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Simulation Model  
(H<sub>2</sub>Sim)

# Pathways to a Hydrogen Future



Thomas E. Drennen and Jennifer E. Rosthal

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THOMAS E. DRENNEN

JENNIFER E. ROSTHAL



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Thomas E. Drennen  
Geneva NY

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Part I  
**Overview**

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# Chapter 1

## The Hydrogen Futures Simulation Model (H<sub>2</sub>Sim): Pathways to a Hydrogen Future

Yes, my friends, I believe that water will one day be employed as fuel, that hydrogen and oxygen which constitute it, used singly or together, will furnish an inexhaustible source of heat and light, of an intensity of which coal is not capable. . . . When the deposits of coal are exhausted we shall heat and warm ourselves with water. Water will be the coal of the future.

Jules Verne, *The Mysterious Island*, 1875

In this century, the greatest environmental progress will come about not through endless lawsuits or command-and-control regulations, but through technology and innovation. Tonight I'm proposing \$1.2 billion in research funding so that America can lead the world in developing clean, hydrogen-powered automobiles. . . . With a new national commitment, our scientists and engineers will overcome obstacles to taking these cars from laboratory to showroom, so that the first car driven by a child born today could be powered by hydrogen, and pollution-free.

George W. Bush, State of the Union Address, 2003

For almost 200 years, the possibility of someday using hydrogen as a substitute for coal and other fuel sources has intrigued the scientists and dreamers among us. In Jules Verne's book, *The Mysterious Island*, Captain Cyrus Harding, one of five castaways on the island, explains how mankind will use hydrogen from water as a source of heat once supplies of the precious mineral coal are exhausted. While Verne foresaw burning the hydrogen, Sir Robert Grove, a British physicist, in 1839 demonstrated a working fuel cell in which hydrogen and oxygen would react and create electricity in the process. About 130 years after the tale of Captain Harding was spun, hydrogen still is seen as the fuel of the future.

Someday, hydrogen may fuel our cars and power and heat our homes and businesses. Moving to a hydrogen economy could help reduce our reliance on foreign oil, improve local air quality, and reduce the risk of climate change. In short, hydrogen could revolutionize the way we use energy. Despite the potential of hydrogen, there is no guarantee that the hydrogen economy will happen, or that it will happen in the time frame envisioned by President Bush and others. The obstacles are considerable and the competing visions are many.

This book seeks to untangle the competing visions of a hydrogen economy, explain the trade-offs and obstacles along the path, and offer recommendations for a path forward. The results are based on a detailed simulation model developed at Sandia National Laboratories: “The Hydrogen Futures Simulation Model (H<sub>2</sub>Sim).”

H<sub>2</sub>Sim is a high-level strategic tool for evaluating the economic and environmental trade-offs of alternative hydrogen production, storage, transport, and end-use options in the year 2020, the timeframe envisioned in Bush’s 2003 State of the Union speech. An executive version of H<sub>2</sub>Sim is included with this book so that readers can explore various scenarios discussed in this book and perhaps come to their own conclusions about the future of hydrogen.<sup>1</sup>

The model’s structure is ideal for exploring “what-if” type questions, such as: Can fuel cell vehicles (FCVs) compete economically with current cars if the FCVs are 2.5 times as efficient? Should the hydrogen be produced at fueling stations or at central locations and transported to fueling stations? Could hydrogen produced from off-peak electricity at 1 cent per kilowatt hour (kWh) compete with gasoline? Would carbon emissions from the transportation sector increase or decrease if the source of hydrogen for FCVs was coal or natural gas or electricity? H<sub>2</sub>Sim’s ease of use and its ability to provide answers to these types of questions make it a powerful educational and policy making tool.

### **Interest in the Hydrogen Economy**

While visions of a hydrogen future have been around for almost two centuries, recent advancements in fuel cell and hydrogen production technologies make that vision increasingly likely. Virtually every major automobile company has research and development programs aimed at commercializing hydrogen technologies and competing prototype cars

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<sup>1</sup> Full versions of H<sub>2</sub>Sim can be licensed from Sandia National Laboratories. For more information, contact the author directly.

and buses. General Motors' stated goal is to begin selling fuel cell cars by 2010 and to sell 1 million cars by 2015 (Burns 2003). Larry Burns, vice president of research, development and planning at GM, envisions a future where hydrogen is produced at home or work using small-scale hydrogen appliances, devices smaller than a traditional refrigerator or washing machine. Small-scale natural gas reformers would break apart natural gas (methane - CH<sub>4</sub>) to produce hydrogen. Alternatively, small-scale electrolyzers could separate the hydrogen and oxygen from water. In either case, the consumer simply would "plug in" the car to the hydrogen appliance at home so that the car would be fueled and ready to go.

In 2005, Honda became the first company to put a FCV in the hands of a consumer. To gather real world data, Honda selected one family near their California headquarters to lease for \$500 per month their experimental FCV, the FCX. Honda also built a fueling station near the family's house. Hakim (2005) reports the vehicle is worth about \$1 million. The FCX has an electric motor, rated at 107 horsepower (hp). Initial reports from the family are positive. In addition to the positive reviews of the FCX, the first leasee notes an added benefit: "I don't like our dependence on foreign oil. I think it causes us to do a lot of stupid things as a country" (Hakim 2005).

