost. With the advanced ITM syngas reactor systems, after shifting and hydrogen separation, the remaining concentrated carbon dioxide can be captured or sequestered or used for industrial or other applications.

The mature steam reforming process, by contrast, burns a portion of the natural gas feed with air to generate the high temperatures needed for the process, which produces a mixed carbon dioxide, nitrogen and NOx gas stream that is emitted to the air through the flue. Separation of carbon dioxide from this flue gas stream is too costly to be an economic alternative. In addition, PSA hydrogen separation is an expensive technology that can be avoided if advanced membrane separation of synthesis gas technology is developed. Joint government/industry research is needed to identify, design, demonstrate, and commercialize these new and advanced technologies. An alternative technology with potential applications in small plants also being considered is advanced autothermal reforming.

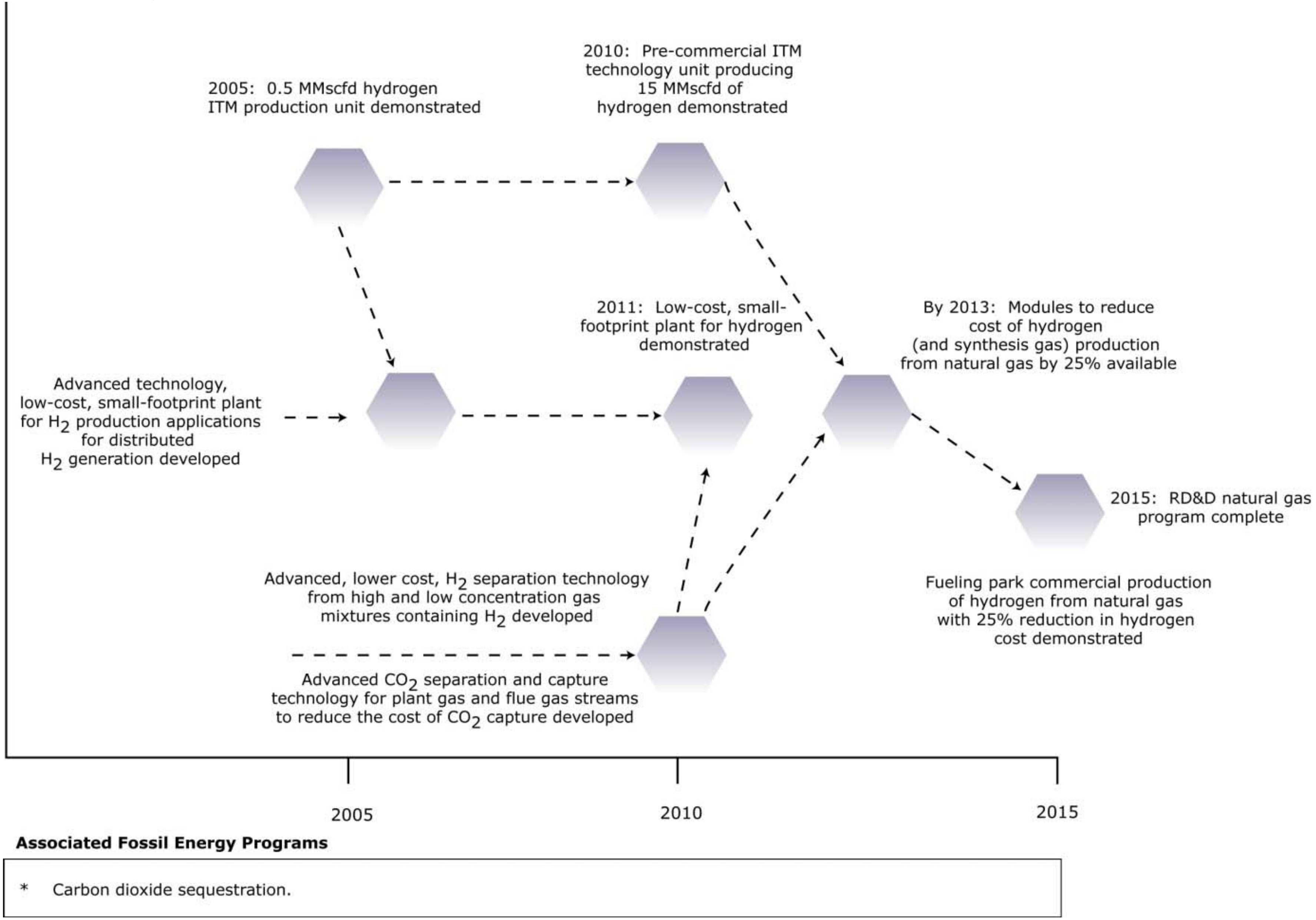
Benefits

Development of technologies to lower the cost of hydrogen from natural gas will enable the early transition to use clean hydrogen technologies, such as fuel cell vehicles (FCVs). The benefits of using low-cost hydrogen from natural gas and, in the future, potential resources of methane hydrates in advanced hydrogen utilization technologies would be improved energy security due to reduced petroleum imports, reduced criteria pollutants and reduced greenhouse gas emissions. Advanced FCVs powered by natural gas-derived hydrogen can replace gasoline internal combustion engine vehicles. For every 100 million FCVs fueled by natural gas-derived hydrogen, oil imports will be reduced by 3 million barrels per day and carbon dioxide emissions will be reduced by over 375 million tonnes per year, with carbon capture, 550 million tonnes. Criteria pollutants such as SOx, NOx, and PM10 will also be reduced by significant amounts (see Table 2, page 18).

Introduction of small-scale, lower capital cost hydrogen plants will allow earlier production of low-cost hydrogen. Because of the small footprint, construction time is shorter than for large hydrogen plants. Use of small-footprint facilities will reduce the need for significant delivery and transportation infrastructure. Large hydrogen plants that use novel ITM reactor systems will have even lower costs to produce hydrogen because of the economy-of-scale benefits and can become a significant source of hydrogen in the near to mid term.

The low-cost hydrogen production from natural gas technology can be the bridging technology to enable not only early transition to the hydrogen economy but also provide a platform for wider distribution of hydrogen production facilities that will support technologies such as fuel cell vehicles in a shorter period of time. For example, both large-scale and small-footprint plants producing hydrogen from natural gas can provide the earliest, low-cost transitional source of hydrogen for the FreedomCAR program reducing the Nation's energy consumption and reducing pollution compared to transportation alternatives. It is the integration of this innovative technology with the results of associated technology that allows capture of carbon dioxide and reduces NOx.

Figure 6: Hydrogen from Natural Gas Program – Major Technical Milestones



Hydrogen from Coal

Goal

2015 - 60 Percent Efficient, Zero Emissions, Coal-Fueled Hydrogen and Power Co-production Facility Operational

Milestones

Major milestones are presented below. Figure 7 provides all intermediate and final milestones for the Hydrogen from Coal Program.

- 2006: Advanced hydrogen separation technology including membranes tolerant of trace contaminants identified
- 2011: Hydrogen modules for coal gasification combined-cycle co-production facility demonstrated
- 2015: Zero-emission, coal-based plant producing hydrogen and electric power (with sequestration) which reduces cost of hydrogen by 25 percent compared to current coal-based plants demonstrated

Spotlight on FutureGen

On February 27, 2003, Secretary of Energy Spencer Abraham announced the $1 billion FutureGen initiative to design, build, and operate the world's first coal-fired, zero emissions plant integrated with carbon sequestration. The goal of the project is to produce electricity at a cost increase no greater than 10 percent higher than non-sequestered systems, and hydrogen at a cost of $4.00/MMBtu. The FutureGen prototype plant may provide a venue in which project researchers have the opportunity to gain large-scale, real-world experience for technologies developed by the Hydrogen from Coal Program. This experience can help reduce the technical and economic risks associated with developing new, innovative technologies while successfully meeting the program's goals and milestones. The advanced technologies developed under the Hydrogen from Coal program will support the FutureGen initiative.

Barriers

Partial oxidation of coal is a promising technology for the production of electric power that uses integrated gasification combined-cycle (IGCC) technology. However, there currently are no commercial demonstrations of these joint power and hydrogen production plants. Partial oxidation, or gasification, combines coal, oxygen and steam to produce synthesis gas that is cleaned of impurities such as sulfur or mercury. To produce hydrogen, this synthesis gas is shifted using mature water-gas shift reactor technology to generate additional hydrogen and convert carbon monoxide to carbon dioxide. Hydrogen is subsequently separated from the gas stream. Currently, this separation is accomplished through the use of mature PSA technology which operates near its theoretical limit. In order to reduce costs, novel and advanced technology must be developed in all phases of the gasification/hydrogen production and separation process. Carbon dioxide produced in the hydrogen production process would be removed utilizing capture and sequestration technology now being developed in an associated program.

Solutions

Within the Hydrogen from Coal Program, R&D activities are focused on the development of novel processes that include:

- advanced water-gas shift reactors using sulfur-tolerant catalysts to produce more hydrogen from synthesis gas at lower cost;
- novel membranes for advanced, lower cost separations of hydrogen from carbon dioxide and other contaminants;
- advanced technology concepts that combine hydrogen separation and the water-gas shift reaction; and
- technologies that utilize fewer steps to separate carbon dioxide, hydrogen sulfide, and other impurities from hydrogen.

Novel catalysts and materials must be developed for this to succeed. Technology and engineering studies are also required for co-production and integration of coal gasification for power production with hydrogen production and separation. At the same time, cost reduction and process efficiency improvement are dependent upon R&D successes in a number of associated coal gasification technologies. These include:

- advanced ITM technology for oxygen separation from air;
- advanced cleaning of raw synthesis gas;
- improvements in gasifier design, materials and feed systems, and
- carbon dioxide capture and sequestration technology.

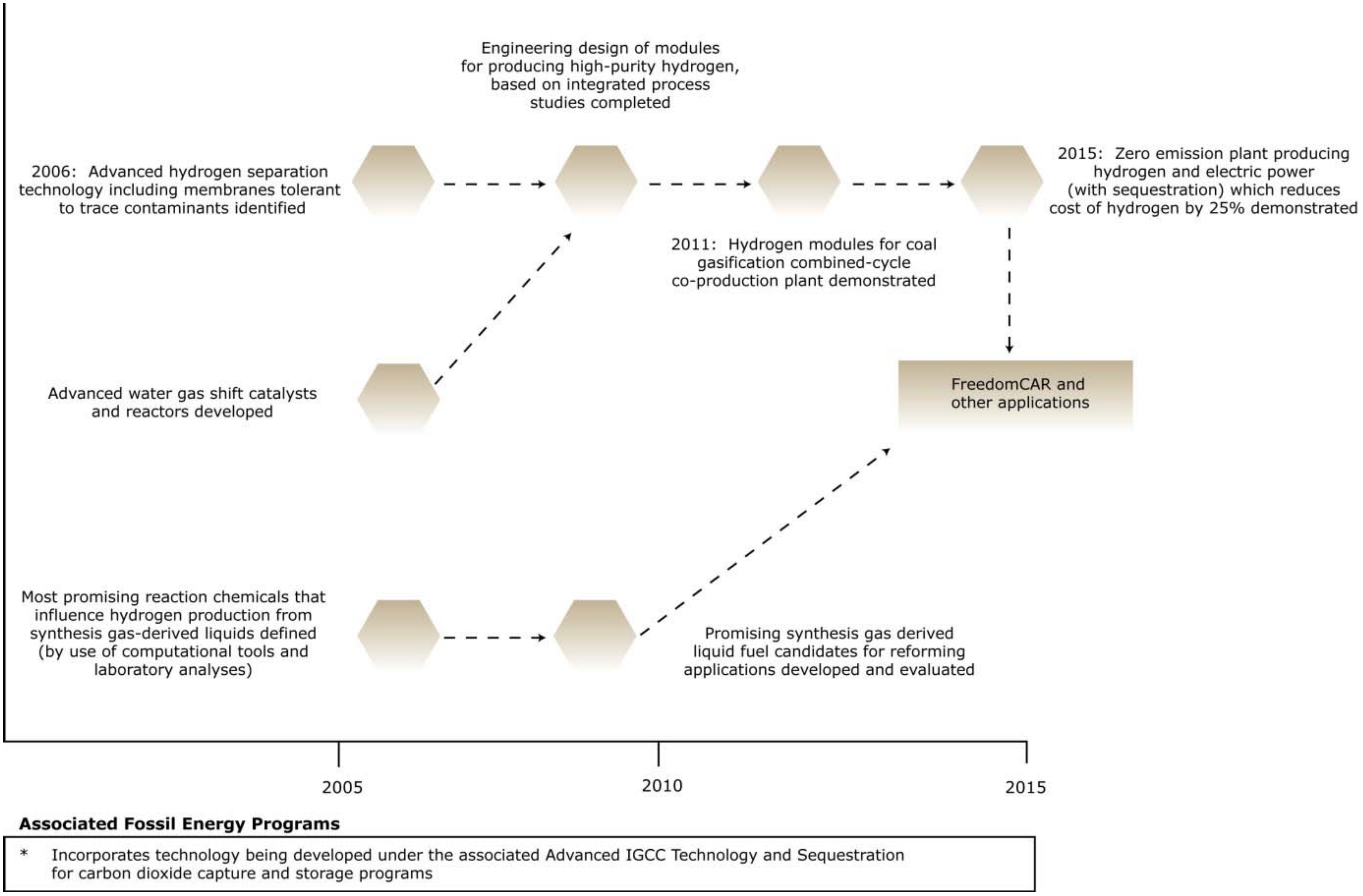
Joint government/industry research is needed to identify, design and demonstrate these new and advanced technologies if an economic alternative to current, mature technology is to be realized.

Benefits

Low-cost, hydrogen from coal technologies will allow the Nation’s 250-year supply of domestic coal to replace imported oil and improve the Nation’s energy security when used in advanced hydrogen technologies such as fuel cell vehicles (FCVs). The benefit of producing enough hydrogen in efficient coal-to-hydrogen technologies to power 100 million FCVs will be a reduction of 3 million barrels per day of imported oil. Even without carbon sequestration, carbon dioxide emissions will be reduced by over 275 million tonnes per year, and nearly 540 million tonnes per year with sequestration. Criteria pollutants of SOx, NOx, and PM10 will be reduced significantly (see Table 2, page 18).

Production of low-cost hydrogen from coal will reduce reliance on imported oil, increase the proportion of domestic energy resources that compose the Nation's energy mix, and provide a cost-effective source of hydrogen for the transportation sector and the associated FreedomCAR program. In this way, hydrogen from coal provides a mid-term transitional source of energy until the long-term goal of producing hydrogen from renewable and nuclear energy is realized. Successful development of carbon dioxide capture and sequestration technology will eliminate public concerns over any greenhouse gas emissions that may be generated by this technology.

Figure 7: Hydrogen from Coal Program – Major Technical Milestones



Delivery

Goal

2011 - Alternative Hydrogen Delivery System Optimized and Available

Milestones

- 2005: Identify and evaluate the most promising approaches and options for economic storage, handling and delivery of hydrogen

- 2008: Complete bench-scale tests of storage, handling and delivery technologies that, when integrated with the entire fuel production and delivery cycle, provide a cost to the consumer of no greater than $1.50 per gallon of gasoline equivalent (gge) by 2015.

- 2011: Complete tests and evaluations of the most promising hydrogen-rich, synthesis gas-derived liquid fuel candidates for reforming applications.

Barriers

Currently, hydrogen delivery infrastructure exists only for the small merchant hydrogen market that currently exists in the chemical and refining industries. This limited system lacks the scope or scale needed to deliver hydrogen outside of these limited industrial areas to potential large-volume end-user applications such as the FreedomCAR program. The existing liquid fuel (e.g., gasoline, diesel fuel, and jet fuel) delivery infrastructure is an entrenched, capital-intensive network that consists of pipelines, intermediate product storage, import terminals, and rail, barge and on-road truck delivery to end-use distribution stations that links the entire Nation. The existing natural gas delivery infrastructure is also a capital-intensive network that consists of import LNG terminals; significant storage to build inventory during low-demand, off-peak seasons; and pipelines to deliver product to end-users. Hydrogen has physical properties that may cause embrittlement of some high-strength steel piping materials and components (e.g. compressors and valves) currently used for natural gas. These systems would require modification for use in the delivery and distribution of hydrogen. In addition, natural gas pipelines may not be available or able to handle the additional volume. Therefore, it is likely that significant capital investment in dedicated hydrogen delivery infrastructure will be required before a hydrogen economy can be realized. The evaluation of options and the identification of the most optimum delivery system to include an alternative liquid fuel as consideration for a hydrogen carrier is a critical issue. In any consideration of advanced or modified hydrogen delivery systems, the unique characteristics of hydrogen must be considered.

Solutions

Computational studies and analysis of optimal, early-introduction hydrogen carriers is required in order to evaluate the most promising reaction catalysts and chemical process routes. Analysis is also needed to evaluate the trade-off between massive capital investments in central location hydrogen plants, associated pipelines, and delivery in a dedicated hydrogen infrastructure against the use of liquid and natural gas infrastructure to deliver hydrogen-rich fuels. It may be the case that these fuels can be reformed at end-use locations, instead of central locations, and the cost of small-scale, on-site reforming must be evaluated against the large capital costs of a dedicated hydrogen infrastructure.

Benefits

Identification and development of the best alternatives to produce and deliver hydrogen in the near term is needed to achieve the early introduction of efficient fuel cell technology. The efficient fuel cell will reduce the overall amount of fossil fuels consumed, thereby reducing greenhouse gas emissions and pollution from conventional fossil fuels. Utilization of synthesis gas to produce liquid hydrocarbons as hydrogen carriers will enable the use of abundant coal resources and reduce oil imports. Some synthesis gas-derived liquids can use existing refined liquid fuel infrastructure, which will reduce the need for significant capital investments in dedicated hydrogen infrastructure. The combination of carbon dioxide removal at the production site of the liquid hydrogen carrier with the significantly higher potential efficiency of fuel cell vehicle technology could result in substantially lower emissions per mile in the transportation sector.

HYDROGEN FROM FOSSIL FUELS — A BUDGET FOR THE HYDROGEN FROM FOSSIL FUELS PROGRAM

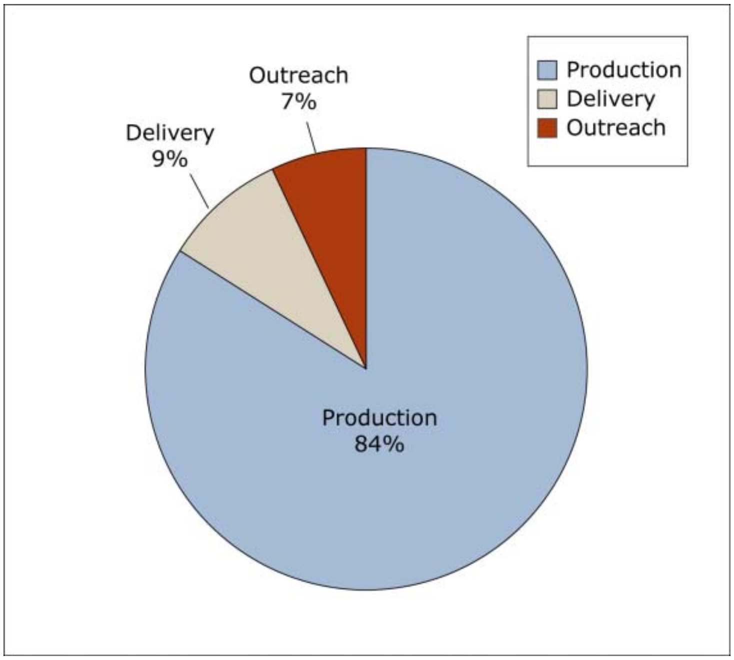
Office of Fossil Energy Hydrogen Program Budget

The budget for the FE hydrogen program for FY04 as currently planned is $11.6 million, with $5.0 million provided to the Hydrogen from Coal Program and $6.6 million to the Hydrogen from Natural Gas Program. Table 3 and Figure 8 show the breakout of the FE hydrogen budget for FY04 by category and what percentage has been allocated for each of these categories.