Other companies are more guarded in their enthusiasm for hydrogen powered vehicles, noting significant technical, safety, economic, and infrastructure issues. While Toyota has multiple prototypes in Japan and the United States, the company's short-term plan is to focus on hybridized technologies, noting "hybrid technology is key to creating highly efficient vehicles" in the near term (Kawai 2003). Focusing on hybrids will provide Toyota with valuable experience with electric drive trains in vehicles. Once fuel cells become commercially viable, Toyota will be ready to simply replace the gasoline engine with the fuel cell. However, Toyota acknowledges the rationale for eventually moving to FCVs. They estimate the overall efficiency, or the well-to-wheel efficiency,<sup>2</sup> of the hybrid vehicle is around 29%, compared to about 16% for the typical internal combustion engine (ICE) vehicle (Kawai 2003). Toyota predicts that a hybridized FCV will be able to achieve an overall efficiency of 42%, 1.5 times better than gasoline hybrids and three times better than the ICE vehicle (Kawai 2003).

Governments, auto manufacturers, and even oil companies are exploring hydrogen options for several other good reasons, including: soaring

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<sup>2</sup> Well-to-wheel efficiency includes both the 'well-to-tank efficiency', associated with the entire front end of the fuel and vehicle production, and the 'tank-to-wheel efficiency', the efficiency of the vehicle.

worldwide growth in energy demand and recognition that fossil fuels are a limited resource, concerns about the overall security of our existing energy infrastructure, and an increased awareness of the impact of energy use patterns on local and global environments.

### Global Energy Demand and Resource Availability

World energy demand in 2003 was 417 quads,<sup>3</sup> a 20% increase from 1990 levels (EIA 2005). More than half of that was consumed by the 950 million people in industrialized countries. The United States, with just 5% of the world's population, accounts for 25% of total energy demand. The US Department of Energy (DOE) predicts that total demand will reach 645 quads by 2025, a further 54% increase (EIA 2005). What is not projected to change is the heavy reliance on fossil fuels. The share of global primary energy demand provided from fossil fuels is currently 86%; the DOE projects fossil fuel's share will remain fairly constant through 2025 (EIA 2003c).

A large part of the increased energy demand over time is due to the near absolute reliance on oil in the transportation sector. Total world oil demand is expected to increase from 77 million barrels per day (mbd) in 2003 to 119 mbd in 2025, a 55% increase (EIA 2005). This growth is fueled not just by continued demand in the industrialized world, but also by the rapid growth of oil demand in developing countries. Their share is projected to increase to 45% by 2025, up from 26% in 1990 (EIA 2005).

While current energy consumption depends primarily on fossil fuels, the world cannot rely on them forever. We eventually will be constrained by resources. Reserve estimates<sup>4</sup> and corresponding reserve-to-production (*R:P*) ratios, defined as the number of years reserves will last at current production levels, are summarized in Table 1.1.

For oil, the *R:P* ratios indicate that remaining oil reserves are sufficient to last 35–78 years at current production levels. Reserve-to-production ratios are highly misleading for several reasons. First, production levels will increase to meet the projected 45% increase in oil demand projected for 2025 (EIA 2005). Reserve sizes are not fixed. Reserves are resources

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<sup>3</sup> 1 Quad =  $1 \times 10^{15}$  BTU = 1.055 EJ. One quad of electricity will light 557 million 60-watt light bulbs for 1 year.

<sup>4</sup> Estimates of crude oil from the EIA are for proved reserves, defined by the EIA (2003a) as 'the estimated quantities of all liquids defined as crude oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions'.

Table 1.1. Reserve estimates and corresponding  $R:P$  ratios.

	Reserve estimates	$R:P$
Oil (billion barrels)	1000–2203	35–78
Natural gas (trillion cubic feet)	4793–5304	54–60
Coal (million short tons)	1 083 259	206

Source: EIA 2003a; BP 2001; Ahlbrandt et al. 2000.

that can be recovered economically with current technology. Thus, even without the discovery of new fields, reserves increase if world oil prices increase, as resources previously deemed uneconomical become economical. Technological advances in drilling and recovery methods also lead to increased reserves.

An alternative measure of remaining resources relies on Hubbert's Peak analysis. M. King Hubbert, an employee at the United States Geologic Survey, postulated that resource production essentially follows a classic bell-shaped curve and that production peaks once half the resource has been depleted. In 1956, Hubbert predicted that US oil production would peak in the early 1970s. Most people in the industry initially rejected his analysis. However, Hubbert was right – US oil production peaked exactly as predicted, reaching 9.6 mbd in 1971. Despite increased production from Alaska, US production had fallen to 5.4 mbd by 2004 (EIA 2006).

Applying Hubbert's methodology to world production, several predict a global peak is imminent, if it has not already happened. Campbell and Laherrère (1998) estimated that global production will peak sometime in the 2003–2009 period. Once production peaks, prices will begin to increase, accelerating the transition to alternative sources. Global production will continue decreasing until reserves are depleted in approximately 40 years or become too expensive to extract, a similar result to the more simplistic  $R:P$  estimate. Despite this apparent agreement between the two methodologies, there is still considerable debate about the sufficiency of remaining reserves. Questions center on the future likelihood of technological advances and discovery of new deposits, and the potential for unconventional sources of oil, such as oil sands and shale. Estimates suggest as many as 1.7 trillion barrels of oil are trapped in oil sands beneath the ground in Alberta (Woynillowicz et al. 2005).