Table 3: FE Hydrogen Budget Breakout for FY04 ($million)

FE Hydrogen Budget	**Category**			
	Production	**Delivery**	**Outreach**	**Total**
Coal	4.3	0.5	0.2	5.0
Natural Gas	5.4	0.6	0.6	6.6
Total	9.7	1.1	0.8	11.6

Figure 8: FE FY04 Hydrogen Budget Breakout Percentage by Category



Figures 9 and 10 are Gantt charts that show a more detailed program planning breakout for the hydrogen from natural gas and coal programs, which is required to meet the program milestones and metrics. These charts also show some of the potential areas for research that will be conducted by the programs.

Figure 9: Hydrogen from Natural Gas Program

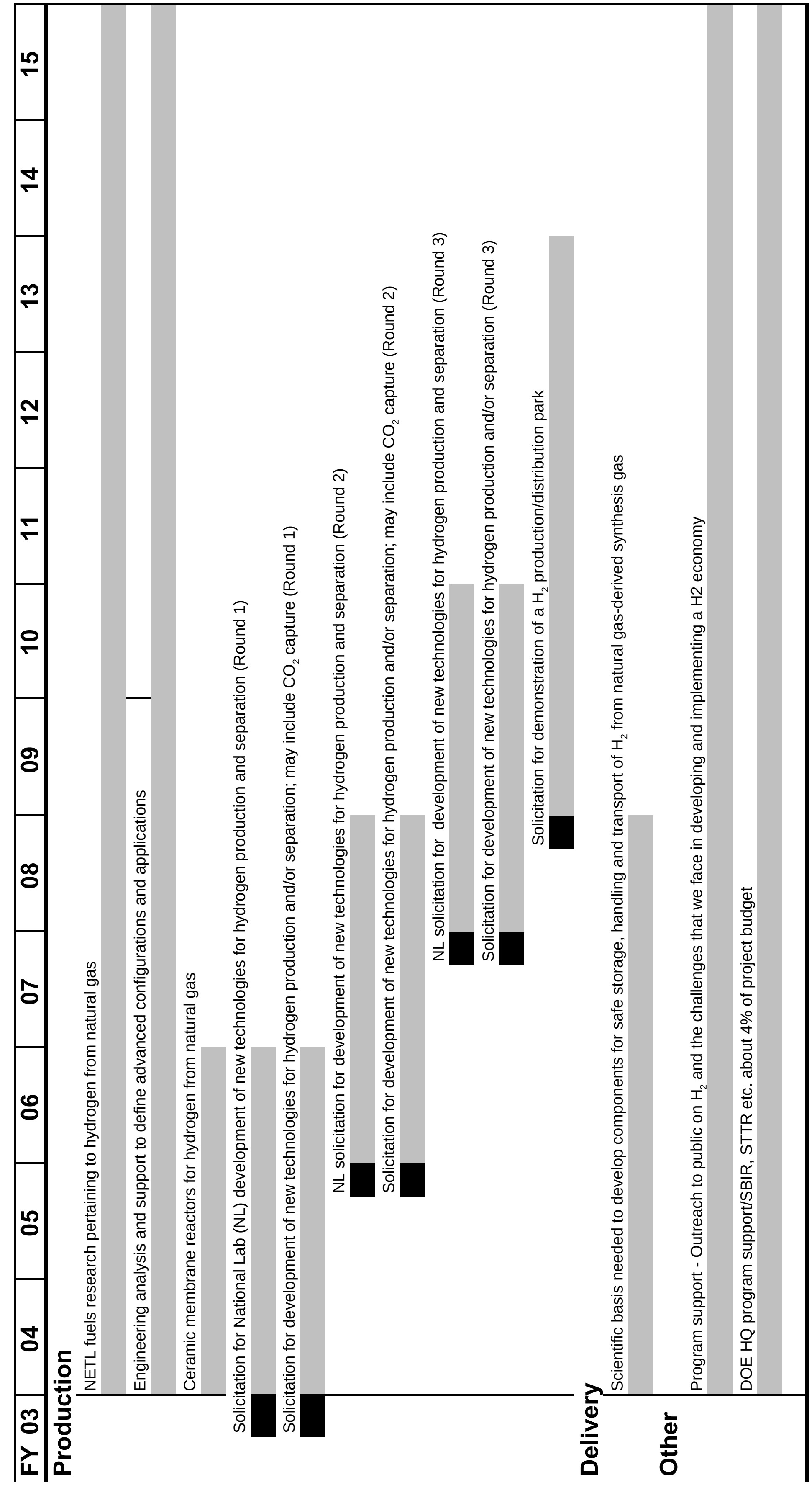
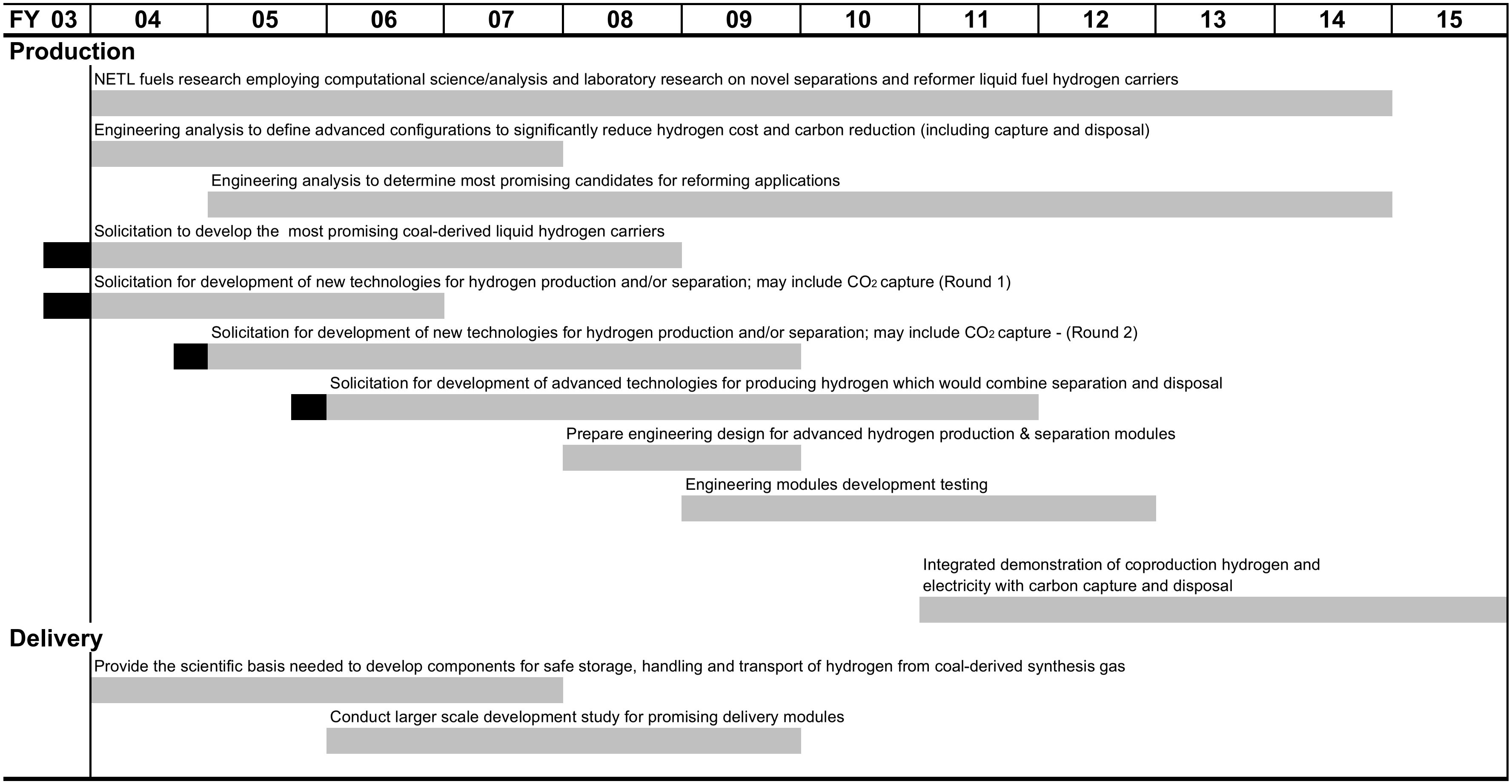


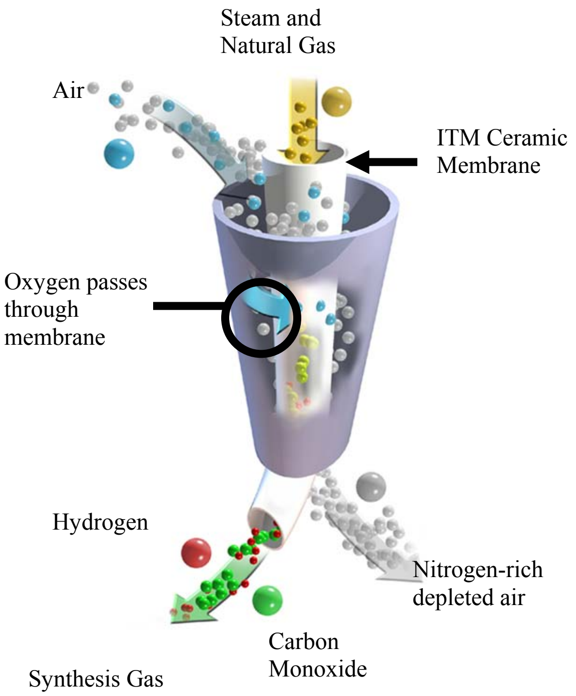
Figure 10: Hydrogen from Coal Program



FUTURE TECHNOLOGIES TO PRODUCE HYDROGEN FROM NATURAL GAS[2,3,4]

Steam reforming of natural gas is a mature process approaching its maximum theoretical process efficiency and is the primary one used to produce hydrogen from natural gas. However, there are advanced technologies, currently in various stages of development, which have the potential to reduce the cost to produce hydrogen from natural gas on both large and small scale.

Figure 11: Schematic of the ITM Synthesis Gas Generation Process



One of the promising technologies under development that shows significant potential in reducing the cost of producing hydrogen from natural gas is the application of ITM technology to generate synthesis gas. This technology combines the processes of oxygen separation from air and partial oxidation of natural gas into one, compact step (Figure 11). ITM synthesis gas generation technology utilizes non-porous ceramic membranes fabricated from multicomponent metallic oxides that conduct both electrons and oxygen ions at temperatures greater than 700°C. During operation, oxygen from a hot air stream is reduced by catalysts at one surface of the membrane to create oxygen ions. The oxygen ions flow through the membrane under a chemical gradient to the opposite membrane surface where they partially oxidize a pre-reformed hot mixture of steam and natural gas to form synthesis gas, a mixture of carbon monoxide and hydrogen. The ratio of hydrogen to carbon monoxide is partly dependent upon the amount of steam that is used. The synthesis gas then proceeds to a water-gas shift reactor where additional steam is added to convert the steam and carbon monoxide to more hydrogen and carbon dioxide. This mixture of hydrogen, carbon dioxide, and trace amounts of carbon monoxide is subsequently separated to produce a hydrogen product stream and a concentrated carbon dioxide stream. The carbon dioxide can be captured and eventually sequestered. Currently, the comparatively expensive PSA technology is used to separate hydrogen from synthesis gas. However, advanced membrane technologies that are under development have the potential to reduce the cost of this process step. Figure 12 is a schematic of the advanced technology process.

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[2] Office of Fossil Energy and the National Energy Technology Laboratory Project Factsheets, 2002.
[3] Air Products and Chemicals, Inc. technical literature, 2002.
[4] Proceedings of the 2000 to 2002 DOE Hydrogen Program Reviews.

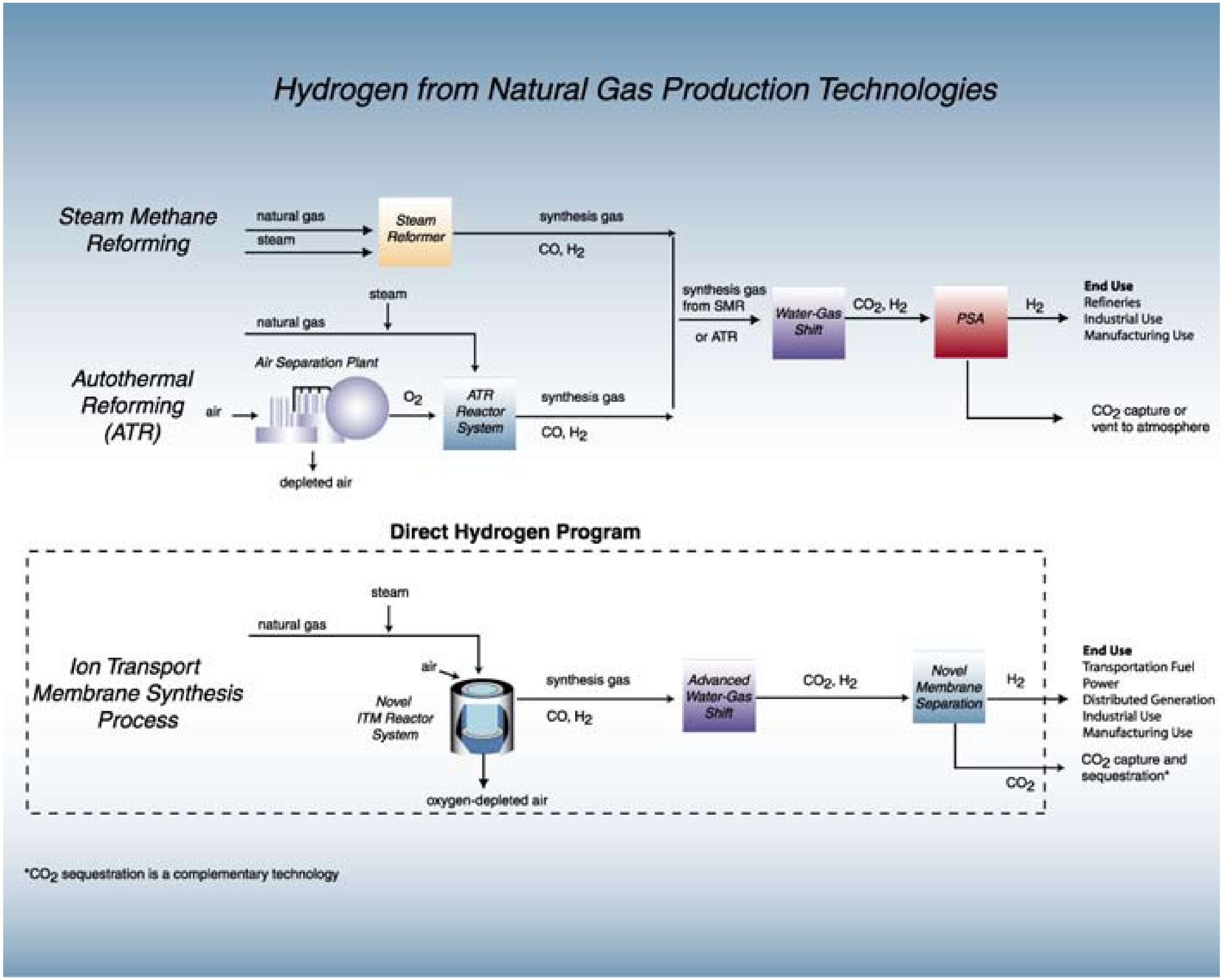
There are several key challenges that the ITM synthesis gas generation technology needs to address to reach its potential as a compact, low-cost hydrogen production process alternative to steam reforming. The membrane material used must show long-term stability in both reducing and oxidizing environments. The membrane must also allow large fluxes of oxygen to pass through so that optimal oxidation of the natural gas occurs. Long-term compatibility between the oxidation and reforming catalysts along the surface of the membrane must be exhibited. Reliable, leak-proof, metal-ceramic seals are also required.

In addition to the potential cost benefits of ITM synthesis gas generation technology, another benefit is its versatility due to its compact size. The technology has the potential to be used in small-footprint plants for distributed hydrogen generation purposes, as well as in large-scale industrial plant applications.

Distributed generation of hydrogen from small-footprint plants allows hydrogen to be produced near the end-user for fuel cell vehicle applications or industrial uses. The benefit of producing hydrogen near the end-user is that hydrogen delivery capital costs can be avoided. A small-footprint plant based on ITM synthesis gas reactor technology that produces 0.5 MMscfd of hydrogen at 5,000 pounds per square inch (psi) for FCVs was compared to trucked-in liquid hydrogen. Including the costs of hydrogen compression, storage, and dispensing, a recent industry study estimated that the small-footprint ITM plant could save 27 percent of the high-pressure hydrogen production costs compared to trucked-in liquid hydrogen.

Large-scale hydrogen production using ITM synthesis gas generation technology also has the potential to achieve cost benefits. An ITM synthesis gas generation process that produces 760 MMscfd of hydrogen at 100 bars (1,450 psi) and 14,000 tonnes/day of carbon dioxide at 80 bars (1,160 psi) for sequestration was compared to a conventional oxygen-blown autothermal reformer with a cryogenic air separation unit to supply oxygen. The comparison indicated that the ITM synthesis gas generation process could potentially save over 30 percent of the capital cost of synthesis gas generation and over 20 percent of the capital cost for the overall process. In addition, the process has a predicted thermal efficiency of 74 percent compared to 71 percent for the autothermal reformer process.

Figure 12: Schematic of Technology Process for Hydrogen Production from Natural Gas



FUTURE TECHNOLOGIES TO PRODUCE HYDROGEN FROM COAL[5]

At the present time, no coal-based facilities based on modern entrained gasification have been constructed that produce both hydrogen and electric power. Conceptual commercial plants have been simulated using computer models to estimate the technical performance and economics of a co-production plant producing hydrogen and power, based on current technology. Computer simulations have also been developed for conceptual plants that produce hydrogen and some excess power, based on advanced technologies that are presently not available for commercial deployment. The status of these advanced technologies varies. Some are already close to commercialization and others are further back in the R&D pipeline. Table 4 summarizes the information developed from two of these computer simulations. A more detailed evaluation of additional co-production cases can be found in the Mitretek report (5), and these cases are included in the hydrogen production cost table in the Appendix.

Table 4: Summary of Hydrogen from Coal Cases

	CASE 1	CASE 2
Carbon Sequestration	YES (87%)	Yes (100%)
Hydrogen (MMscfd)	119	158
Coal (Tons/day) (AR)	3000	3000
Efficiency (%HHV)	59	75.5
Excess Power (MW)	26.9	25
Power Value (mills/kWh)	53.6	53.6
Capital ($million)	417	425
RSP of Hydrogen ($/MMBtu)	8.18	5.89

Notes:
1) Coal cost is $29/ton (and is assumed to de-escalate at 1.5 percent below general inflation), and the assumed plant capacity factor is 85 percent.
2) For carbon sequestration, the co-produced power is assumed to have a value of $53.6/MWh, based on an additional cost of power production from Natural Gas Combined-Cycle (NGCC) plants with sequestration of 18 mills/kWh (reference EPRI report 1000316).
3) For sequestration, it is assumed that $10 per ton of carbon is added for sequestration after the concentrated carbon dioxide stream has been isolated, and the carbon dioxide stream is compressed to 200 bars (2,900 psi).
4) Financial assumptions used for these simulations: 25-year plant life; 67/33% debt/equity financing; 15% return on equity; 8% interest for a 16-year term; 3% inflation with coal de-escalation of 1.5% per annum below general inflation; 16-year double declining balance depreciation; 40% combined Federal and State tax rate; 3-year construction with 50% output in start-up year; carbon sequestration cost of $10/ton.

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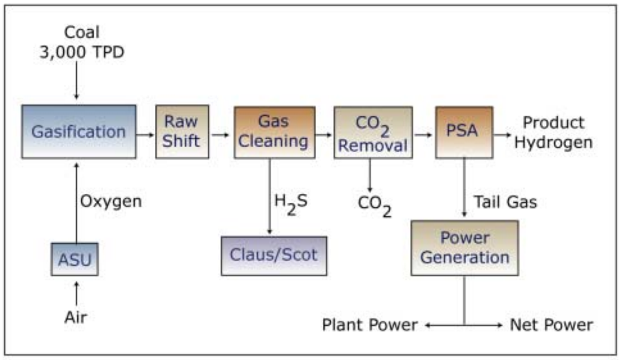
[5] Hydrogen from Coal, Mitretek Technical Paper MTR 2002-31, July 2002.

Case 1, shown schematically in Figure 13, is a process to produce hydrogen based on conventional technology utilizing carbon sequestration. The process assumes that a Texaco quench gasification system with conventional acid removal and a PSA system for hydrogen recovery is used. All of the carbon dioxide is removed prior to the PSA unit, is compressed to 200 bars (2,900 psi), and is assumed to be sequestered for an additional cost of $10 per ton of carbon. In this configuration, 87 percent of the carbon in the feed is sequestered. The capital cost of the plant is estimated at $417 million with a retail selling price (RSP) of the hydrogen at $8.18/MMBtu. The amount of hydrogen produced is 119 MMscfd, and there is 27 MW of excess power.

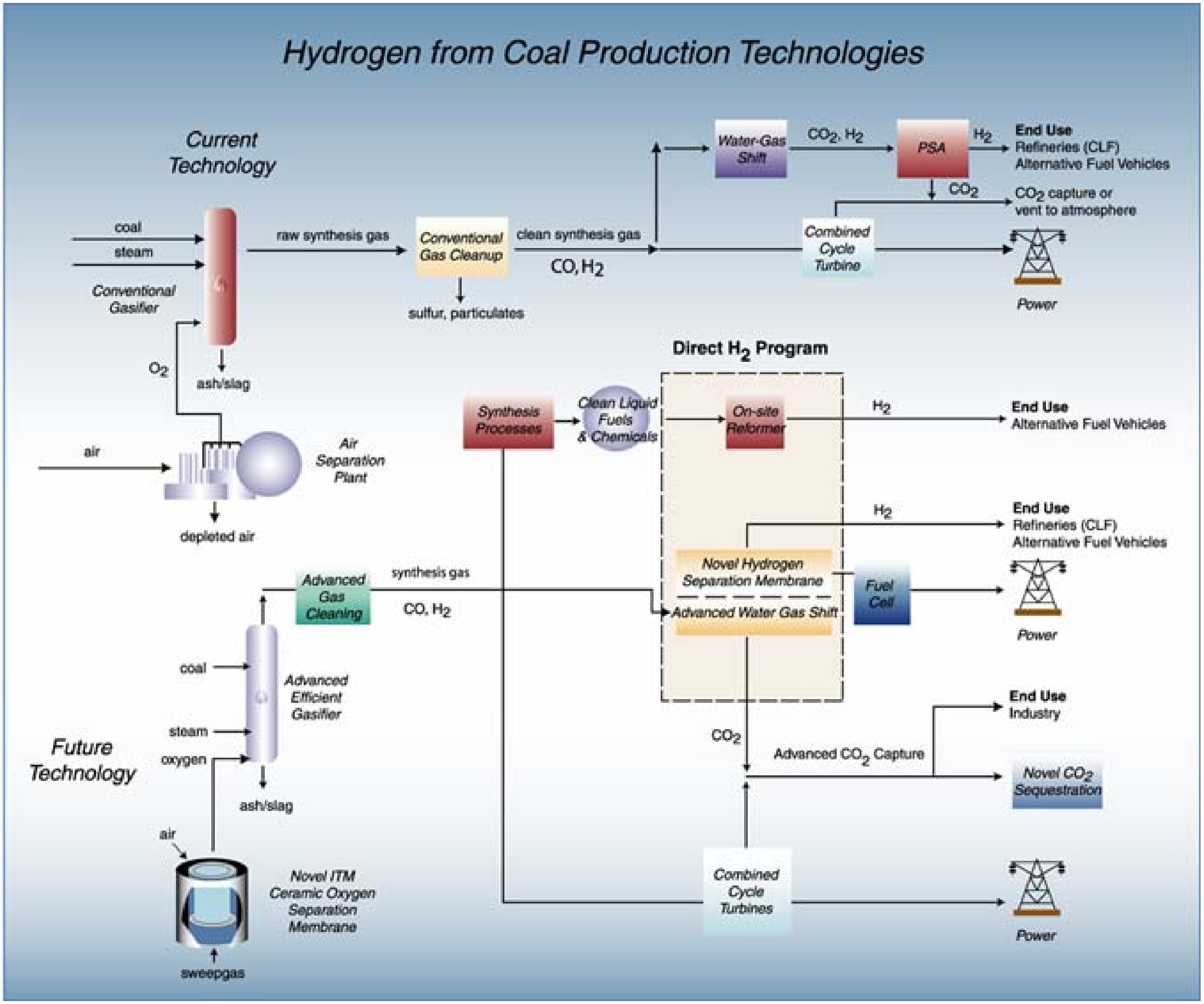
Figure 13: Schematic of Current Technology to Produce Hydrogen from Coal with Carbon Sequestration



Case 2 represents a process for hydrogen production from coal that uses advanced gasification technology, advanced membrane technology for hydrogen separation with carbon dioxide removal, and carbon sequestration. A schematic of the process is shown in Figure 14. In this configuration, advanced E-gas gasification with hot gas cleanup is used in combination with a ceramic membrane system operating at nearly 600ºC that is capable of shifting and separating hydrogen from clean synthesis gas. It is assumed that 90 mole percent of the synthesis gas is converted in this membrane system, assumed to be similar to the K25 system under development by Oak Ridge National Laboratory (ORNL). The hydrogen produced is separated at low pressure and must be compressed. The remaining synthesis gas, containing mostly carbon dioxide with some carbon monoxide and hydrogen, is then combusted with oxygen in a gas turbine to provide power for the plant. Oxygen is used so that a concentrated stream of carbon dioxide is produced for sequestration. Heat is recovered from both the gas turbine exit gas and from the hot hydrogen in heat recovery steam generators (HRSGs) where the steam produced is sent to a steam turbine to provide additional power. The capital cost for the facility is $425 million, with the required selling price of hydrogen estimated at $5.89/MMBtu.

Advanced concepts are planned to be developed after 2015 which would employ advanced gasification, combustion and turbine systems, membrane separation, and carbon capture and sequestration in a co-production plant producing hydrogen and electric power. These highly efficient, hydrogen and electricity co-production plants could provide significant additional reductions in the cost of hydrogen, reducing the cost to $4.00/MMBtu.

Figure 14: Schematic of Advanced Technologies to Produce Hydrogen from Coal



FE ASSOCIATED PROGRAMS

The successful development of low-cost, affordable hydrogen production from fossil fuels with sequestration of carbon is dependent on successful completion of several associated RD&D programs within the Office of Fossil Energy. The technologies are discussed below.

Gasification

Advanced coal gasification technologies will reduce the cost to produce electric power from coal using Integrated Gasification Combined-Cycle (IGCC) technology. The initial IGCC process technology produces synthesis gas that is cleaned and used to efficiently produce electric power in advanced combined-cycle turbines. Hydrogen from coal is produced from the synthesis gas generated by IGCC technology. Improved technologies developed in RD&D in the FE program will complement, and are necessary to produce, low-cost hydrogen from coal. These technologies include: improved feed handling systems, efficient gasifier design and materials engineering, advanced synthesis gas clean-up technologies, and advanced membrane separation technology to produce a lower cost source of oxygen from air.

Carbon Dioxide Sequestration

While hydrogen is a clean fuel with water as essentially its only by-product, emissions of greenhouse gases will be generated during its production from natural gas and coal. The hydrogen from natural gas program will investigate technologies to capture carbon dioxide as part of its activities to augment the carbon dioxide sequestration program where appropriate, because there is a difference in the concentration and pressures of the carbon dioxide in its effluent streams compared to process streams of coal-derived hydrogen systems. The Hydrogen from Coal Program will separate carbon dioxide from mixed hydrogen streams and will collaborate with, and take advantage of, the capture technologies being developed by the Office of Fossil Energy carbon sequestration program. Both the Hydrogen from Natural Gas Program and the Hydrogen from Coal Program, however, will utilize these sequestration technologies.

The FE carbon sequestration program is currently investigating technologies to inject carbon dioxide into enhanced oil and gas production systems and enhanced coalbed methane projects; to store carbon dioxide in underground reservoirs; to utilize the natural ability of vegetation and soils to store carbon; and to convert carbon dioxide into safe, harmless minerals. Development of carbon sequestration technology will also benefit the FE hydrogen program by sequestering carbon dioxide that is removed from the concentrated product streams that result during hydrogen production.

The goals of the FE carbon sequestration program are to provide economically and environmentally safe sequestration technologies. These technologies will offset projected growth in carbon dioxide emissions by 2015 at a cost of $10/ton of avoided carbon, with the potential to eventually offset at least one-half of any required reductions in emissions of global greenhouse gases. The development of cost-effective, safe sequestration methods will provide the United States with the opportunity to fully utilize its domestic fossil fuel resources to produce hydrogen during the Nation's transition to a sustainable hydrogen economy.

Fuel Cells

Solid State Energy Conversion Alliance (SECA) fuel cell technology is in its initial stages of development and requires improvements in all aspects of system technology. In distributed generation, a primary market for stationary fuel cell applications, the market risk and market potential are higher because of uncertainty surrounding the slow deregulation of the U.S. electric power industry.

No fuel cell type has been successfully commercialized. Early fuel cell marketers have had to rely on high-price, limited-niche markets to support the high cost of the technology. The SECA program is a joint government/private cost-shared program that has low fuel cell cost targets. SECA has identified fuel cell technologies to meet those low-cost targets that include: fuel processing, manufacturing, controls and diagnostics, power electronics, modeling and simulations, and materials. Successful development of novel and advanced low-cost processes will allow the SECA industry partners to have a wider, deeper market penetration from the start. In SECA, a 5- to 10-fold cost reduction and mass-customization manufacturing are required over existing technology to achieve widespread national deployment of fuel cells.

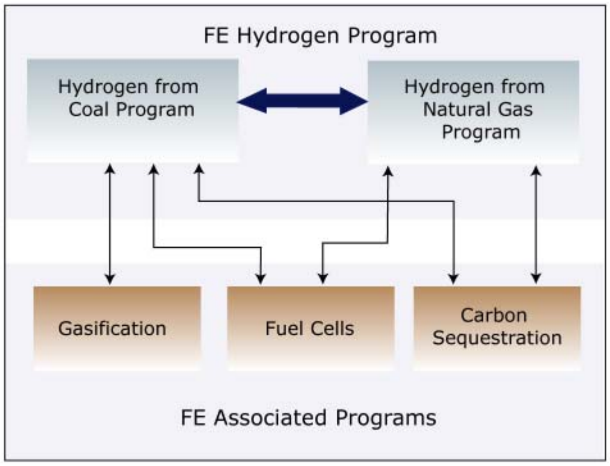
The key milestones for the SECA fuel cell program are: by 2010, 3 to 10 kW SECA fuel cells at $400/kW with target efficiencies of 40 to 60 percent demonstrated, and by 2015, hybrid SECA fuel cell/turbines that meet $400/kW system requirements with 70 to 80 percent efficiencies demonstrated.

INTEGRATED PROGRAM MANAGEMENT AND COORDINATION

The Hydrogen from Natural Gas Program and the Hydrogen from Coal Program will be managed separately by their respective program managers. However, the programs will be coordinated so that the potential for duplication of efforts is eliminated and better leveraging of resources occurs. It is expected that coordination of the hydrogen from natural gas and coal programs within FE will occur through the Hydrogen Coordination Group.

In addition, the hydrogen from natural gas and coal programs will coordinate their efforts with associated programs within the Office of Fossil Energy. Success of the FE hydrogen program is directly tied to the success of the following FE programs: coal gasification, carbon sequestration, and fuel cell development. Each of these programs will play a vital role in achieving the overall economic and environmental goals of the hydrogen energy system. To ensure a smooth and successful transition to a hydrogen energy system, it is important that there is communication between these programs. Figure 15 shows a schematic of one option that these programs may use to coordinate.

Figure 15: Coordination of Relevant FE Programs



The FE hydrogen program will also need to coordinate its activities with the hydrogen programs in the Office of Energy Efficiency and Renewable Energy, the Office of Nuclear Energy, and the Office of Science within DOE. Coordination of efforts and sharing of information and experience will help ensure the successful transition to a hydrogen energy system.

ACRONYMS

gge – gallon gasoline equivalent
kg – kilogram
kW – kilowatt
kWh – kilowatt-hour
mills – one-tenth of one cent
psi – pounds per square inch
tcf – trillion cubic feet
tpy – tons per year

ATR – autothermal reforming
CO – carbon monoxide
CO2 – carbon dioxide
DOE – Department of Energy
EIA – Energy Information Administration
EPRI – Electric Power Research Institute
FCV – fuel cell vehicle
FE – Office of Fossil Energy
FY – fiscal year
GHG – greenhouse gas
GREET – The Greenhouse gases, Regulated Emissions, and Energy use in Transportation model
H2 – hydrogen
HHV – higher heating value
HRSG – heat recovery steam generator
ICE – internal combustion engine
IGCC – integrated gasification combined-cycle
ILWG – Interlaboratory Working Group
ITM – ion transport membrane
LNG – liquefied natural gas
MW - megawatt
MWh – megawatt-hour
MMBtu – million British thermal units
MMscfd – million standard cubic feet per day
NEMS – National Energy Modeling System
NEP – National Energy Policy
NETL – National Energy Technology Laboratory
NGCC – natural gas combined-cycle
NL – National Laboratories
NOx – nitrogen oxides
ORNL – Oak Ridge National Laboratory

PM10 – particulate matter 10 microns in diameter or less
PSA – pressure swing adsorption
R&D – research and development
RD&D – research, development, and demonstration
RSP – retail selling price
SBIR – Small Business Innovative Research
SECA – Solid State Energy Conversion Alliance
SMR – steam methane reforming
SO_2 – sulfur dioxide
SOx – sulfur oxides
SOFC – solid oxide fuel cell
STTR – Small Business Technology Transfer
TPD – tons per day
U.S. – United States
VOC – volatile organic compounds

APPENDIX

HYDROGEN PRODUCTION COST COMPARISON

The following table provides a summary of hydrogen production cost comparisons for various resources and technologies and an estimate of when these technologies could be available. References to the sources of the information and notes on some of the relevant assumptions used for each resource and technology are also included at the end of the table. These tables are representative only, and other analyses of these costs might be found for the same pathway, which could be lower or higher.

Table A-1: Hydrogen Production Cost Comparisons from Various Sources

Resource	Technology	Efficiency (%HHV)	Cost ($/MMBtu)	Notes	Estimated Timeframe	Data Source	Notes
Coal	Gasification/Shift/PSA	63	6.83	Current Technology No Sequestration	Current	Mitretek (1)	1,2,3
		-	6.20	"	"	Williams (2)	4
	Gasification/Shift/PSA	59	8.18	Current Technology Sequestration	2005+	Mitretek (1)	
		-	7.90	"	"	Williams (2)	5
		60	6.91	"	"	Parsons (3)	
	Advanced Gasification/Shift/PSA	62	5.42	Co-production of Hydrogen & Power No Sequestration	2005	Mitretek (1)	
	Advanced Gasification/Shift/PSA	56	5.64	Co-production of Hydrogen & Power Sequestration	2015+	Mitretek (1)	
	Advanced Gasification/Membrane Separation	59	3.98	Co-production of Hydrogen & Power Sequestration	2015+	Mitretek (1)	6
	Advanced Gasification/Membrane Separation	75	5.89	Production of Hydrogen Sequestration	2015+	Mitretek (1)	
		80	5.06	"	2015+	Parsons (3)	
	Advanced Gasification/SOFC/ Membrane Separation	65	2.40	Co-production of Hydrogen & Power Sequestration	2020+	Mitretek (1)	7

Resource	Technology	Efficiency (%HHV)	Cost ($/MMBtu)	Notes	Estimated Timeframe	Data Source	Notes
Coal	Water Electrolysis from electric power derived from Advanced IGCC	40	14.00	No sequestration	2005	Mitretek (1)	
	Water Electrolysis from electric power derived from Advanced IGCC	35	17.50	Sequestration	2015+	Mitretek (1)	
Petroleum Coke	Current Gasification/Shift/PSA	54	4.50	Co-production of Hydrogen & Power No Sequestration	Current	Mitretek (4)	8
Natural Gas	Steam Methane Reforming (SMR)/PSA	83	5.54	Includes export steam No Sequestration	Current	Parsons (3)	9
Natural Gas	Steam Methane Reforming (SMR)/PSA	78	5.93	Sequestration	2015+	Parsons (3)	10
Natural Gas	ITM Synthesis Gas Generation, Advanced Membrane Separation, CO_2 capture		4.15	Sequestration	2015+	FE Hydrogen Program Plan Goal	11
Gravity	Hydropower Water electrolysis	-	21.90	Hydropower capital cost of $3260/kW		Ogden (5)	12
Nuclear	Water electrolysis	-	14.50	Assuming capital cost of nuclear $1620/kW		Ogden (5)	13
	Sulfur-Iodine cycle	45-55	9.70	Preliminary estimate	2020+	General Atomics (6)	14
Biomass	Gasification	-	9 – 18	Feedstock cost range: $1.0 - $2.7 per MMBtu		NREL Survey (7)	
	Pyrolysis to bio-oil/Steam reforming	-	9.4 – 16.3	Bio-oil cost of $7.1 per MMBtu		NREL Survey (7)	
Wind	Wind Water electrolysis	-	21	1998 estimate for the year 2000	Current	NREL Survey (7)	

Resource	Technology	Efficiency (%HHV)	Cost ($/MMBtu)	Notes	Estimated Timeframe	Data Source	Notes
Wind	Wind Water electrolysis	-	11.6	Assumes technology improvements that will reduce the cost	2010	NREL Survey (7)	
Geothermal	Geothermal Water electrolysis	-	25 – 45	Based on current electricity cost of 5 to 8 cents/kWh	Current	EERE/TMS estimates (8)	15
	Geothermal Water electrolysis	-	13 – 15	Based on electricity cost of 3 cents/kWh	2010+	EERE/TMS estimates (8)	16
Sunlight	Photovoltaics Water electrolysis	-	44	1998 estimate for the year 2000	Current	NREL Survey (7)	
	Photovoltaics Water electrolysis	-	26	Assumes technology improvements that will reduce the cost	2010	NREL Survey (7)	
	Concentrated Solar Water electrolysis	-	43 – 68	Ambient Temperature Electrolysis	2010	Glatzmaier et al, 1998 (9)	
Sunlight	Concentrated Solar Water electrolysis	-	36 – 64	Ambient Temperature Electrolysis	2020	Glatzmaier et al, 1998 (9)	
	Concentrated Solar Water electrolysis	-	52 – 66	High-Temperature Electrolysis		Glatzmaier et al, 1998 (9)	
Water and Sunlight	Photobiological - Algal growth process	-	10.6	Highly speculative preliminary estimate	2020+	Benemann (10)	
Secondary Electricity	Electrolysis	-	10 – 13	Electricity cost at 2 cents/kWh	Current	NREL Survey (7)	17
	Electrolysis	-	19 – 22	Electricity cost at 4 cents/kWh	Current	NREL Survey (7)	17
	Electrolysis	-	41 – 45	Electricity cost at 8 cents/kWh	Current	NREL Survey (7)	17

Data Source:

1) Hydrogen from Coal, Mitretek Technical Paper MTR 2002-31, July 2002

2) Hydrogen Production Costs with Alternative Technologies, Robert H. Williams, Princeton Environmental Institute, Presentation, Washington, D.C. July 17, 2002

3) Hydrogen Production Facilities Plant Performance and Cost Comparisons, Parsons Infrastructure and Technology Group, Final Report, March 2002

4) Opportunities for Petroleum Coke Gasification under Tighter Sulfur Limits for Transportation Fuels, Mitretek Paper MP 2000-61, December 2000

5) Ogden, Joan, M. & Williams, Robert. H., Solar Hydrogen, Moving Beyond Fossil Fuels, World Resources Institute Report, October 1989.