Almost as important as reserve size is its distribution. Only 5% of proven crude oil reserves are located within the borders of member nations of the Organization for Economic Cooperation and Development

(OECD).<sup>5</sup> Two-thirds of the world's remaining oil reserves are located within member nations of the Organization of Petroleum Exporting Countries (OPEC)<sup>6</sup> (EIA 2003b). Natural gas reserves follow a similar distribution pattern. Only 10% of the world reserves are located in OECD nations. The rest is located mainly in OPEC countries (just under one-half) and Russia (one-third) (EIA 2003b). Coal reserves, however, are more plentiful, and distributed in other parts of the world. Approximately three-quarters of the world's coal reserves are found in North America, Asia, Oceania, Eastern Europe, and the former Soviet Union (EIA 2003b).

### **Energy Security**

This uneven distribution of world resources and the resulting dependence of many countries on politically unstable nations raise concerns about energy security. The United States imported 53% of its oil in 2002. The EIA (2004) projects US oil imports could reach 70% by 2025. Forty-four percent of global exports originate in Middle East countries; another 10% originates in the former Soviet Union (BP 2003). Net imports of oil into OECD countries in 2002 comprised approximately half of global consumption, and total imports will grow as domestic resources are depleted (EIA 2003a). This trade balance gives great power to OPEC member countries, a power that is expected to increase as the developing world demands more oil.

The political situation within OPEC member countries is complicated and dynamic. Price shocks caused by political unrest in oil-exporting countries have had severe economic effects on the global economy, including losses in gross domestic product (GDP) and increases in inflation and unemployment. Oil market stability concerns are rooted both in political volatility and infrastructure insecurity. Further uncertainty arises from the entry of new suppliers, especially Russia, into the market and their cooperation, or lack thereof, with OPEC. In terms of supply security, the hub-and-spoke oil transportation system in both importing and exporting countries remains vulnerable to attacks. Some suggest a

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<sup>5</sup>The Organization for Economic Cooperation and Development (OECD) countries include Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States.

<sup>6</sup>The Organization of Petroleum Exporting Countries (OPEC) includes Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

successful attack on even a few key points in this system could cause catastrophic supply problems (Baer 2003).

### **Environmental Considerations**

Local and global environmental concerns are another driver in the push toward a hydrogen economy. At the global level, scientists warn that the combustion of fossil fuels is causing significant changes to the global climate system by increasing the concentration of greenhouse gases and magnifying the greenhouse effect. Local or regional concerns include smog, acid rain, and the health implications of urban air pollution.

There is no doubt that the greenhouse effect is real. The greenhouse effect is a natural occurrence responsible for the current climatic conditions on Earth. Without this natural effect, the Earth's temperature would be about 33°C colder (IPCC 2001). The ultimate question is how the Earth's climate system will respond to the increasing concentrations of greenhouse gases caused by human activities. Atmospheric concentrations of the main greenhouse gas – carbon dioxide – released during the combustion of fossil fuels have increased exponentially from 280 parts per million (ppm) to just over 370 ppm since the Industrial Revolution (IPCC 2001).

The Intergovernmental Panel on Climate Change (IPCC) (2001), established by the international community in 1988 to provide unbiased scientific analysis regarding the potential for and effects of human-induced climate change, reports that global temperatures have increased 0.6°C (1.08°F) since 1860. On the basis of the assumption that world use of fossil fuels will continue, the IPCC predicts that average global surface temperatures will increase by an additional 1.4–5.8°C by 2100, a rate of warming unprecedented in the last 10 000 years. Likely physical effects of this temperature increase will include increased sea levels, changes in regional weather patterns (increased precipitation in some regions and less precipitation in others), and increased incidence of violent weather systems, such as hurricanes.

While carbon dioxide and the greenhouse effect pose a serious long-term threat to the environment, other emissions from our energy consumption threaten the environment and our health in the near term. These emissions include carbon monoxide (CO), nitrous oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), particulate matter (PM), volatile organic compounds (VOC), and ozone (O<sub>3</sub>). The emissions of these gases results in a combination of health and environmental problems. In the United States, awareness of the problems associated with various local or regional pollutants has led to significant reductions. Cackette (2003) notes that a vintage 1975 car released over two tons of hydrocarbons and NO<sub>x</sub> over

its lifetime; cars meeting California's new partial zero emission vehicle (PZEV) standards emit just 20 pounds over their lifetimes. However, rapidly expanding use of automobiles in other countries, particularly developing countries, remains a threat to local and regional air quality. During the early 1990s, for example, the level of total suspended particulates in Delhi, India, was approximately five times the World Health Organization's (WHO) recommended guidelines (Cropper et al. 1997).