6) Schultz, Ken, General Atomics, Economic Production of Hydrogen from Nuclear Energy, Presentation to DOE, September 2002.

7) Padro, C.E.G. & Putsche, V., National Renewable Energy Laboratory, Survey of the Economics of Hydrogen Technologies, Technical Report, September 1999.
    a. Note: This survey includes information from the following sources: Larson, 1992; Mann et al, 1995; Mann et al, 1998; Andreassen 1998.

8) EERE Geothermal Program Website (http://www.eren.doe.gov/geothermal/); Williams, Hydrogen Production Costs with Alternative Technologies, 2002; and Technology & Management Services, Inc., Hydrogen Production Cost Comparison Spreadsheet Estimates, 2002.

9) Glatzmaier, Greg (Peak Design), Blake, Dan (National Renewable Energy Laboratory), & Showalter, Steve (Sandia National Laboratory), Assessment of Methods for Hydrogen Production Using Concentrated Solar Energy, January 1998.

10) Benemann, John R., Consultant, Process Analysis and Economics of Biophotolysis of Water, IEA Report, March 1998.

Notes:

1) Coal cost is $29/ton (and is assumed to de-escalate at 1.5 percent below general inflation) and the assumed plant capacity factor is 85 percent.

2) For those cases with no sequestration, the co-produced power value is assumed to be \$35.6/MWh, based on the cost of power production from Natural Gas Combined-Cycle (NGCC) plants if natural gas costs \$3.75/MMBtu. In cases where there is carbon sequestration, the co-produced power is assumed to have a value of \$53.6/MWh, based on an additional cost of power production from Natural Gas Combined-Cycle (NGCC) plants with sequestration of 18 mills/kWh (reference EPRI report 1000316).

3) For cases with sequestration, it is assumed that \$10 per ton of carbon is added for sequestration after the concentrated carbon dioxide stream has been isolated and the carbon dioxide stream is compressed to 200 bars.

4) Coal cost is \$0.95/ MMBtu (\$20/ton with coal at 20.8 MMBtu/ton).

5) Coal cost is \$0.95/MMBtu. Includes carbon dioxide capture and disposal cost of \$1.70/million, but excludes reported H2 storage cost of \$0.43/MMBtu (for consistency with Mitretek reported costs).

6) Assumes ceramic membrane hydrogen separation device operating at 600 degrees Centigrade.

7) Assumes operation of a solid oxide fuel cell (SOFC) topping cycle operating at 2,000 degrees Fahrenheit with an efficiency of 60 percent with a capital cost of the SOFC stack at \$400/kW.

8) Assumes current gasification with pet coke at \$10 per ton.

9) Assumes natural gas cost of \$3.15/MMBtu.

10) Assumes carbon dioxide capture by Amine Process.

11) Based upon a natural gas price of \$3.15/MMBtu. Hydrogen costs will increase or decrease from this value as natural gas price fluctuates above or below \$3.15/MMBtu.

12) Capacity factor for hydropower assumed to be 47 percent.

13) Assumed capacity factor for nuclear of 65 percent.

14) Based on using 800 degrees Centigrade nuclear heat for the sulfur-iodine water splitting cycle.

15) Based on current geothermal electricity cost of 5 to 8 cents/kWh and electrolysis cost estimates from NREL survey.

16) Based on future geothermal electricity cost estimate from EERE and electrolysis cost estimates from NREL survey.

17) Based on a plant size of 50 - 250 million standard cubic feet of hydrogen produced per day.

HYDROGEN FROM FOSSIL FUEL — BENEFITS SENSITIVITY CASE

The benefits of using hydrogen from fossil fuel in advanced hydrogen powered fuel cell vehicle (FCV) technology are discussed throughout the FE Hydrogen Program Plan with specific impacts shown in Table 2. These benefits are based on Argonne National Laboratory's GREET 1.5a model assumption that long-term fuel cell vehicles (FCVs) will use one third the energy per mile driven as future internal combustion engine (ICE) vehicles. As a sensitivity case, an analysis has been made to assess the impact if FCVs use only one half the energy per mile driven as future ICE vehicles. Table A-2 below provides a summary of that analysis. The table shows that, even at twice the efficiency of future ICE vehicles, compared to Table 2 in which FCV efficiency is three times an ICE vehicle, centrally-produced hydrogen from natural gas and coal used in light-duty FCVs provides significant benefits.

Table A-2: Impact of Centrally-Produced Hydrogen from Natural Gas and Coal and Use in Light-Duty FCVs that are Twice as Efficient as ICE Vehicles in the Long Term (a)

	Hydrogen from Coal		**Hydrogen from Natural Gas**	
Number of Light Duty FCVs	50 million	100 million	50 million	100 million
Number of Hydrogen Plants	117	233	111	221
Hydrogen Production, million short tons per year	15.1	30.3	15.1	30.3
Capital Cost of Hydrogen Plants; $ billion (current dollars)	50	99	16	31
Emissions Reductions				
SO_x, thousand tonnes per year	10	19	26	52
NOx, thousand tonnes per year	28	55	12	25
PM10, thousand tonnes per year	17	33	7	14
CO_2, million tonnes per year (no sequestration)	69	139	144	288
CO_2, million tonnes per year (with sequestration)	264	528	238	476
Other Impacts				
Energy Savings, $ billion per year (current dollars)	16	32	8	16
Reduce Petroleum Imports, million barrels per day	1.5	3.0	1.5	3.0
Natural Gas Displaced trillion cubic feet per year	0.8 decrease	1.6 decrease	1.5 increase	3.1 increase

(a) Based on a system analysis from a central hydrogen plant, pipeline delivery of hydrogen to refueling stations and use in efficient FCVs, compared with oil refining, delivery of gasoline and use in ICE vehicles.

Table A-2 Sources:
Argonne National Laboratory GREET 1.5a model, Per-Mile Fuel-Cycle Energy Use and Emissions for long-term technology light duty vehicles, assumed to be 55% passenger cars, 25% Light Duty Truck Class 1, and 20% Light Duty Truck Class 2. The GREET 1.5a model provides Btu/mile use of energy, broken down by fossil energy, petroleum energy and non-fossil energy, and SOx, NOx, and PM10, among other emissions, on a fuel-cycle basis. Except for the hydrogen from coal plant analysis, and adjusting FCV efficiency to twice instead of three times ICE efficiency in the model, GREET 1.5a assumptions were used in the above table.

Hydrogen from Coal, Mitretek Technical Paper, MTR 2002-31, July 2002. This case is also used in this Office of Fossil Energy Hydrogen from Natural Gas and Coal Program Plan as Case 2 in Table 4. This case defines the quantity of coal, and therefore carbon used to produce hydrogen.

SAIC, March 2003 presentation, which indicates advanced Coal fired IGCC plants emit 0.09 lbs NOx/MMBtu of coal, and 0.08 lbs of SO2/MMBtu at 98 percent recovery. Estimates used in the above analysis assume SO_2 recovery is 99 percent with emission of only 0.04 lbs SO_2/MMBtu through more severe operation of a Rectisol unit.

Hydrogen Production Facilities Plant Performance and Cost Comparisons, Parsons Infrastructure and Technology Group, Final Report, March 2002. Use of current Steam Methane Reforming Technology case. This case defines the quantity of natural gas, and therefore carbon used to produce hydrogen. Both the Parsons and GREET 1.5a natural gas to hydrogen energy efficiency were essentially identical, the GREET 1.5a assumptions were selected for use.

ATTACHMENT A

FREEDOMCAR AND VEHICLE TECHNOLOGIES – 2011 UPDATES

SOURCE: WIKIPEDIA, THE FREE ENCYCLOPEDIA

FreedomCAR and Vehicle Technologies

From Wikipedia, the free encyclopedia

President George W. Bush and Secretary of Energy Sam Bodman listen to DaimlerChrysler´s Mark Chernoby describing the FedEx Pilot Program Plug-in Hybrid Sprinter during visit to the U.S. Postal Service

The FreedomCAR and Vehicle Technologies (FCVT) is a U.S. national Office of Energy Efficiency and Renewable Energy program developing more energy efficient and environmentally friendly highway transportation technologies that will enable the U.S to use less petroleum. The long-term aim is to develop "leap frog" technologies that will provide Americans with greater freedom of mobility and energy security, while lowering costs and reducing impacts on the environment.

Contents

FCVT Office

The Office of FreedomCAR and Vehicle Technologies (FCVT) is in the Department of Energy (DoE).

Clean Cities Program

The Clean Cities Program is part of the Office of Energy Efficiency and Renewable Energy's FreedomCAR & Vehicle Technologies Program.

The mission of Clean Cities is to advance the nation's economic, environmental, and energy security by supporting local decisions to adopt practices that contribute to the reduction of petroleum consumption. Clean Cities carries out this mission through a network of more than 80 volunteer coalitions, which develop public and private partnerships to promote alternative fuels and vehicles, fuel blends, fuel economy, hybrid vehicles, and idle reduction.

Partnerships

The goal of the **FreedomCAR and Fuel Partnership** is the development of emission- and petroleum-free cars and light trucks. The Partnership focuses on the high-risk research needed to develop the necessary technologies, such as fuel cells and advanced hybrid propulsion systems, to provide a full range of affordable cars and light trucks that are free of foreign oil and harmful emissions — and that do not sacrifice freedom of mobility and freedom of vehicle choice.

To address the research and development needs of commercial vehicles, the goal of the **21st Century Truck Partnership** is for USA trucks and buses to safely and cost-effectively move larger volumes of freight and greater numbers of passengers while emitting little or no pollution, with dramatic reduction in dependence on imported petroleum.

FreedomCAR and plug-in hybrids

Main article: Plug-in hybrid

In 2007 DOE announced that it will invest nearly $20 million in plug-in hybrid electric vehicle (PHEV) research. PHEVs have the potential to displace a large amount of gasoline by delivering up to 40 miles of electric range without recharging—a distance that includes most daily roundtrip commutes. Five projects will be cost-shared with the United States Advanced Battery Consortium (USABC), allowing up to $38 million for battery research and development. The five lithium ion battery companies selected for the projects include [1]:

- EnerDel, Inc.[2] of Indianapolis, Indiana– selected for an award of up to $1.25 million from DOE (total DOE/industry cost share: $2.5 million) over two years to develop cells for 10- and 40-mile range PHEVs using nanophase lithium titanate coupled with a high voltage Nickel-Manganese cathode material;[3]
- A123Systems of Watertown, Massachusetts; Compact Power Inc. in Michigan, selected for an award of up to $6.25 million from DOE (total DOE/industry cost share: $12.5 million) over three years for a project to develop batteries based on nanophase iron-phosphate chemistry for 10- and 40-mile range PHEVs;
- Compact Power Inc. of Troy, Michigan, selected for an award of up to $4.45 million from DOE (total DOE/industry cost share: $12.7 million) over three years to develop batteries for 10-mile range PHEVs using high energy and high power Manganese-spinel;
- 3M in Saint Paul, Minnesota, selected for an award of up to $1.14 million from DOE (total DOE/industry cost share: $ 2.28 million) over two years to screen nickel/manganese/cobalt (NMC) cathode materials through building and testing of small-sized cells;
- and Johnson Controls – Saft Advanced Power Solutions of Milwaukee of Wisconsin, WI, selected for an award of up to $4.1 million from DOE (total DOE/industry cost-share: $8.2 million) over two years to develop batteries using a nickelate/layered chemistry for 10- and 40-mile range PHEVs.

The projects will focus on developing batteries and cells for 10- and 40-mile range PHEVs and building small cells to test new cathode materials.

In addition, the University of Michigan will receive nearly $2 million to explore the future of PHEVs in a two-year study conducted with DOE's Pacific Northwest National Laboratory (PNNL), General Motors, Ford Motor Company, and DTE Energy. The study will evaluate how PHEVs would share the power grid with other energy needs; monitor the American public's view of PHEVs and their driving behavior in such vehicles; assess the reduction of greenhouse gas emissions; and identify how automakers can optimize PHEV design to increase performance and reduce cost. See the DOE press release, the PNNL press Release, and the Draft Plug-In Hybrid Electric Vehicle R&D Plan on the FreedomCAR and Vehicle Technologies Program Web site.

A number of other efforts are also aiming to advance PHEV technologies. In early September, Google.org—the philanthropic arm of Google Inc.—offered $10 million to for-profit companies that are working to advance PHEV technologies. Meanwhile, California's Pacific Gas and Electric Company (PG&E) announced that it is working with Tesla Motors to study the remote control of the charging of electric vehicles. Such "smart charging" could allow a utility to vary the electric charging load on its system in response to intermittent energy sources. In effect, electric vehicles would serve as a large energy storage system that utilities could direct energy to at times when ample supplies are available and the load on the electrical grid is low.

Also DOE and China's Ministry of Science and Technology (MOST) signed a five-year agreement in September 2007 to support the large-scale deployment of electric and hybrid-electric vehicles in both countries.[4]

Criticisms

With the hydrogen-focused FCVT, whose goal is decades away, the Bush Administration was criticized for ignoring any intermediate-term solutions, while funding it largely with monies redirected from other renewable-energy and energy-efficiency programs.[5] As Ashok Gupta, the lead energy economist at the Natural Resources Defense Council, put it, "The FreedomCAR is really about Bush's freedom to do nothing about cars today."[6]

Reduction in 2010 funding

The Department of Energy's congressional budget request for 2010 budget cuts funding for fuel cell technologies by 60% to 70 million USD.[7] Secretary of Energy Steven Chu's presentation portrays this as "moving away from funding vehicular hydrogen fuel cells to technologies with more immediate promise."[8]

See also

- Air car
- CAFE

- Michigan Memorial Phoenix Energy Institute
- Plug-in hybrid
- PHEV Research Center
- Low-energy vehicle

References

1. ^ Department of Energy - DOE to Provide up to $14 Million to Develop Advanced Batteries for Plug-in Hybrid Electric Vehicles (http://www.energy.gov/news/4926.htm)
2. ^ Department of Energy - DOE to Provide Nearly $20 Million to Further Development of Advanced Batteries for Plug-in Hybrid Electric Vehicles (http://www.doe.gov/news/5523.htm)
3. ^ EnerDel Receives Positive Results in Independent Tests on Company's Lithium-Ion Automotive Battery System (http://www.electricdrive.org/index.php?tg=entry&idx=more&article=1804&idg=1)
4. ^ Department of Energy - U.S. and China Continue to Increase Cooperation on Vehicle Efficiency (http://www.energy.gov/news/5518.htm)
5. ^ What can we learn from Bush's FreedomCar Plan? (http://www.grist.org/news/powers/2003/02/26/tough/) by Amanda Griscom Little at Grist.org (http://www.grist.org) , 2003-02-26, retrieved 2009-05-13
6. ^ *ibid*
7. ^ DOE Budget highlights (http://www.cfo.doe.gov/budget/10budget/Content/Highlights/FY2010Highlights.pdf) (PDF), May 2009, retrieved 2009-05-13
8. ^ Secretary Chu's DOE budget presentation (http://www.energy.gov/media/Secretary_Chu_2010_Budget_rollout_presentation.pdf) (PDF) slide 7, 2009-05-07, retrieved 2009-05-13

External links

- FreedomCAR and Vehicle Technologies (FCVT) Program (http://www1.eere.energy.gov/vehiclesandfuels/) - USA Department of Energy FreedomCAR and Vehicle Technologies (FCVT) Program website.
- 21st Century Truck Partnership (http://www1.eere.energy.gov/vehiclesandfuels/about/partnerships/21centurytruck/index.html)
- Clean Cities (http://www.eere.energy.gov/cleancities/) .

FreedomCAR plug-ins

- DOE press release (http://www.energy.gov/news/5523.htm)
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    - Draft Plug-In Hybrid Electric Vehicle (PHEV) R&D Plan (http://www1.eere.energy.gov/vehiclesandfuels/pdfs/program/phev_rd_plan_june_2007.pdf) .
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Retrieved from "http://en.wikipedia.org/wiki/FreedomCAR_and_Vehicle_Technologies"
Categories: Energy in the United States

- This page was last modified on 9 August 2010 at 19:02.
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ATTACHMENT B

FOSSIL FUEL REFORMING – 2011 UPDATES

SOURCE: WIKIPEDIA, THE FREE ENCYCLOPEDIA

Fossil fuel reforming

From Wikipedia, the free encyclopedia

Fossil fuel reforming is a method of producing hydrogen or other useful products from fossil fuels such as natural gas. This is achieved in a processing device called a reformer which reacts steam at high temperature with the fossil fuel. The steam methane reformer is widely used in industry to make hydrogen. There is also interest in the development of much smaller units based on similar technology to produce hydrogen as a feedstock for fuel cells.[1] Small-scale steam reforming units to supply fuel cells are currently the subject of research and development, typically involving the reforming of methanol or natural gas[2] but other fuels are also being considered such as propane, gasoline, autogas, diesel fuel, and ethanol.[3]

During the conversion of the fossil fuel into hydrogen, carbon is released into the atmosphere, typically as carbon dioxide.[4] As a result, fuel cell systems using reformed fossil fuels would emit substantial amounts of carbon dioxide, so would not make much contribution to reducing carbon dioxide emissions, as is expected to be necessary to tackle global warming.

Contents

History

- 1923 - The first synthetic methanol was produced by BASF in Leuna making use of hydrogen derived from lignite.

Industrial reforming

Main article: Methane reformer

Steam reforming of natural gas or syngas sometimes referred to as steam methane reforming (SMR) is the most common method of producing commercial bulk hydrogen as well as the hydrogen used in the industrial synthesis of ammonia. It is also the least expensive method.[5] At high temperatures (700 – 1100 °C) and in the presence of a metal-based catalyst (nickel), steam reacts with methane to yield carbon monoxide and hydrogen. These two reactions are reversible in nature.

$$CH_4 + H_2O \rightarrow CO + 3\ H_2$$

Additional hydrogen can be recovered by a lower-temperature gas-shift reaction with the carbon monoxide produced. The reaction is summarized by:

$CO + H_2O \rightarrow CO_2 + H_2$

The first reaction is strongly endothermic (consumes heat), the second reaction is mildly exothermic (produces heat).

The United States produces nine million tons of hydrogen per year, mostly with steam reforming of natural gas. The worldwide ammonia production, using hydrogen derived from steam reforming, was 109 million metric tonnes in 2004.[6]

This SMR process is quite different from and not to be confused with catalytic reforming of naphtha, an oil refinery process that also produces significant amounts of hydrogen along with high octane gasoline.

The efficiency of the process is approximately 65% to 75% [1] (http://www.getenergysmart.org/files/hydrogeneducation/6hydrogenproductionsteammethanereforming.pdf) </ref>[*citation needed*].

Advantages of reforming for supplying fuel cells

Steam reforming of gaseous hydrocarbons is seen as a potential way to provide fuel for fuel cells. The basic idea for vehicle on-board reforming is that for example a methanol tank and a steam reforming unit would replace the bulky pressurized hydrogen tanks that would otherwise be necessary. This might mitigate the distribution problems associated with hydrogen vehicles.,[7] however the major market players discarded the approach of on-board reforming as unpractical.

Disadvantages of reforming for supplying fuel cells

The reformer–fuel-cell system is still being researched but in the near term, systems would continue to run on existing fuels, such as natural gas or gasoline or diesel. However, there is an active debate about whether using these fuels to make hydrogen is beneficial while global warming is an issue. Fossil fuel reforming does not eliminate carbon dioxide release into the atmosphere but reduces the carbon dioxide emissions as compared to the burning of conventional fuels due to increased efficiency.[8]

The cost of hydrogen production by reforming fossil fuels depends on the scale at which it is done, the capital cost of the reformer and the efficiency of the unit, so that whilst it may cost only a few $ per kg of hydrogen at industrial scale, it could be more expensive at the smaller scale needed for fuel cells.[9]

Current problems with reformers supplying fuel cells

However, there are several challenges associated with this technology:

- The reforming reaction takes place at high temperatures, making it slow to start up and requiring costly high temperature materials.
- Sulfur compounds present in the fuel poison certain catalysts, making it difficult to run this type of system from ordinary gasoline. Some new technologies have overcome this challenge, however, with sulfur-tolerant catalysts.
- Low temperature polymer fuel cell membranes can be poisoned by the carbon monoxide (CO) produced by the reactor, making it necessary to include complex CO-removal systems. Solid oxide fuel cells (SOFC) and Molten carbonate fuel cells (MCFC) do not have this problem, but operate at higher temperatures, slowing start-up time, and requiring costly materials and bulky insulation.
- The thermodynamic efficiency of the process is between 70% and 85% (LHV basis) depending on the purity

of the hydrogen product.

- The biggest problem for reformer based systems remains the fuel cell itself, in terms of both cost and durability. The catalyst used in the common polymer-electrolyte-membrane fuel cell, the device most likely to be used in transportation roles, is very sensitive to any leftover carbon monoxide in the fuel, which some reformers do not completely remove. The anode catalyst is poisoned by the carbon monoxide and the fuel cells performance degrades.
- The catalyst in low temperature fuel cells is based on platinum, and is hence very expensive. A typical automotive fuel cell stack prototype (100 kW) contains 20-30g of platinum metal in the form of nano-particles supported on carbon black.

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External links

- "New catalyst boosts hydrogen as transport fuel" (http://www.guardian.co.uk/environment/2008/aug/21/biofuels.travelandtransport) . By Alok Jha. August 21, 2008. *The Guardian*.
- "Hydrogen Production - Steam Methane Reforming (SMR)" (http://www.getenergysmart.org/Files/HydrogenEducation/6HydrogenProductionSteamMethaneReforming.pdf)

See also

- Biogas
- Cracking (chemistry)
- Hydrogen pinch
- Hydrogen technologies
- Lane hydrogen producer
- PROX
- Reformer sponge iron cycle
- Timeline of hydrogen technologies

Retrieved from "http://en.wikipedia.org/wiki/Fossil_fuel_reforming"
Categories: Hydrogen production | Chemical engineering | Fuel gas | Catalysis

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ATTACHMENT C

FUTUREGEN – 2011 UPDATE

SOURCE: WIKIPEDIA, THE FREE ENCYCLOPEDIA

FutureGen

From Wikipedia, the free encyclopedia
(Redirected from Futuregen)

FutureGen is a US government project announced by President George W. Bush in 2003;[1] its initial plan involved the construction of a near zero-emissions coal-fueled power plant to produce hydrogen and electricity while using carbon capture and storage.[2]

In December 2007, Mattoon Township, Coles County, Illinois northwest of Mattoon, Illinois was chosen as the site for the plant from among four finalists in Illinois and Texas. On January 29, 2008, the Department of Energy announced a restructuring of the FutureGen project, which was claimed necessary due to rising costs.[3] In June 2008, the government announced a call for proposals to elicit commercial involvement in the restructuring.[4][5] In 2010, after a number of setbacks, the city of Mattoon backed out of the project.[6]

Contents

[hide]

[edit]Original project

The original incarnation of FutureGen was as a public-private partnership to build the world's first near zero-emissions coal-fueled power plant. The 275-megawatt plant would be intended to prove the feasibility of producing electricity and hydrogen from coal while capturing and permanently storing carbon dioxide underground. The Alliance intended to build the plant in Mattoon Township, Coles County, Illinois northwest of Mattoon, Illinois, subject to necessary approvals (issuing a “Record of Decision”) by the Department of Energy (DOE) as part of the National Environmental Policy Act (NEPA) process.[7]

FutureGen was to be designed, developed and operated by the FutureGen Industrial Alliance, a non-profit consortium of coal mining and electric utility companies formed to partner with the DOE on the FutureGen project. The project was still in the development stage when its funding was cancelled in January 2008. The Alliance decision of the location of the host site, subject to DOE's completing NEPA environmental reviews, was announced in December 2007 after a two-year bidding and review process. Construction was scheduled to begin in 2009, with full-scale plant operations to begin in 2012.[8]

The estimated gross project cost, including construction and operations, and excluding offsetting revenue, was $1.8 billion. The project was governed by a legally binding cooperative agreement between DOE and the Alliance.[9] Under the agreement, DOE was to provide 74% of the project’s cost, with private industry contributing the other 26%. The DOE also planned to solicit the financial support and participation of international governments in the FutureGen project, since by 2020 more than 60% of man-made greenhouse gas emissions are expected to come from developing countries. Foreign financial support was to offset a portion of DOE’s cost-share. As of January 2008, the foreign governments of China, India, Australia, South Korea, and Japan had expressed interest in participating and sharing the cost of the project.[10]

FutureGen was to sequester carbon dioxide emissions at a rate of one million metric tons per year for four years, which is the scale a Massachusetts Institute of Technology (MIT) report cites as appropriate for proving sequestration. The MIT report also states that “the priority objective with respect to coal should be the successful large-scale demonstration of the technical, economic, and environmental performance of the technologies that make up all of the major components of a large-scale integrated CCS system — capture, transportation and storage.”[11] An injection field test similar to this was done in Norway.[12][13]

In March 2009 Washington Post reported that U.S. Secretary of Energy Steven Chu expressed support for continuing the project using stimulus funds (after some changes that have not yet been specified) and making it a part of a larger portfolio of research plants developed in collaboration with other countries.[14]

[edit]Alliance members

The FutureGen Industrial Alliance is a consortium of 10 power producers and electric utilities from around the globe.[15]

Company	Headquarters
Anglo American Services (UK) Limited	London, UK
BHP Billiton Energy Coal Inc.	Melbourne, Australia
Caterpillar Inc.	Peoria, Illinois
China Huaneng Group	Beijing, China
CONSOL Energy Inc.	Pittsburgh, Pennsylvania
E.ON U.S. LLC	Louisville, Kentucky
Foundation Coal Corporation	Linthicum Heights, Maryland
Peabody Energy Corp.	St. Louis, Missouri
Rio Tinto Energy America Services	Gillette, Wyoming
Xstrata Coal Pty Limited	Sydney, Australia

[edit]Former members

Four companies initially a part of the FutureGen Industrial Alliance have since dropped out of the project.

Company	Headquarters
American Electric Power Service Corp. [16]	Columbus, Ohio
Luminant [17]	Dallas, Texas
PPL Energy Services Group, LLC [17]	Allentown, Pennsylvania
Southern Company Services, Inc. [16]	Atlanta, Georgia

[edit]Site selection

Site selection for the FutureGen facility was based on a competitive process which began in May 2006. Seven states responded[18] to the Site Request for Proposals with a total of 12 proposals. Proposals were reviewed against a set of environmental, technical, regulatory, and financial criteria with input from external technical advisors on power plant design andcarbon sequestration. In July 2006, four candidate sites were selected for further review, including an environmental impact analysis as required by NEPA.

DOE issued its Final Environmental impact statement (EIS) on November 8, 2007, which concluded that all four sites were acceptable from an environmental impact standpoint and all would move forward in the site evaluation process. EPA published a Notice of Availability (NOA) for the EIS in the Federal Register on November 16, 2007.[19] The DOE is required by federal law to wait at least 30 days after the NOA release before issuing its final Record of Decision (ROD). The waiting period legally closed on December 17, 2007. DOE chose not to issue the ROD and advised the FutureGen Alliance to delay the final site selection announcement, which was scheduled to occur at the end of the 30-day waiting period. The Alliance chose to move ahead with the announcement, citing time, money, and a commitment to proposers to select the final site by year-end. "Every month of delay can add $10 million to the project's cost, solely due to inflation," said Michael Mudd, the Alliance's chief executive.

City	Proposals	Finalists
Effingham, Illinois	x	
Marshall, Illinois	x	
Mattoon, Illinois	**x**	**x**
Tuscola, Illinois	x	x
Henderson County, Kentucky	x	
Bowman County, North Dakota	x	

Meigs County, Ohio	x	
Tuscarawas County, Ohio	x	
Odessa, Texas	x	x
Jewett, Texas	x	x
Point Pleasant, West Virginia	x	
Gillette, Wyoming	x	

The FutureGen Alliance announced the selection of Mattoon, Illinois as the host site on December 18, 2007.[20][21] According to the EIS, Mattoon, IL the site is located about 3.5 miles (5.6 km) northwest of downtown Mattoon in the eastern part of Mattoon township section 8 on 1.8 km^2 (440 acres) of former farm land. The carbon sequestration area is about 8,000 feet (2.4 km) below the ground.[22] In July 2007, Illinois Public Act 095-0018 became law giving the state of Illinois ownership of and liability for the sequestered gases.[23]

Future plants based on FutureGen should qualify for several provisions of the Energy Policy Act of 2005.

[edit]Technology overview

FutureGen was intended to combine and test several new technologies in a single location, including coal gasification, emissions controls, hydrogen production, electricity generation, and carbon dioxide capture and storage (CCS).[24]

Integrated Gasification Combined Cycle (IGCC) was the core technology behind FutureGen. IGCC power plants use two turbines – a gas and a steam turbine – to produce electric power more efficiently than pulverized coal plants. IGCC plants also make it easier to capture carbon dioxide for carbon sequestration.[25]

FutureGen was to capture carbon dioxide produced during the gasification process and pump it into deep rock formations thousands of feet under ground. FutureGen specifically targeted rock formations containing saline water, as these are one of the most abundant types of geologic formations that can be used to store carbon dioxide worldwide.[26] A study by the Global Energy Technology Strategy Program estimates the storage capacity of these saline rock formations in the U.S. to be 2,970 gigatons of carbon dioxide, compared to a capacity of 77 gigatons of carbon dioxide for all other types of reservoirs, such as depleted gas fields.[27] Focusing on rock formations with saline water was intended to help ensure that the lessons learned from the project are broadly transferable throughout the U.S. and around the world.

[edit]Challenges

Maintaining the project schedule and keeping costs down were two major challenges with which the DOE and the FutureGen Alliance grappled. The project had remained on schedule with the announcement of the host site before the end of 2007; however, a desire by DOE to restructure the project’s financial arrangement has brought the project to a halt.

In December 2007, the DOE Acting Deputy Assistant Secretary for Fossil Energy James Slutz stated that projected cost overruns for the project "require a reassessment of FutureGen's design." And that "This will require restructuring FutureGen to maximize the role of private-sector innovation, facilitate the most productive public-private partnership, and prevent further cost escalation."[28]

The FutureGen Alliance wrote a letter to the Department of Energy's Under Secretary C.H. "Bud" Albright Jr. stating that overall inflation and the rising cost of raw materials and engineering services are driving costs up on energy projects around the world. According to James L. Connaughton, chairman of the White House Council on Environmental Quality, the market for steel, concrete and power plant components has "just gone through the roof globally", and much of the reason is the construction of hundreds of new conventional coal plants.[29]

On January 11, 2008, the FutureGen Alliance sent a letter to the DOE offering to lower the government's portion of the project's costs. The initial plans had called for DOE to pay based on a percentage of the total cost, and their portion had risen from about $620 million to about $1.33 billion. The letter indicated that DOE's portion would now be $800 million.[30]

Risk management was a significant portion of the cost of the first FutureGen experimental implementation.[31] FutureGen involved many complex never-before-solved technology problems. The risks also included significant health risks, if the untested-technology systems failed to work correctly.

[edit]DOE decision controversies

[edit]Funding cancellation

On January 29, 2008, the U.S. Department of Energy announced that it would pull its funding for the project, mostly due to higher than expected costs. The move is likely to delay the project as other members seek the additional funds that the DOE was to provide. The sudden concern over cost after an Illinois site was chosen over those in Texas raised questions about the motives for the cancellation. Local and state officials in Illinois, including then Governor Rod Blagojevich, expressed frustration at the move, especially in light of the money and resources that the state had spent to attract the project. Democratic Senator Dick Durbin of Illinois accused Energy Secretary Samuel Bodman of "cruel deception" of Illinoisans by "creating false hope in a FutureGen project which he has no intention of funding or supporting."[32] Durbin claimed that "when the city of Mattoon, Illinois, was chosen over possible locations in Texas, the secretary of energy set out to kill FutureGen." [33] Mattoon mayor David Cline said "one could question the motivation of the Department of Energy which was ready to move forward with the project until a site other than Texas was chosen."[33]

In March 2009, Congressional auditors determined that the DOE had miscalculated the government portion of the project's cost, overstating the amount by a half billion dollars. As a result, the Bush administration cited the project as having nearly doubled in cost when, in reality, it had increased by 39%[34]

Secretary Bodman stated that with restructuring the FutureGen project, DOE plans "to equip multiple new clean-coal power plants with advanced CCS technology, instead of one demonstration plant. That will provide more electricity from multiple clean-coal plants, sequestering at least twice as much CO_2 and providing for wider use and more rapid commercialization."[35]

Despite the cancellation of funding by the DOE, the FutureGen Alliance continues to move forward with the project, opening an office in Mattoon and planning to buy the land for the plant in August 2008, in partnership with a local group.[36][37]

[edit]Revised plan under new presidential administration

During the 2008 U.S. presidential campaigns, Sen. Barack Obama pledged his support to clean coal technologies, with plans to develop five commercial-scale coal plants equipped with CCS technology.[38]

In November 2008, Fred Palmer, senior vice president at Peabody Energy shared his outlook on FutureGen with the American Coalition for Clean Coal Electricity (ACCCE), saying that the FutureGen Alliance would "Make a concerted effort in the Obama administration to reinstate the project and get this built as originally planned." [39]

On June 12, 2009, the DOE announced a restart of design work for the FutureGen project.[40] "Following the completion of the detailed cost estimate and fundraising activities," the press release states, "the Department of Energy and the FutureGen Alliance will make a decision either to move forward or to discontinue the project early in 2010."

On August 5, 2010, the DOE announced a retooling of the FutureGen project, dubbed FutureGen 2.0.[41] The revised plan includes retrofitting a shuttered coal-fired power plant inMeredosia, Illinois to demonstrate advanced oxy-combustion technology, and piping the carbon dioxide 175 miles to Mattoon for underground storage. Due to these changes, leaders in Mattoon decided to drop out of the FutureGen project.[42] The Illinois sites vying for the underground storage portion of the project are in Christian, Douglas, Fayette, and Morgan counties, after sites in Adams and Pike counties were cut in December 2010.[43]

In February 2011, Morgan County IL was chosen for the sequestration site.

[edit]See also

- Clean coal
- Carbon capture and storage
- Combined cycle
- Gasification
- Asia-Pacific Partnership for Clean Development and Climate
- North American Carbon Program

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Categories: Chemical engineering | Climate change in the United States | Proposed coal-fired power stations in the United States | Coles County, Illinois

ATTACHMENT D

INTEGRATED GASIFICATION COMBINED CYCLE – 2011 UPDATE

SOURCE: WIKIPEDIA, THE FREE ENCYCLOPEDIA

Integrated gasification combined cycle

From Wikipedia, the free encyclopedia
(Redirected from Igcc)

An **integrated gasification combined cycle** (**IGCC**) is a technology that turns coal into gas—synthesis gas (syngas). It then removes impurities from the coal gas before it is combusted and attempts to turn any pollutants into re-usable byproducts. This results in lower emissions of sulfur dioxide, particulates and mercury. Excess heat from the primary combustion and generation is then passed to a steam cycle, similarly to a combined cycle gas turbine. This then also results in improved efficiency compared to conventional pulverized coal.