### Pathways to a Hydrogen Future

Hydrogen offers a possible solution to such problems as energy security, resource availability, and environmental concerns. The supply is unlimited. No one country or group of countries controls access to it. And it has the potential to be a carbon-free source, unless produced from hydrocarbons. While hydrogen is the most abundant element in nature, it must be stripped from either hydrocarbons (coal, oil, or natural gas) or water. The separated hydrogen can be used in fuel cells to generate electricity or can be combusted in modified engines.

While there are many different fuel cell designs, the basic principle is similar (Figure 1.1). The proton exchange membrane (PEM) fuel cell currently is preferred for use in vehicles because of its low operating

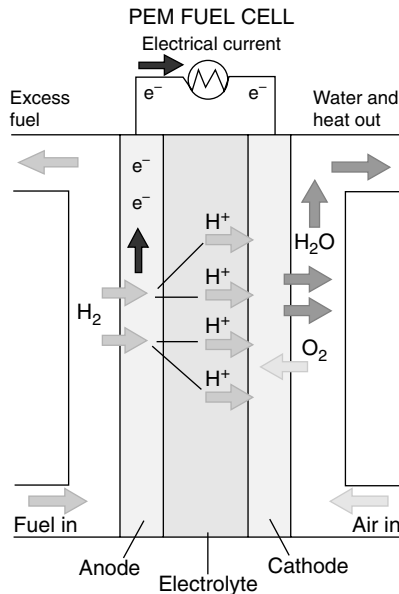


Figure 1.1. Proton exchange membrane fuel cell schematic.  
(Source: EERE 2006).

temperature. The fuel cell contains both a negatively and a positively charged electrode. Hydrogen ( $H_2$ ) enters the fuel cell on the positive side where the electrons are stripped off. The remaining positively charged hydrogen ions pass through a membrane to the negative side. The electrons cannot pass through the membrane but instead flow through a wire connecting the two sides, providing a direct current which then can run an electric motor. The hydrogen ion then combines with the oxygen atoms and the electrons to form water and heat. Some of this water is re-used to humidify the membrane. The rest exits out the tailpipe.

By stacking several fuel cells together, enough electricity can be generated to power a car or a bus. Fuel cells also can be used as stationary power and heat sources in residential and commercial settings. There are several hurdles to the commercial deployment of fuel cells in vehicles and for stationary sources: cost (vehicle, fuel, and operating), fuel cell durability, safety issues, customer acceptance, and infrastructure development.

Perhaps the largest hurdle is making sure that once the other technical challenges are met, there will be readily accessible hydrogen for consumer use. Fueling stations will be unwilling to install expensive hydrogen delivery systems until there is a large enough demand. And consumers will be unwilling to purchase hydrogen vehicles unless they are assured the hydrogen is available. It is a classic chicken-and-egg problem.

### **Centralized versus Decentralized Hydrogen Production Options**

A fundamental question is how and where to produce the hydrogen. The hydrogen economy could develop in a variety of ways. Perhaps the easiest pathway to envision in the short term is one where users continue to fuel their cars with gasoline, a hydrocarbon. An onboard reformer then separates the hydrogen from the gasoline for use in the fuel cell. Another possibility is to produce the hydrogen at small, decentralized locations, such as the household level or fueling stations. Finally, the hydrogen could be produced at large, centralized facilities and then transported to fueling stations by truck or pipeline, much like natural gas and gasoline are distributed today (Figure 1.2).

Producing the hydrogen onboard as needed solves the infrastructure problem, but there are some clear drawbacks to the approach. The reformer would add to the cost of the vehicle and take up additional room. The added weight would hurt fuel economy. A reformer placed at a centralized location might operate 80–95% of the time, but an onboard version would operate a fraction of that time and be an underutilized capital asset. Most importantly, if the original fuel is gasoline, then

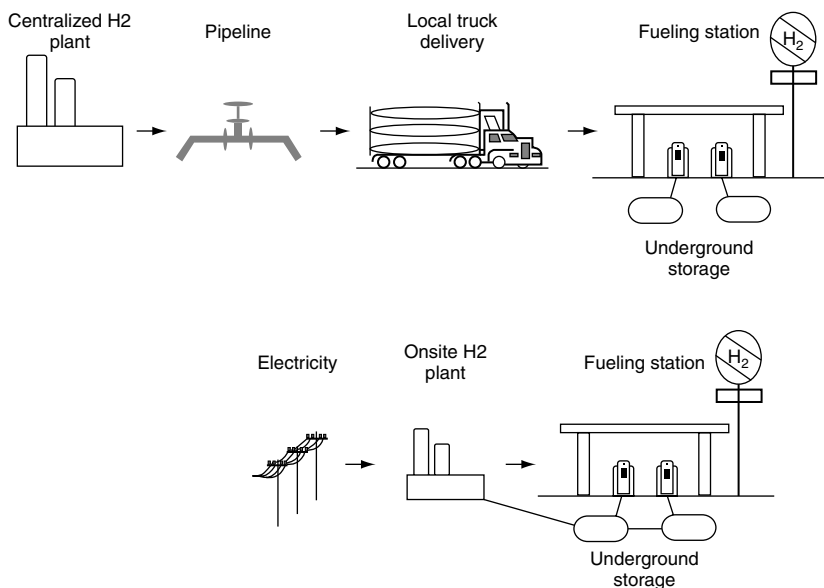


Figure 1.2. Centralized versus decentralized hydrogen production.

this option would not solve the problems associated with the current hydrocarbon energy system. For this reason, some suggest it only as a transitional solution to a more fully developed hydrogen economy.