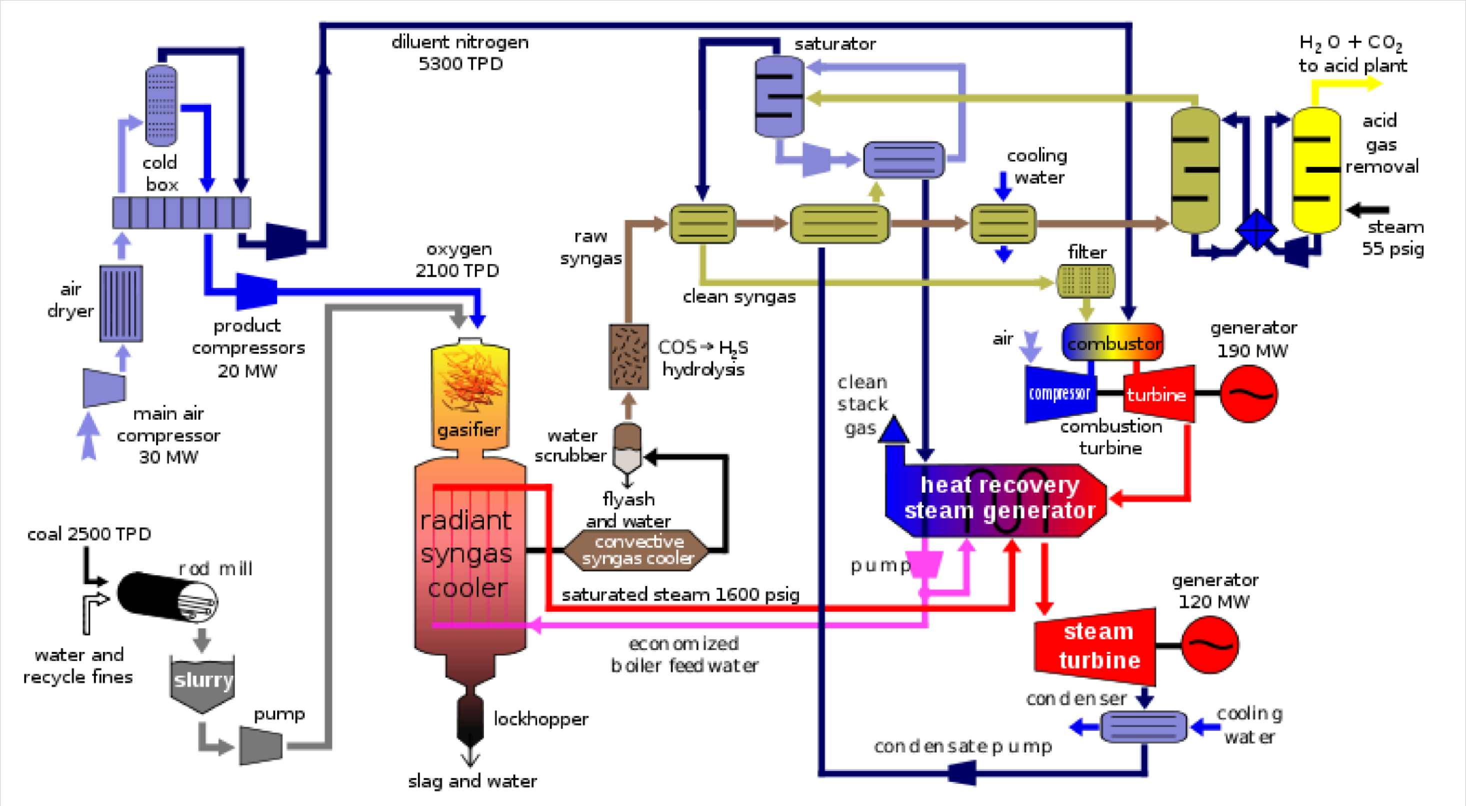
Contents

Significance

Both because it can be found in abundance in America and many other countries and because the price of it has remained relatively constant in recent years, coal is used for about 50 percent of U.S. electricity needs.[1] Thus the lower emissions that IGCC technology allows may be important in the future as emission regulations tighten due to growing concern for the impacts of pollutants on the environment and the globe.[1]

Operations

Below is a schematic flow diagram of an IGCC plant:



Block diagram of IGCC power plant, which utilizes the HRSG

The gasification process can produce syngas from high-sulfur coal, heavy petroleum residues and biomass.

The plant is called *integrated* because its syngas is produced in a gasification unit in the plant which has been optimized for the plant's combined cycle. In this example the syngas produced is used as fuel in a gas turbine which produces electrical power. To improve the overall process efficiency heat is recovered from both the gasification process and also the gas turbine exhaust in 'Waste Heat Boilers' producing steam. This steam is then used in steam turbines to produce additional electrical power.

Installations

In 2007 there were only two IGCC plants generating power in the U.S.;[*citation needed*] however, several new IGCC plants are expected to come online in the U.S. in the 2012-2020 time frame. The DOE Clean Coal (http://www.fossil.energy.gov/programs/powersystems/cleancoal/) Demonstration Project helped construct 3 IGCC plants: Wabash River Power Station in West Terre Haute, Indiana, Polk Power Station in Tampa, Florida (online 1996), and Pinon Pine in Reno, Nevada. In the Reno demonstration project, researchers found that then-current IGCC technology would not work more than 300 feet (100m) above sea level.[2] The DOE report in reference 3 however makes no mention of any altitude effect, and most of the problems were associated with the solid waste extraction system. The plant failed.[3]

Poland's Kędzierzyn will soon host a Zero-Emission Power & Chemical Plant that combines coal gasification technology with Carbon Capture & Storage (CCS). The supplement of up to 10% biomass in the combustion process will make this plant even more environmentally-friendly.

The first generation of IGCC plants polluted less than contemporary coal-based technology, but also polluted water; for example, the Wabash River Plant was out of compliance with its water permit during 1998–2001[4] because it emitted arsenic, selenium and cyanide. The Wabash River Generating Station is now wholly owned and operated by the Wabash River Power Association.

IGCC is now touted as *capture ready* and could potentially capture and store carbon dioxide.[5] (See FutureGen)

There are several advantages and disadvantages when compared to conventional post combustion carbon capture and various variations and these are fully discussed at.[6]

Cost and reliability

The main problem for IGCC is its extremely high capital cost, upwards of $3,593/kW.[7] Official US government figures give more optimistic estimates [8] of $1,491/kW installed capacity (2005 dollars) v. $1,290 for a conventional clean coal facility, but in light of current applications, these cost estimates have been demonstrated to be incorrect.

Outdated per megawatt-hour cost of an IGCC plant vs a pulverized coal plant coming online in 2010 would be $56 vs $52, and it is claimed that IGCC becomes even more attractive when you include the costs of carbon capture and sequestration, IGCC becoming $79 per megawatt-hour vs. $95 per megawatt-hour for pulverized coal.[9] Recent testimony in regulatory proceedings show the cost of IGCC to be twice that predicted by Goddell, from $96 to 104/MWhr.[10][11] That's before addition of carbon capture and sequestration (sequestration has been a mature technology at both Weyburn in the US (for enhanced oil recovery) and Sleipner in the North Sea at a commercial scale for the past ten years)—capture at a 90% rate is expected to have a $30/MWh additional cost.[12]

Wabash River was down repeatedly for long stretches due to gasifier problems, and the gasifier problems have not been remedied—subsequent projects, such as Excelsior's Mesaba Project, have a third gasifier and train built in. However, the past year has seen Wabash River running reliably, with availability comparable to or better than other technologies.

The Polk County IGCC has design problems. First, the project was initially shut down because of corrosion in the slurry pipeline that fed slurried coal from the rail cars into the gasifier. A new coating for the pipe was developed. Second, the thermocoupler was replaced in less than two years; an indication that the gasifier had problems with a variety of feedstocks; from bituminous to sub-bituminous coal. The gasifer was designed to also handle lower rank lignites. Third, unplanned down time on the gasifer because of refractory liner problems, and those problems were expensive to repair. The gasifer design was originally done in Italy for a gasifier smaller by 2 x what was built at Polk. Newer ceramic materials may assist in improving gasifier performance and longevity. Understanding the operating problems of the built IGCC is necessary to design the IGCC of the future. (Polk IGCC Power Plant, http://www.clean-energy.us/projects/polk_florida.html.) Keim, K., 2009, IGCC A Project on Sustainability Management Systmes for Plant Re-Design and Re-Image. Unpublished paper; Harvard University)

General Electric is currently designing an IGCC model plant that should introduce greater reliability. GE's model features advanced turbines optimized for the coal syngas. Eastman's industrial gasification plant in Kingsport, TN uses a GE Energy solid-fed gasifier. Eastman, a fortune 500 company, built the facility in 1983 without any state or federal subsidies and turns a profit.[13][14]

There are several refinery-based IGCC plants in Europe that have demonstrated good availability (90-95%) after initial shakedown periods. Several factors help this performance:

1. None of these facilities use advanced technology (*F* type) gas turbines.
2. All refinery-based plants use refinery residues, rather than coal, as the feedstock. This eliminates coal handling and coal preparation equipment and its problems. Also, there is a much lower level of ash produced in the gasifier, which reduces cleanup and downtime in its gas cooling and cleaning stages.
3. These non-utility plants have recognized the need to treat the gasification system as an up-front chemical processing plant, and have reorganized their operating staff accordingly.

Another IGCC success story has been the 250 MW Buggenum plant in The Netherlands. It also has good availability. This coal-based IGCC plant currently uses about 30% biomass as a supplemental feedstock. The owner, NUON, is paid an incentive fee by the government to use the biomass. NUON is constructing a 1,300 MW IGCC plant in the Netherlands. The Nuon Magnum IGCC power plant will be commissioned in 2011. Mitsubishi Heavy Industries has been awarded to construct the power plant.[15]

A new generation of IGCC-based coal-fired power plants has been proposed, although none is yet under construction. Projects are being developed by AEP, Duke Energy, and Southern Company in the US, and in Europe by ZAK/PKE, Centrica (UK), E.ON and RWE (both Germany) and NUON (Netherlands). In Minnesota, the state's Dept. of Commerce analysis found IGCC to have the highest cost, with an emissions profile not significantly better than pulverized coal. In Delaware, the Delmarva and state consultant analysis had essentially the same results.

The high cost of IGCC is the biggest obstacle to its integration in the power market; however, most energy executives recognize that carbon regulation is coming soon. Bills requiring carbon reduction are being proposed again both the House and the Senate, and with the Democratic majority it seems likely that with the next President there will be a greater push for carbon regulation. The

Supreme Court decision requiring the EPA to regulate carbon (Commonwealth of Massachusetts et al. v. Environmental Protection Agency et al.)[16] also speaks to the likelihood of future carbon regulations coming sooner, rather than later. With carbon capture, the cost of electricity from an IGCC plant would increase approximately 30%. For a natural gas CC, the increase is approximately 33%. For a pulverized coal plant, the increase is approximately 68%. This potential for less expensive carbon capture makes IGCC an attractive choice for keeping low cost coal an available fuel source in a carbon constrained world.

In Japan, electric power companies, in conjunction with Mitsubishi Heavy Industries has been operating a 200 t/d IGCC pilot plant since the early '90s. In September 2007, they started up a 250 MW demo plant in Nakaso. It runs on air-blown (not oxygen) dry feed coal only. It burns PRB coal with an unburned carbon content ratio of <0.1% and no detected leaching of trace elements. It employs not only *F* type turbines but *G* type as well. (see gasification.org link below)

Next generation IGCC plants with CO2 capture technology will be expected to have higher thermal efficiency and to hold the cost down because of simplified systems compared to conventional IGCC. The main feature is that instead of using oxygen and nitrogen to gasify coal, they use oxygen and CO2. The main advantage is that it is possible to improve the performance of cold gas efficiency and to reduce the unburned carbon (char).[*citation needed*]

With a 1300 degrees C class gas turbine it is possible to achieve 42% net thermal efficiency, rising to 45% with a 1500 degree class gas turbine, with CO2 capture. In case of conventional IGCC systems, it is only possible to achieve just over 30% efficiency with a 1300 degree gas turbine.[*citation needed*]

The CO2 extracted from gas turbine exhaust gas is utilized in this system. Using a closed gas turbine system capable of capturing the CO2 by direct compression and liquefication obviates the need for a separation and capture system.[17]

IGCC Emission Controversy

In 2007, the New York State Attorney General's office demanded full disclosure of "financial risks from greenhouse gases" to the shareholders of electric power companies proposing the development of IGCC coal-fired power plants. "Any one of the several new or likely regulatory initiatives for CO_2 emissions from power plants - including state carbon controls, EPA's regulations under the Clean Air Act, or the enactment of federal global warming legislation - would add a significant cost to carbon-intensive coal generation";[18] U.S. Senator Hillary Clinton from New York has proposed that this full risk disclosure be required of all publicly-traded power companies nationwide.[19] This honest disclosure has begun to reduce investor interest in all types of existing-technology coal-fired power plant development, including IGCC.

Senator Harry Reid (Majority Leader of the 2007/2008 U.S. Senate) told the 2007 Clean Energy Summit that he will do everything he can to stop construction of proposed new IGCC coal-fired electric power plants in Nevada. Reid wants Nevada utility companies to invest in solar energy, wind energy and geothermal energy instead of coal technologies. Reid stated that global warming is a reality, and just one proposed coal-fired plant would contribute to it by burning seven million tons of coal a year. The long-term healthcare costs would be far too high, he claimed (no source attributed). "I'm going to do everything I can to stop these plants.", he said. "There is no clean coal technology. There is cleaner coal technology, but there is no clean coal technology."[20]

One of the most efficient ways to treat the H_2S gas from a IGCC plant, is by converting it into sulphuric acid in a wet gas sulphuric acid process wsa process

See also

- Relative cost of electricity generated by different sources

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External links

- Hunstown: Ireland's most efficient power plant (http://www.powergeneration.siemens.com/en/press/pg200303017e/index.cfm) @ Siemens Power Generation website
- Natural Gas Combined-cycle Gas Turbine Power Plants (http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf) Northwest Power Planning Council, New Resource Characterization for the Fifth Power Plan, August 2002
- Combined cycle solar power (http://www.ingenia.org.uk/ingenia/articles.aspx?index=244&print=true)

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Categories: Thermodynamic cycles | Chemical engineering | Power station technology | Energy conversion

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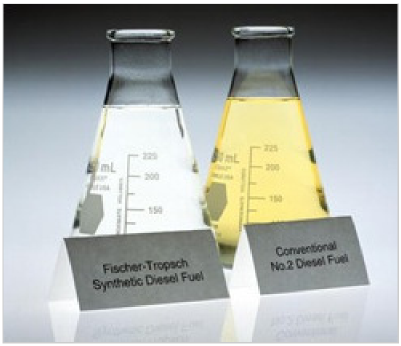
ATTACHMENT E

SYNTHETIC FUEL – 2011 UPDATE

SOURCE: WIKIPEDIA, THE FREE ENCYCLOPEDIA

Synthetic fuel

From Wikipedia, the free encyclopedia



Side-by-side comparison of FT synthetic fuel and conventional fuel. The synthetic fuel is clear as water because of a near-absence of sulfur and aromatics.

Synthetic fuel or **synfuel** is a liquid fuel obtained from coal, natural gas, oil shale, or biomass. It may also refer to fuels derived from other solids such as plastics or rubber waste. It may also (less often) refer to gaseous fuels produced in a similar way. Common use of the term "synthetic fuel" is to describe fuels manufactured via Fischer Tropsch conversion, methanol to gasoline conversion, or direct coal liquefaction.

July 2009 worldwide commercial synthetic fuels production capacity is over 240,000 barrels per day (38,000 m^3/d), with numerous new projects in construction or development.

Contents

Classification and principles

The term 'synthetic fuel' has several different meanings and it may include different types of fuels. More traditional definitions, e.g. definition given by the International Energy Agency, define 'synthetic fuel' as any liquid fuel obtained from coal or natural gas.[1] The Energy Information Administration defines synthetic fuels in its Annual Energy Outlook 2006, as fuels produced from coal, natural gas, or biomass feedstocks through chemical conversion into synthetic crude and/or synthetic liquid products.[2] A number of synthetic fuel's definitions include also fuels produced from biomass, and industrial and municipal waste.[3][4][5] The definition of synthetic fuel may also consist of oil sands and oil shale as synthetic fuel's sources and in addition to liquid fuels also gaseous fuels are covered.[6][7] On his 'Synthetic fuels handbook' a petrochemist James G. Speight included liquid and gaseous fuels as well as clean solid fuels produced by conversion of coal, oil shale or tar sands, and various forms of biomass, although he admits that in the context of substitutes for petroleum-based fuels it has even wider meaning.[7] Depending the context, also methanol, ethanol and hydrogen may be included.[8][9]

Synthetic fuels are produced by the chemical process of conversion.[7] Conversion methods could be direct conversion into liquid transportation fuels, or indirect conversion, in which the source substance is converted initially into syngas which then goes through additional conversion process to become liquid fuels.[2] Basic conversion methods include carbonization and pyrolysis, hydrogenation, and thermal dissolution.[10]

History

See also: Oil Campaign of World War II and Synthetic Liquid Fuels Program

Ruins of the German synthetic petrol plant (Hydrierwerke Pölitz – Aktiengesellschaft) in Police, Poland

Direct conversion of coal to synthetic fuel was originally developed in Germany.[11] The Bergius process was developed by Friedrich Bergius, yielding a patent on the Bergius process in 1913. Karl Goldschmidt invited him to build an industrial plant at his factory the Th. Goldschmidt AG (now known as Evonik Industries) in 1914.[12] The production began only in 1919.[*citation needed*]

Also indirect coal conversion (where coal is gasified and then converted to synthetic fuels) was developed in Germany by Franz Fischer and Hans Tropsch in 1923.[11] During World War II, Germany used synthetic oil manufacturing (German: *Kohleveredelung*) to produce substitute (*Ersatz*) oil products by using the Bergius process (from coal), the Fischer–Tropsch process (water gas), and other methods (Zeitz used the TTH and MTH processes).[13][14] Before World War Two in 1931, the British Department of Scientific and Industrial Research located in Greenwich, England set up a small facility where hydrogen gas at extreme high pressure was combined with coal to make a synthetic fuel. [15]

The Bergius process plants were the primary source of Nazi Germany's high-grade aviation gasoline and the source of most of its synthetic oil, 99% of its synthetic rubber and nearly all of its synthetic methanol, synthetic ammonia, and nitric acid. Nearly 1/3 of the Bergius production was produced by plants in Pölitz (Polish: *Police*) and Leuna, with more than 1/3 more in five other plants (Ludwigshafen had a much smaller Bergius plant[16] which improved "gasoline quality by dehydrogenation" using the DHD process).[14]

Synthetic fuel grades included "T.L. [jet] fuel ", "first quality aviation gasoline", "aviation base gasoline", and "gasoline - middle oil";[14] and "producer gas" and diesel were synthesized for fuel as well (e.g., converted armored tanks used producer gas).[13]:4,s2 By early 1944, German synthetic fuel production had reached more than 124,000 barrels per day (19,700 m^3/d) from 25 plants,[17] including 10 in the Ruhr Area.[18]:239 In 1937, the four central Germany lignite coal plants at Böhlen, Leuna, Magdeburg/Rothensee, and Zeitz, along with the Ruhr Area bituminous coal plant at Scholven/Buer, had produced 4.8 million barrels (760×10^3 m^3) of fuel. Four new hydrogenation plants (German: *Hydrierwerke*) were subsequently erected at Bottrop-Welheim (which used "Bituminous coal tar pitch"),[14] Gelsenkirchen (Nordstern), Pölitz, and, at 200,000 tons/yr[14] Wesseling.[19] Nordstern and Pölitz/Stettin used bituminous coal, as did the new Blechhammer plants.[14] Heydebreck synthesized food oil, which was tested on concentration camp prisoners.[20] The Geilenberg Special Staff was using 350,000 mostly foreign forced laborers to reconstruct the bombed synthetic oil plants,[18]:210,224 and, in an emergency decentralization program, to build 7 underground hydrogenation plants for bombing protection (none were completed). (Planners had rejected an earlier such proposal because the war was to be won before the bunkers would be completed.)[16] In July 1944, the 'Cuckoo' project[21] underground synthetic oil plant (800,000 m^2) was being "carved out of the Himmelsburg" North of the Mittelwerk,[13] but the plant was unfinished at the end of WWII.

Indirect Fischer-Tropsch ("FT") technologies were brought to the US after World War 2, and a 7,000 barrels per day (1,100 m^3/d) plant was designed by HRI, and built in Brownsville Texas. The plant represented the first commercial use of high-temperature Fischer Tropsch conversion. It operated from 1950 to 1955, when it was shut down when the price of oil dropped due to enhanced production and huge discoveries in the Middle East.[11]

After World War Two, in 1949 a demonstration plant for converting coal to gasoline was built and operated by the U.S. Bureau of Mines in Louisiana, Missouri. [22] Direct coal conversion plants were also developed in the US after WW2, including a 3 TPD plant in Lawrenceville, NJ, and a 250-600 TPD Plant in Catlettsburg, KY.[*citation needed*]

Processes

There are numerous processes that can be used to produce synthetic fuels.

These broadly fall into three categories: Indirect, Direct, and Biofuel processes.

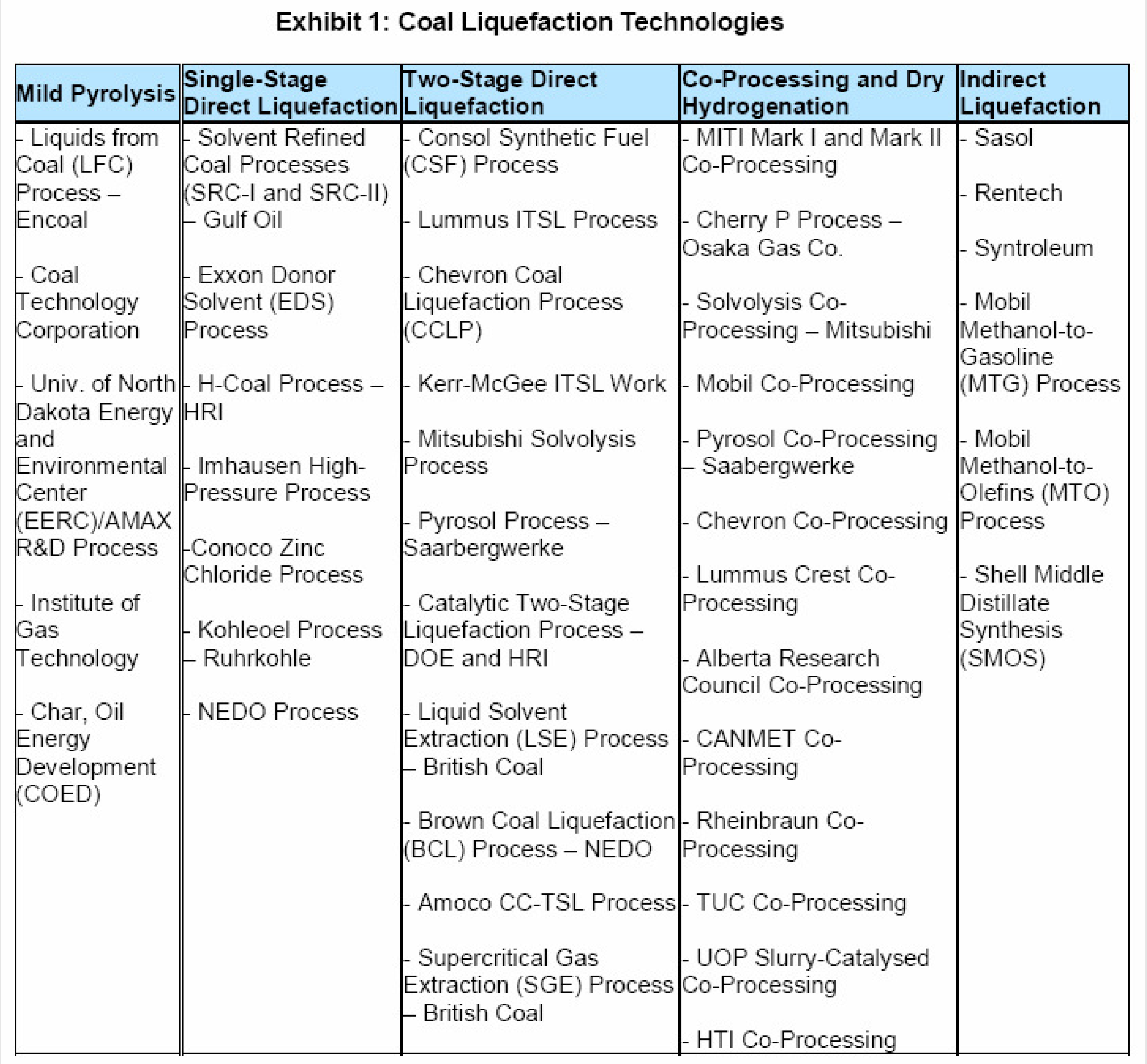


Exhibit 1: Coal Liquefaction Technologies

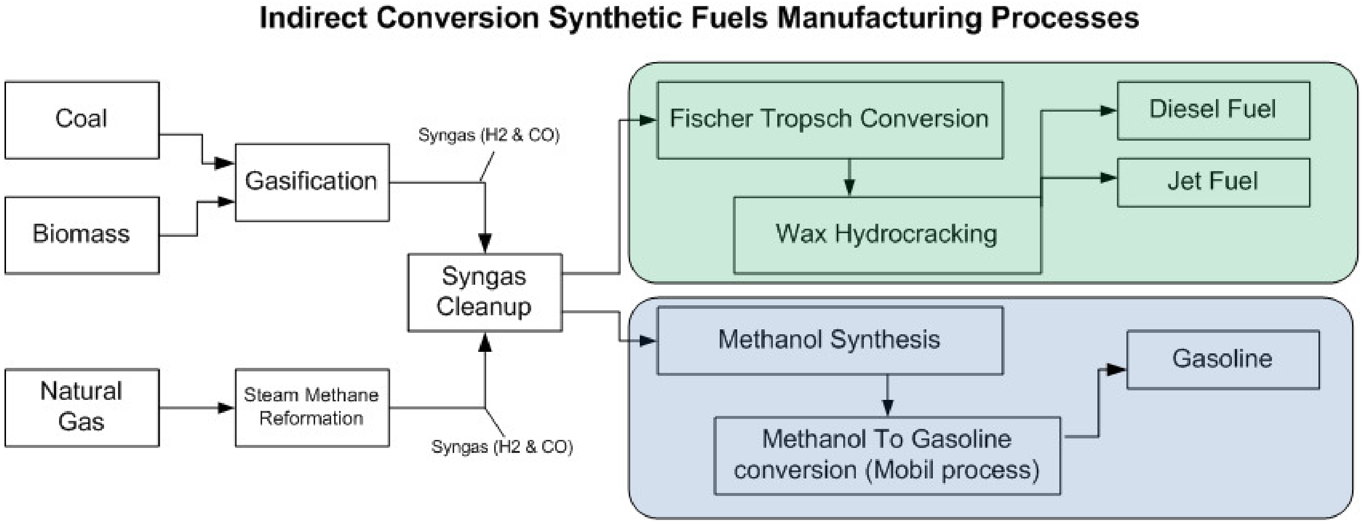
Mild Pyrolysis	Single-Stage Direct Liquefaction	Two-Stage Direct Liquefaction	Co-Processing and Dry Hydrogenation	Indirect Liquefaction
- Liquids from Coal (LFC) Process – Encoal - Coal Technology Corporation - Univ. of North Dakota Energy and Environmental Center (EERC)/AMAX R&D Process - Institute of Gas Technology - Char, Oil Energy Development (COED)	- Solvent Refined Coal Processes (SRC-I and SRC-II) – Gulf Oil - Exxon Donor Solvent (EDS) Process - H-Coal Process – HRI - Imhausen High-Pressure Process -Conoco Zinc Chloride Process - Kohleoel Process – Ruhrkohle - NEDO Process	- Consol Synthetic Fuel (CSF) Process - Lummus ITSL Process - Chevron Coal Liquefaction Process (CCLP) - Kerr-McGee ITSL Work - Mitsubishi Solvolysis Process - Pyrosol Process – Saarbergwerke - Catalytic Two-Stage Liquefaction Process – DOE and HRI - Liquid Solvent Extraction (LSE) Process – British Coal - Brown Coal Liquefaction (BCL) Process – NEDO - Amoco CC-TSL Process - Supercritical Gas Extraction (SGE) Process – British Coal	- MITI Mark I and Mark II Co-Processing - Cherry P Process – Osaka Gas Co. - Solvolysis Co-Processing – Mitsubishi - Mobil Co-Processing - Pyrosol Co-Processing – Saabergwerke - Chevron Co-Processing - Lummus Crest Co-Processing - Alberta Research Council Co-Processing - CANMET Co-Processing - Rheinbraun Co-Processing - TUC Co-Processing - UOP Slurry-Catalysed Co-Processing - HTI Co-Processing	- Sasol - Rentech - Syntroleum - Mobil Methanol-to-Gasoline (MTG) Process - Mobil Methanol-to-Olefins (MTO) Process - Shell Middle Distillate Synthesis (SMOS)

This is a listing of many of the different technologies used for synthetic fuel production. Please note that although this list was compiled for coal to liquids technologies, many of the same processes can also be used with biomass or natural gas feedstocks.

Indirect conversion

Indirect conversion has the widest deployment worldwide, with global production totaling around 260,000 barrels per day (41,000 m^3/d), and many additional projects under active development.

Indirect conversion broadly refers to a process in which biomass, coal, or natural gas is converted to a mix of hydrogen and carbon monoxide known as syngas either through gasification or steam methane reforming, and that syngas is processed into a liquid transportation fuel using one of a number of different conversion techniques depending on the desired end product.



The primary technologies that produce synthetic fuel from syngas are Fischer-Tropsch synthesis and the Mobil process (also known as Methanol To Gasoline, or MTG). There are some technologies under development to produce ethanol from syngas, though these have not yet been demonstrated at commercial scale.

The Fischer-Tropsch process reacts syngas with typically a cobalt or iron-based catalyst, and transforms the gas into liquid products (primarily diesel fuel and jet fuel) and potentially waxes (depending on the FT process employed).

The process of producing synfuels through indirect conversion is often referred to as coal-to-liquids (CTL), gas-to-liquids (GTL) or biomass-to-liquids (BTL), depending on the initial feedstock. At least three projects (Ohio River Clean Fuels, Illinois Clean Fuels, and Rentech Natchez) are combining coal and biomass feedstocks, creating hybrid-feedstock synthetic fuels known as Coal and Biomass To Liquids (CBTL).[23]

Indirect conversion process technologies can also be used to produce hydrogen, potentially for use in fuel cell vehicles, either as slipstream co-product, or as a primary output.[24]

Direct conversion

Direct conversion refers to processes in which coal or biomass feedstocks are converted directly into intermediate or final products, without going through the intermediate step of conversion to syngas via gasification.

Direct conversion processes can be broadly broken up into two different methods: Pyrolysis and carbonization, and hydrogenation.[*citation needed*]

Hydrogenation processes

See also: Bergius process

One of the main methods of direct conversion of coal to liquids by hydrogenation process is the Bergius process.[25] In this process, coal is liquefied by mixing it with hydrogen gas and heating the system (hydrogenation). Dry coal is mixed with heavy oil recycled from the process. Catalyst is typically added to the mixture. The reaction occurs at between 400 °C (752 °F) to 5,000 °C (9,030 °F) and 20 to 70 MPa hydrogen pressure. The reaction can be summarized as follows:

$$n\mathrm{C} + (n+1)\mathrm{H}_2 \rightarrow \mathrm{C}_n\mathrm{H}_{2n+2}$$

After World War I several plants were built in Germany; these plants were extensively used during World War II to supply Germany with fuel and lubricants.[26]

The Kohleoel Process, developed in Germany by Ruhrkohle and VEBA, was used in the demonstration plant with the capacity of 200 ton of lignite per day, built in Bottrop, Germany. This plant operated from 1981 to 1987. In this process, coal is mixed with a recycle solvent and iron catalyst. After preheating and pressurizing, H_2 is added. The process takes place in tubular reactor at the pressure of 300 bar and at the temperature of 470 °C (880 °F).[27] This process was also explored by SASOL in South Africa.

In 1970-1980s, Japanese companies Nippon Kokan, Sumitomo Metal Industries and Mitsubishi Heavy Industries developed the NEDOL process. In this process, coal is mixed with a recycled solvent and a synthetic iron-based catalyst; after preheating H_2 is added. The reaction takes place in tubular reactor at temperature between 430 °C (810 °F) and 465 °C (870 °F) at the pressure 150-200 bar. The produced oil has low quality and requires intensive upgrading.[27] H-Coal process, developed by Hydrocarbon Research, Inc., in 1963, mixes pulverized coal with recycled liquids, hydrogen and catalyst in the ebullated bed reactor. Advantages of this process are that dissolution and oil upgrading are taking place in the single reactor, products have high H/C ration, and a fast ration time, while the main disadvantages are high gas yield, high hydrogen consumption, and limitation of oil usage only as a boiler oil because of impurities.[28]

The SRC-I and SRC-II (Solvent Refined Coal) processes developed by Gulf Oil and implemented as pilot plants in the United States in the 1960s and 1970s.[27] The Nuclear Utility Services Corporation developed hydrogenation process which was patented by Wilburn C. Schroeder in 1976. The process involved dried, pulverized coal mixed with roughly 1wt% molybdenum catalysts.[7] Hydrogenation occurred by use of high temperature and pressure syngas produced in a separate gasifier. The process ultimately yielded a synthetic crude product, Naphtha, a limited amount of C_3/C_4 gas, light-medium weight liquids (C_5-C_{10}) suitable for use as fuels, small amounts of NH_3 and significant amounts of CO_2.[29] Other single-stage hydrogenation processes are the Exxon Donor Solvent Process, the Imhausen High-pressure Process, and the Conoco Zinc Chloride Process.[27]

There is also a number of two-stage direct liquefaction processes; however, after 1980s only the Catalytic Two-stage Liquefaction Process, modified from the H-Coal Process; the Liquid Solvent Extraction Process by British Coal; and the Brown Coal Liquefaction Process of Japan have been developed.[27]

Pyrolysis and carbonization processes

See also: Karrick process

There are a number of different carbonization processes. The carbonization conversion occurs through pyrolysis or destructive distillation, and it produces condensable coal tar, oil and water vapor, non-condesable synthetic gas, and a solid residue-char. The condensed coal tar and oil are then further processed by hydrogenation to remove sulfur and nitrogen species, after which they are processed into fuels.[28]

The typical example of carbonization is the Karrick process. The process was invented by Lewis Cass Karrick in the 1920s. The Karrick process is a low-temperature carbonization process, where coal is heated at 680 °F (360 °C) to 1,380 °F (750 °C) in the absence of air. These temperatures optimize the production of coal tars richer in lighter hydrocarbons than normal coal tar. However, the produced liquids are mostly a by-product and the main product is semi-coke, a solid and smokeless fuel.[30]

The COED Process, developed by FMC Corporation, uses a fluidized bed for processing, in combination with increasing temperature, through four stages of pyrolysis. Heat is transferred by hot gases produced by combustion of part of the produced char. A modification of this process, the COGAS Process, involves the addition of gasification of char.[28] The TOSCOAL Process, an analogue to the TOSCO II oil shale retorting process and Lurgi-Ruhrgas process, which is also used for the shale oil extraction, uses hot recycled solids for the heat transfer.[28]

Liquid yields of pyrolysis and Karrick processes are generally low for practical use for synthetic liquid fuel production.[30] Furthermore, the resulting liquids are of low quality and require further treatment before they can be used as motor fuels. In summary, there is little possibility that this process will yield economically viable volumes of liquid fuel.[30]

Biofuels processes

One example of a Biofuel based synthetic fuel process is Hydrotreated Renewable Jet (HRJ) fuel. There are a number of variants of these processes under development, and the testing and certification process for HRJ aviation fuels is beginning.[31][32]

There are two such process under development by UOP. One using solid biomass feedstocks, and one using bio-oil and fats. The process using solid second-generation biomass sources such as switchgrass or woody biomass uses pyrolysis to produce a bio-oil, which is then catalytically stabilized and deoxygenated to produce a jet-range fuel. The process using natural oils and fats goes through a deoxygenation process, followed by hydrocracking and isomerization to produce a renewable Synthetic Paraffinic Kerosene jet fuel.[33]

Oil sand and oil shale processes

See also: Synthetic crude and Shale oil extraction

Synthetic crude may also be created by upgrading bitumen (a tar like substance found in oil sands), or synthesizing liquid hydrocarbons from oil shale. There are number of processes extracting shale oil (synthetic crude oil) from oil shale by pyrolysis, hydrogenation, or thermal dissolution.[10][34]

Commercialization

The leading company in the commercialization of synthetic fuel is Sasol, a company based in South Africa.