At the other end of the spectrum is a centralized approach to hydrogen production. Hydrogen would be produced at large centralized facilities and then transported to fueling stations. Several options for centralized production exist, including steam reformation of natural gas, coal gasification, electrolysis, non-catalytic partial oxidation (NPO) of petroleum, and thermochemical separation of water using high temperatures from either nuclear or solar sources. Once produced, the hydrogen would be delivered by truck, rail, ship, or pipeline to the fueling station and transported in either gaseous or liquid form or stored in the lattices of certain metals. Depending on the actual method of transportation, the hydrogen might have to be stored at the production plant and/or the fueling station. The end user would then directly refuel the vehicle with hydrogen.

Perhaps the most compelling case for centralized production is that it would allow for greater diversification in terms of energy feedstocks, decreasing the vulnerability of the transportation sector through resource diversification. Of course, if there is a clear economic winner, such as coal gasification, then diversification may not happen.

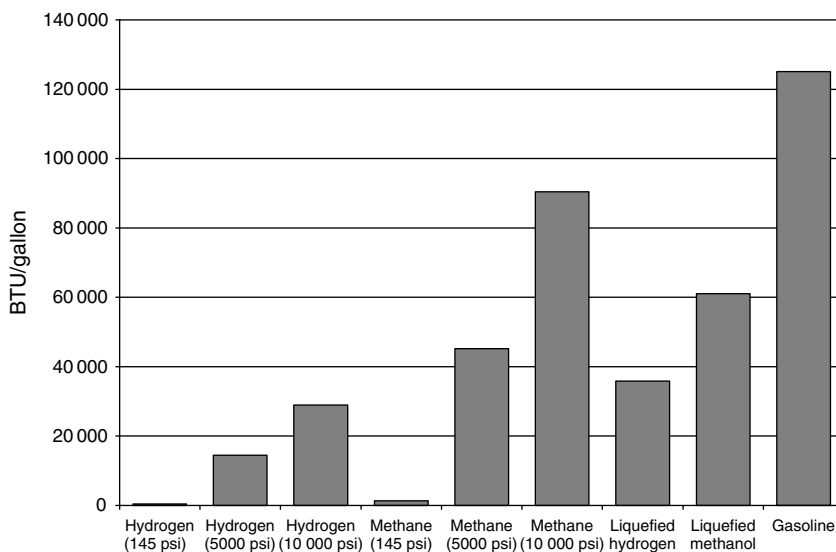


Figure 1.3. Densities of various fuel options.  
(Source: Bossel et al. (2003)).

The single largest drawback to the centralized approach is that the hydrogen must then be transported to the end user. Unfortunately, the low volumetric density of hydrogen relative to other fuel options makes it difficult to transport (Figure 1.3). The same quantity of energy in the form of hydrogen compressed to 5000 pounds per square inch (psi) takes almost 10 times more space than a comparable quantity of gasoline.

A more decentralized approach to hydrogen production could eliminate, or at least greatly reduce, delivery and storage costs. Decentralized options include use of small-scale reformers or electrolyzers at either the fueling station or possibly even at the individual household level. The diseconomies of scale associated with operating smaller hydrogen production units could be offset by the savings in delivery and storage costs. In *The Hydrogen Economy*, Rifkin (2002) argues that a decentralized approach would lead to a democratization of energy, giving each individual, community, and nation self-sufficiency and independence. This independence, he contends, could lead to a “reglobalization” of society, creating a dramatic shift in power.

### Hydrogen Futures Simulation Model

With the existence of many competing visions for a hydrogen economy, H<sub>2</sub>Sim was designed to assist policy-makers and other interested

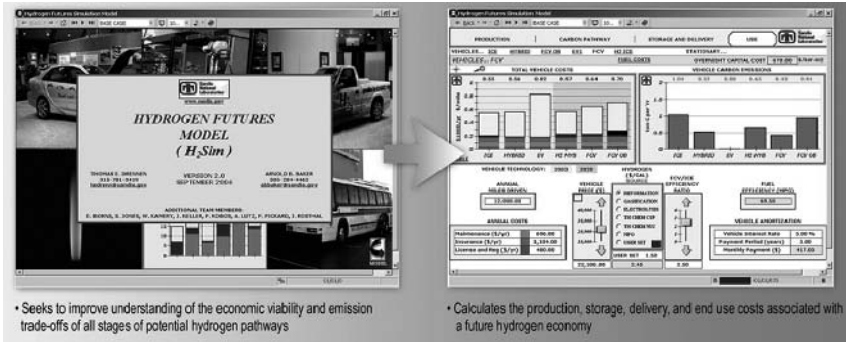


Figure 1.4. The Hydrogen Futures Simulation Model.

parties in evaluating the economic and environmental trade-offs of alternative hydrogen production, storage, distribution, and end-use options (Figure 1.4). For each option, the base case assumptions use projected cost and performance estimates for 2020, as reported in the literature, or as estimated by experts at Sandia National Laboratories.<sup>7</sup>

## Production

H<sub>2</sub>Sim considers six hydrogen production options: steam methane reformation (SMR), coal gasification, electrolysis, NPO of crude oil, and thermochemical processes from nuclear or concentrated solar power (CSP) technologies. Some of these production technologies are available commercially already (SMR, gasification, NPO, and electrolysis), whereas thermochemical processes are potential future options. Certain technologies such as coal gasification and the thermochemical processes only make sense for large-scale, centralized hydrogen production, while others could be used either as centralized or as decentralized, small-scale solutions to hydrogen production (SMR and electrolysis). As the results of H<sub>2</sub>Sim depend on projected costs and performance characteristics in 2020, there is considerable uncertainty associated with the results. H<sub>2</sub>Sim provides a consistent and transparent method for exploring the sensitivity of the results.

Globally, about 16 trillion cubic feet (ft<sup>3</sup>) of hydrogen are used in the chemical and manufacturing sector [National Academy of Sciences

<sup>7</sup> Modeling team included: A. Baker, D. Borns, T. Drennen, S. Jones, W. Kamery, J. Keller, P. Kobos, A. Lutz, P. Pickard, and J. Rosthal.

(NAE) 2004]. Hydrogen is used in the manufacture of ammonia ( $\text{NH}_3$ )-based fertilizer, in refinery operations to convert heavy oil into more useable forms (hydrocracking), and in various reformulated gasoline blends that meet local air pollution standards. Hydrogen also is added routinely to unsaturated fats, such as margarine, to make them spreadable and to increase shelf life. The NAE (2004) study estimates that of this global total of hydrogen used, 48% is derived from natural gas, 30% from oil, 18% from coal, and 4% from electrolysis.

### **Production Options**

The reformation of natural gas involves steam heating the natural gas under pressure in a catalytic reactor, which results in hydrogen and carbon dioxide. The same basic process can be used to produce hydrogen from other feedstocks, such as biomass. SMR is an option for either large-scale centralized facilities or small-scale decentralized facilities, such as the fueling station or even the home. While production economics favor larger, centralized plants, decentralized plants eliminate or greatly reduce distribution and storage costs.

Coal gasification also utilizes high temperatures and pressures to separate hydrogen from the feedstock. Unlike steam reforming technologies, coal gasification only makes sense as a centralized production option due to economies of scale. It is simply not feasible to place gasification units at fueling stations. Proponents of this option argue that for countries with large coal reserves, such as the United States, India and China, coal gasification, along with sequestration of the carbon, may be the least expensive and most attractive option for the large-scale supply of hydrogen (Williams 2001). These facilities could be placed at coal mines, eliminating the need to transport the coal. This is an important consideration in China, where demand for rail capacity now outstrips supply.

Electrolysis is a commercially viable technology for producing hydrogen and is used today to produce pure oxygen for such places as hospitals and submarines. The basic process is well known: by placing positive and negative electrodes in water, the water is disassociated into hydrogen and oxygen. Electrolyzers offer a good decentralized option for producing hydrogen and could be placed at fueling stations or even in the home. The main cost is electricity. Electricity costs are projected within  $\text{H}_2\text{Sim}$  for a variety of sources including coal, natural gas, nuclear, and renewable sources. Proponents of electrolysis suggest the use of cheap, off-peak electricity to produce hydrogen. While this may be an option for small-scale production, wide-scale use of electrolysis would require the construction of significant additional generation capability.

Furthermore, off-peak electricity is only cheap when demand for it is low; increased demand for hydrogen production would increase the price of electricity.

Another method of production, widely used by refineries, is partial oxidation of hydrocarbons such as crude oil or natural gas. The basic process requires temperatures of 1200–1450°C and pure oxygen. Most of the hydrogen produced in this manner currently is used by the refiners themselves for treating heavier grades of petroleum.

Thermochemical processes involve the use of high-temperature heat from either nuclear or CSP to disassociate hydrogen from water molecules. Over 100 thermochemical cycles for hydrogen production have been identified. One of the most promising cycles is the sulfur-iodine (S-I) cycle.<sup>8</sup> A key advantage of the S-I cycle is that the chemicals all are recycled; there are no effluents. The challenge is that the process requires very high temperatures (800°C) and still is in the experimental stages.

## Hydrogen Production Costs

The base case hydrogen production costs for each of these options in 2020, as calculated using H<sub>2</sub>Sim, are summarized in Table 1.2. The results are expressed in terms of dollars per kilogram (\$/kg); a kilogram of hydrogen is roughly equivalent to a gallon of gasoline in terms of energy content.<sup>9</sup> These results suggest that hydrogen could be produced

Table 1.2. H<sub>2</sub>Sim base case hydrogen production cost results.

	Production cost (\$/kg)
Steam methane reformation	1.43
Coal gasification	0.81
Electrolysis <sup>1</sup>	2.33–12.43
Thermochemical CSP	2.12
Thermochemical nuclear	1.50
NPO	1.73

<sup>1</sup> Depends on the electrical generating source used. Lower end assumes use of coal and upper end is for solar PV.