Worldwide commercial synthetic fuels plant capacity is over 240,000 barrels per day (38,000 m^3/d), including indirect conversion Fischer Tropsch plants in South Africa (Mossgas, Secunda CTL), Qatar {Oryx GTL}, and Malaysia (Shell Bintulu), and a Mobil process (Methanol to Gasoline) plant in New Zealand.[2][35]

Numerous large projects are under construction in China and Qatar. Some analysts believe that Chinese CTL production will exceed that of South Africa by 2015,[36] and new and existing GTL capacity in Qatar should also exceed the July 2009 South African production level some time in 2011.[37]

Existing producers

The leading company in the commercialization of synthetic fuel is Sasol, a company based in South Africa. Sasol operates the world's only commercial Fischer Tropsch coal-to-liquids facility at Secunda, with a capacity of 150,000 barrels per day (24,000 m^3/d).[38]

Sasol's Oryx Fischer Tropsch gas-to-liquids plant in Ras Laffan Industrial City, Qatar is running at 29,000 barrels per day (4,600 m^3/d) capacity, near its anticipated 34,000 barrels per day (5,400 m^3/d) nameplate capacity.[39]

Royal Dutch Shell operates a 14,700 barrels per day (2,340 m^3/d) Fischer Tropsch gas-to-liquids plant in Bintulu, Malaysia.[40]

The Mossgas gas to liquids plant in South Africa produces 45,000 barrels per day (7,200 m^3/d) of Fischer Tropsch synthetic fuels.[41]

Other companies that have developed coal- or gas-to-liquids processes (at the pilot plant or commercial stage) include ExxonMobil, StatoilHydro, Rentech, and Syntroleum .[42][43]

Projects under construction

The Pearl GTL project, a joint venture of Shell and Qatar Petroleum, is under construction in Ras Laffan, Qatar, and will produce 140,000 barrels per day (22,000 m^3/d) of Fischer Tropsch petroleum liquids starting in 2010 (first train) and 2011 (second train).[44]

The Escravos GTL project in Nigeria is expected to produce 34,000 barrels per day (5,400 m^3/d) of Fischer Tropsch synthetic fuel in 2011.[45]

Shenhua completed a trial run in January 2009, and expects to begin operation in July 2009 of their 1.08 million ton per year (roughly 22,200 barrels per day (3,530 m^3/d)) direct coal liquefaction plant (Erdos CTL) in Ejin Horo Banner in north China's Inner Mongolia autonomous region. Shenhua eventually intends to expand the facility to 5 million tons per year (roughly 102,000 barrels per day (16,200 m^3/d)).[46] The Shenhua Group also expects to complete a 6 Million ton per year (3 Million TPY first phase) coal-to-fuel project using its own Fischer Tropsch indirect conversion technology next to the Inner Mongolia plant in the third quarter of 2009.[47][48]

Yankuang expects to break ground shortly on a 22,000 barrels per day (3,500 m^3/d) (1 million ton per year) indirect synthetic fuels project. Final products will include 780,800 tons of diesel, 258,400 of naphtha, 56,480 of LPG.[49]

Proposed projects

United States

In the United States, a number of different synthetic fuels projects are moving forward, with the first expected to enter commercial operation starting in 2013.[50]

American Clean Coal Fuels, in their Illinois Clean Fuels project, is developing a 30,000 barrels per day (4,800 m^3/d) Fischer Tropsch biomass and coal to liquids project with carbon capture and sequestration in Oakland Illinois. The project is expected to come online in 2013.[51]

Baard Energy, in their Ohio River Clean Fuels project, are developing a 53,000 barrels per day (8,400 m^3/d) Fischer Tropsch coal and biomass to liquids project with the carbon capture and sequestration. Pending close of a financing package, Baard hopes to begin on site preparation work before the end of 2009, with plant construction starting in 2010. Initial project startup is anticipated in 2013, with full production capacity targeted in 2015.[52][53][54]

Rentech is developing a 29,600 barrels per day (4,710 m^3/d) Fischer Tropsch coal and biomass to liquids plant with carbon capture and sequestration in Natchez Mississippi. The project is in the permitting phase, with receipt of permits anticipated by Rentech in 2010.[55]

DKRW is developing a 15,000 to 20,000 barrels per day (2,400 to 3,200 m^3/d) Fischer Tropsch coal to liquids plant with carbon capture and sequestration in Medicine Bow Wyoming. The project is expected to begin operation in 2013.[56]

Aviation fuel

A significant effort is under way to certify FT synthetic fuels for use in US and international aviation fleets. In this effort is being led by an industry coalition known as the Commercial Aviation Alternative Fuels Initiative(CAAFI),[57] also supported by a parallel initiative under way in the US Air

Force ,[58] to certify FT fuel for use in all aviation platforms. The US Air Force has a stated goal of certifying its entire fleet for use with FT Synthetic Fuel blends by 2011.[59] The CAAFI initiative aims to certify the civilian aviation fleet for FT synthetic fuels blends by 2010, and has programs under way to certify HRJ hydrogenated biofuels as early as 2013.[60]

Presently, certification efforts appear to be ahead of schedule. On June 24, 2009 the ASTM International Aviation Fuels subcommittee voted to approve the creation of a new fuels specification allowing 50/50 blends of FT jet fuel to be used in commercial aviation. Assuming that this action is approved by the Petroleum Products and Lubricants committee of ASTM International, then CAAFI anticipates that the specification will be issued with its official ASTM designation by the fall. Ongoing research is continuing into HRJ fuels for incorporation in the standard, with HRJ fuels inclusion in the standard anticipated by the end of 2010, pending favorable evaluation of the research report.[61]

Sasol has also announced that they have achieved the first approval for 100% synthetic jet fuel use [62] sanctioned by global aviation fuel specification authorities.

On 12 October 2009, a Qatar Airways Airbus A340-600 conducted a the world's first commercial passenger flight using a mixture of kerosene and synthetic Gas-to-Liquid fuel in its flight from London's Gatwick Airport to Doha.[63]

JBUFF (Joint Battlespace Use Fuel of the Future) fuel

Future blends and fuel formulations may result in a JBUFF (Joint Battlespace Use Fuel of the Future) or a single battlespace fuel that can be used in both diesel and jet fuel application. A JBUFF fuel will allow for rapid deployment and logistic enhancement for military and emergency aid environments where various types of equipment can be operated with one fuel in place of several types of fuel.[64][65]

Initial consumers

In addition to their certification efforts, the United States Air Force has publicly stated their intention to fuel half of their domestic US flights with synthetic fuel by 2016.[66] The commercial aviation industry, working with potential suppliers via CAAFI, is also pushing hard to secure sources of fuel.[67]

The United States Department of Energy projects that domestic consumption of synthetic fuel made from coal and natural gas will rise to 3.7 million barrels per day (590×10^3 m^3/d) in 2030 based on a price of $57 per barrel of high sulfur crude.[2]

Non-transportation "synfuel"

Numerous American companies (TECO, Progress Energy, DTE Energy, Marriott) have also taken advantage of coal-based synfuel tax credits established in the 1970s, although many of the products qualifying for the subsidy are not true synthetic fuels.[68]

The coal industry uses the credit to increase profits on coal-burning powerplants by introducing a "pre-treatment" process that satisfies the technical requirements, then burns the result the same as it would burn coal. Sometimes the amount gained in the tax credit is a major factor in the economic operation of the plant. The synfuel tax credit has been used primarily in this manner since the cheap gas prices of the 1980s stopped any major efforts to create a transportation fuel with the credit, and its continuation is seen as a major "pork project" win for coal industry lobbyists, costing $9 billion per annum.[68][69] The total production of such synfuels in the United States was an estimated 73 million tons in 2002.[*citation needed*]

The synthetic fuel tax credit, Section 45K, under which these activities occurred, expired 31 December 2007.[70]

Economics

The economics of synthetic fuel manufacture vary greatly depending the feedstock used, the precise process employed, site characteristics such as feedstock and transportation costs, and the cost of additional equipment required to control emissions. The examples described below indicate a wide range of production costs between $20/BBL for large-scale gas-to-liquids, to as much as $240/BBL for small-scale biomass-to-liquids + Carbon Capture and Sequestration.[23]

In order to be economically viable, projects must do much better than just being competitive head-to-head with oil. They must also generate a sufficient return on investment to justify the capital investment in the project.[23]

GTL economics

A synthetic fuel manufactured from natural gas (GTL), without CCS, in a large scale plant in the Middle East (where gas is relatively inexpensive), is expected to be competitive with oil down to approximately $20 per barrel.[71]

Recent advances by the oil company Shell have seen synthetic fuels start to become profitable. The company is building a GTL (gas-to-liquid) plant in Qatar, due to come online in 2011. It will be capable of producing 300,000 barrels per day (48,000 m^3/d) of synthetic fuels and other products, using natural gas as a feedstock. Their spokesman claims the process will remain competitive with traditional diesel unless the price of crude falls below $20 per barrel.[72]

CTL/CBTL/BTL economics

According to a December 2007 study, a medium scale (30,000 BPD) coal-to-liquids plant (CTL) sited in the US using bituminous coal, is expected to be competitive with oil down to roughly $52–56/bbl crude-oil equivalent. Adding carbon capture and sequestration to the project was expected to add an additional $10/BBL to the required selling price, though this may be offset by revenues from enhanced oil recovery, or by tax credits, or the eventual sale of carbon credits.[73]

A recent NETL study examined the relative economics of a number of different process configurations for the production of indirect FT fuels using biomass, coal, and CCS.[23] This study determined a price at which the plant would not only be profitable, abut also make a sufficient return to yield a 20% return on the equity investment required to build the plant.

> This chapter details an analysis which derives the Required Selling Price (RSP) of the FT diesel fuels produced in order to determine the economic feasibility and relative competitiveness of the different plant options. A sensitivity analysis was performed to determine how carbon control regulations such as an emissions trading scheme for transportation fuels would affect the price of both petroleum-derived diesel and FT diesel from the different plants. The key findings of these analyses were: (1) CTL plants equipped with CCS are competitive at crude oil prices as low as $86 per barrel and have less life cycle GHG emissions than petroleum-derived diesel. These plants become more economically competitive as carbon prices increase. (2) The incremental cost of adding simple CCS is very low (7 cents per gallon) because CO_2 capture is an inherent part of the FT process. This becomes the economically preferred option at carbon prices above $5/mt$CO_2$eq.27 (3) BTL systems are hindered by limited biomass availability which affects the maximum plant size, thereby limiting potential economies of scale. This, combined with relatively high biomass costs results in FT diesel prices which are double that of other configurations: $6.45 to $6.96/gal compared to $2.56 to $2.82/gal for CTL and 15wt% CBTL systems equipped with CCS. The conclusion reached based on these findings was that both the CTL with CCS and the 8wt% to 15wt% CBTL with CCS configurations may offer the most pragmatic solutions to the nation’s energy strategy dilemma: GHG emission reductions which are significant (5% to 33% below the petroleum baseline) at diesel RSPs that are only half as much as the BTL options ($2.56 to $2.82 per gallon compared to $6.45 to $6.96 per gallon for BTL). These options are economically feasible when crude oil prices are $86 to $95 per barrel.

[23]

These economics can change in the event that plentiful low-cost biomass sources can be found, lowing the cost of biomass inputs, and improving economies of scale.

Economics for solid feedstock indirect FT process plants are further confused by carbon regulation. Generally, since permitting a CTL plant without CCS will likely be impossible, and CTL+CCS plants have a lower carbon footprint than conventional fuels, carbon regulation is expected to be balance-positive for synthetic fuel production. But it impacts the economics of different process configurations in different ways. The NETL study picked a blended CBTL process using 5-15% biomass alongside coal as the most economical in a range of carbon price and probable future regulation scenarios. Unfortunately, because of scale and cost constraints, pure BTL processes did not score well until very high carbon prices were assumed, though again this may improve with better feedstocks and more efficient larger scale projects.[23]

Chinese direct coal liquefaction economics

News reports have indicated an anticipated cost of production of less than $30 per barrel, based on a direct coal liquefaction process, and a coal mining cost of under $10/ton.[74]

Security considerations

A central consideration for the development of synthetic fuel is the security factor of securing domestic fuel supply from domestic biomass and coal. Nations that are rich in biomass and coal can use synthetic fuel to off-set their use of petroleum derived fuels and foreign oil.[75]

Environmental considerations

The environmental footprint of a given synthetic fuel varies greatly depending on which process is employed, what feedstock is used, what pollution controls are employed, and what the transportation distance and method are for both feedstock procurement and end-product distribution.[23]

In many locations, project development will not be possible due to permitting restrictions if a process design is chosen that does not meet local requirements for clean air, water, and increasingly, lifecycle carbon emissions.[76][77]

Lifecycle green house gas emissions

Among different indirect FT synthetic fuels production technologies, potential emissions of greenhouse gasses vary greatly. Coal to liquids ("CTL") without carbon capture and sequestration ("CCS") is expected to result in a significantly higher carbon footprint than conventional petroleum-derived fuels (+147%).[23] On the other hand, biomass-to-liquids with CCS could deliver a 358% reduction in lifecycle greenhouse gas emissions.[23] Both of these plants fundamentally use gasification and FT conversion synthetic fuels technology, but they deliver wildly divergent environmental footprints.[*citation needed*]

File:Coal and biomass co conversion to transportation fuels, Michael E Reed, DOE NETL Office of Fossil Energy, oct 17 2007.jpg

Lifecycle carbon emissions profiles of various fuels, including many synthetic fuels. Coal and biomass co-conversion to transportation fuels, Michael E. Reed, DOE NETL Office of Fossil Energy, Oct 17 2007

Generally, CTL without CCS has a higher greenhouse gas footprint. CTL with CCS has a 9-15% reduction in lifecycle greenhouse gas emissions compared to that of petroleum derived diesel.[23][78]

CBTL+CCS plants that blend biomass alongside coal while sequestering carbon do progressively better the more biomass is added. Depending on the type of biomass, the assumptions about root storage, and the transportation logistics, at conservatively 40% biomass alongside coal, CBTL+CCS plants achieve a neutral lifecycle greenhouse gas footprint. At more than 40% biomass, they begin to go lifecycle negative, and effectively store carbon in the ground for every gallon of fuels that they produce.[23]

Ultimately BTL plants employing CCS could store massive amounts of carbon while producing transportation fuels from sustainably produced biomass feedstocks, although there are a number of significant economic hurdles, and a few technical hurdles that would have to be overcome to enable the development of such facilities.[23]

Serious consideration must also be given to the type and method of feedstock procurement for either the coal or biomass used in such facilities, as reckless development could exacerbate environmental problems caused by mountaintop removal mining, land use change, fertilizer runoff, food vs. fuels concerns, or many other potential factors. Or they could not. Depending entirely on project-specific factors on a plant-by-plant basis.[*citation needed*]

A study from U.S. Department of Energy National Energy Technology Laboratory with much more in-depth information of CBTL life-cycle emissions "Affordable Low Carbon Diesel from Domestic Coal and Biomass": http://www.netl.doe.gov/energy-analyses/pubs/CBTL%20Final%20Report.pdf

Hybrid hydrogen-carbon processes have also been proposed recently[79] as another closed-carbon cycle alternative, combining 'clean' electricity, recycled CO, H_2 and captured CO_2 with biomass as inputs as a way of reducing the biomass needed.[*citation needed*]

Fuels emissions

The fuels produced by the various synthetic fuels process also have a wide range of potential environmental performance, though they tend to be very uniform based on the type of synthetic fuels process used (i.e. the tailpipe emissions characteristics of Fischer Tropsch diesel tend to be the same, though their lifecycle greenhouse gas footprint can vary substantially based on which plant produced the fuel, depending on feedstock and plant level sequestration considerations.)[*citation needed*]

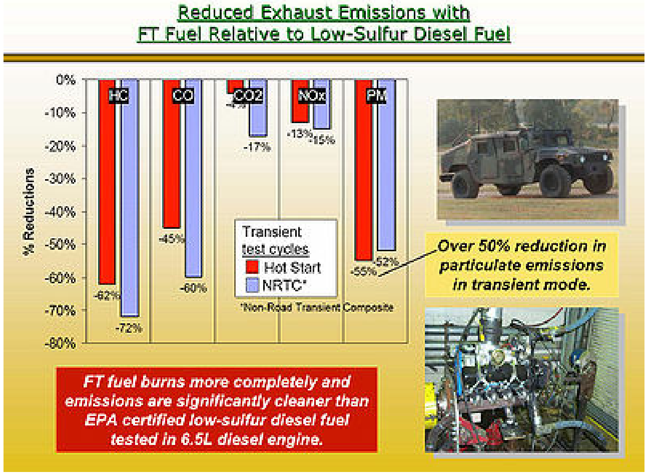
In particular, Fischer tropsch diesel and jet fuels deliver dramatic across-the-board reductions in all major criteria pollutants such as SOx, NOx, Particulate Matter, and Hydrocarbon emissions.[80] These fuels, because of their high level of purity and lack of contaminants, further enable the use of advanced emissions control equipment that has been shown to virtually eliminate HC, CO, and PM emissions from diesel vehicles.[81]

In testimony before the Subcommittee on Energy and Environment of the U.S. House of Representatives the following statement was made by a senior scientist from Rentech:

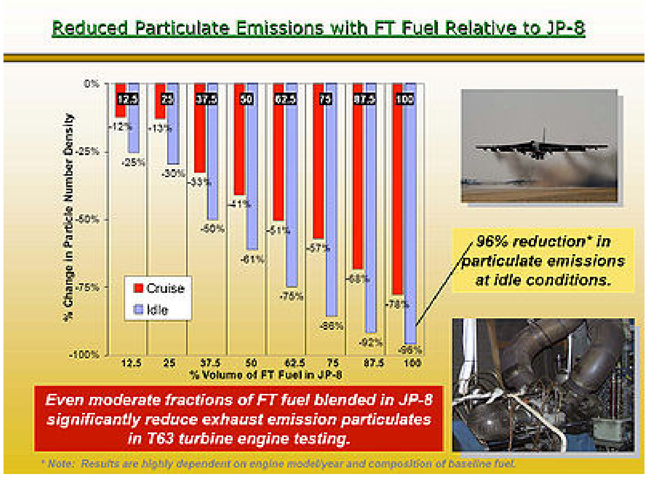
> F-T fuels offer numerous benefits to aviation users. The first is an immediate reduction in particulate emissions. F-T jet fuel has been shown in laboratory combusters and engines to reduce PM emissions by 96% at idle and 78% under cruise operation. Validation of the reduction in other turbine engine emissions is still under way. Concurrent to the PM reductions is an immediate reduction in CO_2 emissions from F-T fuel. F-T fuels inherently reduce CO_2 emissions because they have higher energy content per carbon content of the fuel, and the fuel is less dense than conventional jet fuel allowing aircraft to fly further on the same load of fuel.

[82]

The cleanliness of these FT synthetic fuels is further demonstrated by the fact that they are sufficiently non-toxic and environmentally benign as to be considered biodegradable. This owes primarily to the near-absence of sulfur and extremely low level of aromatics present in the fuel.[83]

- 

  Using Fischer Tropsch diesel results in dramatic across the board tailpipe emissions reductions relative to conventional fuels

- 

  Using Fischer Tropsch jet fuels have been proven to dramatically reduce particulate and other aircraft emissions

Sustainability

One concern commonly raised about the development of synthetic fuels plants is sustainability. Fundamentally, transitioning from oil to coal or natural gas for transportation fuels production is a transition from one inherently depeleteable geologically limited resource to another.[*citation needed*]

One of the positive defining characteristics of synthetic fuels production is the ability to use multiple feedstocks (coal, gas, or biomass) to produce the same product from the same plant. In the case of hybrid BCTL plants, some facilities are already planning to use a significant biomass component alongside coal. Ultimately, given the right location with good biomass availability, and sufficiently high oil prices, synthetic fuels plants can be transitioned from coal or gas, over to a 100% sustainable biomass feedstock. This provides a path forwards to true sustainable fuel production, even if the plant originally produced fuels solely from coal, making the infrastructure forwards-compatible even if the original fossil feedstock runs out.[*citation needed*]

Some synthetic fuels processes can be converted to sustainable production practices more easily than others, depending on the process equipment selected. This is an important design consideration as these facilities are planned and implemented, as additional room must be left in the plant layout to accommodate whatever future materials handling and gasification plant change requirements might be necessary to accommodate a future change in production profile.[*citation needed*]

See also

- Gasification
- Methanol to gasoline
- Biofuel
- Butanol fuel
- Gas to liquids
- Synthetic oil
- Synthetic Fuels Corporation
- Synthetic Liquid Fuels Program
- Cracking
- Shale oil extraction
- Pyrolysis
- Methanol economy

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