<sup>8</sup> The basic process involves combining water with sulfur dioxide and iodine at temperatures of approximately 120°C to form H<sub>2</sub>SO<sub>4</sub> and HI. The HI can then be disassociated at 450°C to produce iodine and hydrogen. The H<sub>2</sub>SO<sub>4</sub> is then recycled by heating at 800°C to produce oxygen, sulfur dioxide, and water.

<sup>9</sup> The exact conversion is 1 kg H<sub>2</sub> = 0.96 gallons gasoline, on a lower heating value basis.

for as low as 0.81 \$/kg from coal gasification. Hydrogen production costs from electrolysis range from a low of 2.02 \$/kg to a high of 12.43 \$/kg. This wide range depends on the source of the electricity. The lower range assumes 4.5 cents/kWh electricity from newly constructed base load coal generating facilities, while the higher estimate assumes 26 cents/kWh electricity from a solar photovoltaic system. Hydrogen produced from the SMR process is the second cheapest at 1.41 \$/kg.<sup>10</sup> As will be discussed, this result is highly sensitive to the price of natural gas.

A key rationale for moving to a hydrogen economy is to minimize carbon emissions. Producing hydrogen from coal actually could result in increased carbon dioxide emissions, unless carbon capture and sequestration is an integral part of these plants.

### **Carbon Capture and Sequestration**

Minimizing CO<sub>2</sub> emissions from the production of hydrogen from hydrocarbons (coal, natural gas, and oil) requires separating the carbon stream during the production process and then transporting the CO<sub>2</sub> to a suitable site, such as geologic formations or the deep ocean, where a large percentage of the CO<sub>2</sub> will remain indefinitely. CO<sub>2</sub> already is injected routinely into partially depleted oil wells as a technique to enhance oil recovery. This process has not, however, demonstrated the long-term viability of carbon storage. One of the largest projects involves piping the CO<sub>2</sub> 800 km from southwestern Colorado to West Texas. Several ongoing demonstration projects in the United Kingdom and elsewhere are testing the viability of deep ocean disposal.

Fortunately, capturing CO<sub>2</sub> during the hydrogen production process is simpler than is the case for capturing CO<sub>2</sub> associated with electricity production. Recent estimates of those capture costs range from \$54 per ton of carbon (\$/tC) for integrated gas combined cycle (IGCC) plants to 110 \$/tC for pulverized coal facilities (EPRI 2000). Such costs would add significantly to the costs of generating electricity. This has implications for hydrogen production using electrolysis as well. A 50 \$/tC charge would increase the cost of electricity from IGCC and coal facilities by 1.16 and 0.49 cents/kWh, respectively (Drennen et al. 2003).

Technically, it is far simpler to remove the CO<sub>2</sub> from either natural gas reformation or coal gasification as the carbon already is being separated from the hydrogen. Estimates of the technically recoverable CO<sub>2</sub> range from 87% (Williams 2001) to 92% (NAE 2004). Williams

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<sup>10</sup> Assumes a natural gas cost of 5.92 \$/MBtu; each \$1 increase in natural gas price increases the cost of produced hydrogen by \$0.16.

estimates increased capital costs of around 15% for the equipment to capture the CO<sub>2</sub> that otherwise would be vented.<sup>11</sup> H<sub>2</sub>Sim relies on methodologies outlined by Ogden (2002), Williams (2001), and the NAE (2004). Ogden's analysis considers carbon capture from large-scale hydrogen and electricity facilities utilizing either natural gas or coal as a feedstock. For the SMR facility, Blok et al. (1997) estimate that 70% of the CO<sub>2</sub> can be captured with an increased capital cost of 2.8%. Beyond that, the capital costs increase significantly. Williams estimates an 84% removal rate will increase capital costs for the SMR facility by 32%.<sup>12</sup> Once captured, the CO<sub>2</sub> must be transported to the eventual storage site and injected into wells.

Carbon capture and sequestration costs add \$0.16 to each kilogram of hydrogen produced by coal gasification, and from 0.09 to 0.22 \$/kg-H<sub>2</sub>, depending on the percentage of CO<sub>2</sub> removed, for hydrogen produced by natural gas reformation. These results do not change the fundamental order of the production costs. Coal gasification remains the cheapest option for producing hydrogen. There is, however, considerable uncertainty about sequestration possibilities. Ongoing demonstration projects must establish the long-term viability of storing large amounts of carbon produced from the production of hydrogen.

### **Distribution and Storage**

Most hydrogen pathways will require hydrogen storage both at the production and the end-use (fueling station) site. For hydrogen produced at centralized facilities, the hydrogen must be delivered to the fueling station. Depending on the delivery method, there may be storage costs at both the production facility and the fueling stations. The cost of getting the hydrogen to the fueling station can be quite expensive. This is a key issue that must be resolved before the hydrogen economy can become a reality.

A wide variety of options exist for transporting hydrogen, ranging from gaseous or liquefied truck transport to large-scale pipelines. Getting the hydrogen to the end-use site may require multiple modes of transport, including large regional pipelines that connect to smaller, local pipelines or to trucks, ships, or rail cars. H<sub>2</sub>Sim considers a variety of options for the transportation of hydrogen. Each includes the likely storage choice most suitable for that transport option. As an example, one includes underground, gaseous storage of hydrogen in caverns,

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<sup>11</sup> Williams also estimates a 2.6% efficiency penalty associated with the carbon capture.

<sup>12</sup> Assumes energy efficiency penalty of 3%.

with large pipelines (9–14 inch) carrying the gaseous hydrogen to a series of smaller, local pipelines (2–4 inch) which deliver the hydrogen to a fueling station that includes gaseous storage tanks.

Hydrogen can be stored as a compressed gas, a liquid, or even within the lattices of certain metals (metal hydrides). Each option has different costs and issues. Hydrogen gas can be stored above ground in tanks or below ground in caverns. Hydrogen's low volumetric density makes significant compression a requirement. Car manufacturers, for example, are considering onboard tanks at 5000–10 000 psi. Liquefaction greatly reduces storage space requirements, but requires very low temperatures ( $-253^{\circ}\text{C}$ ) to prevent boil-off, which occurs when the hydrogen reaches a temperature at which it evaporates into a gaseous state (Amos 1998). Metal hydrides provide a solid-state storage option in which hydrogen is absorbed into the lattice of a metal such as iron-titanium (FeTi) (Padró and Putsche 1999). Absorbing hydrogen into the metal requires cooling. Conversely, heat is required to release the hydrogen. Metal hydrides are not yet a commercially viable option. Current metal hydride storage technology allows for approximately 4–5% storage by weight. Ovshinsky (2003) estimates that the storage ratio needs to increase to approximately 7% before metal hydrides storage is a viable alternative. This soon may be a reality. Researchers at Stanford announced in 2006 that they've developed metal organic frameworks (MOFs) that can store 7.5% hydrogen by weight at ambient air temperatures (Energy Daily 2006).

Hydrogen distribution options included in  $\text{H}_2\text{Sim}$  are truck or rail (gaseous, liquefied, metal hydride), ship (liquefied), and pipeline (gaseous). The cost of hydrogen distribution is dependent on two primary factors: transport rate and distance. Some transportation options make sense for short distances and low transport rates, such as truck transport. Others, such as pipelines, are more feasible in the case of a fully developed hydrogen economy. Hydrogen's low volumetric density means that a truck can only transport roughly 180 kg of compressed hydrogen per trip, or the energy equivalent of approximately 180 gallons of gasoline (Amos 1998). Large-scale transport of hydrogen in this method, even if it made economic sense, would greatly increase truck traffic on the highways. This simply is not workable on a large scale.

### **Delivered Hydrogen Costs**

The cost of delivered hydrogen is the sum of the production, storage, and transportation costs. Tab 1.3 summarizes delivered hydrogen costs for a wide range of production methods and three of the most often

Table 1.3. Estimated delivered hydrogen costs.

Production method	Production cost (\$/kg)	Delivered Cost (\$/kg) <sup>1</sup>		
		Storage & Delivery methods <sup>2</sup>		
		Underground pipeline-large pipeline-local	Gaseous truck-gaseous none	Liquid truck-liquid none
Reformation	1.43	2.16–4.00	3.04–6.85	2.37–2.39
Gasification	0.81	1.54–3.38	2.42–6.23	1.75–1.77
Electrolysis	2.80	3.53–5.37	4.41–8.22	3.74–3.76
Therm-CSP	2.12	2.85–4.69	3.73–7.54	3.06–3.08
Therm-Nuclear	1.50	2.23–4.07	3.11–6.92	2.44–2.46
NPO	1.73	2.46–4.30	3.34–7.15	2.67–2.69

<sup>1</sup> Costs range from a flow rate of 100 000 kg/day and delivery of 100 miles to 1 000 000 kg/day and 500 miles.

<sup>2</sup> Scenarios written Storage/Delivery/Local Delivery. End storage not included.

mentioned delivery options. These three options are underground storage with regional and local pipelines; gaseous storage and truck transport; and liquid storage and truck transport. These costs do not include carbon capture, sequestration, or estimated fueling station costs.

For each option, Table 1.3 includes estimated 2020 delivery costs for a low-distance, low-production rate (100 miles, 100 000 kg/day) and a long-distance, high-production rate (1000 miles, 1 000 000 kg/day). For example, for H<sub>2</sub> produced from coal gasification and delivered via pipelines, estimated costs range from 1.54 \$/kg for the low-distance, low-production case to 3.38 \$/kg for the long-distance, high-production case. Fueling station costs may be quite significant. H<sub>2</sub>Sim assumes fueling station costs range from 0.41 \$/kg for gaseous storage and dispensing to 0.50 \$/kg for liquid storage and dispensing. Other sources, including Ogden (1999), suggest that such costs could add as much as 0.52–0.78 \$/kg to the costs presented here.

Table 1.3 also emphasizes the large contribution of distribution costs to total hydrogen costs. The use of distributed hydrogen production, such as natural gas reformers or electrolyzers at the fueling stations, would eliminate the distribution costs. However, smaller units may not capture the economies of scale associated with larger units. On the basis of the results of H<sub>2</sub>Sim, the least-cost distributed option would be SMR (1.86 \$/kg).<sup>13</sup> Distributed electrolysis options are considerably

<sup>13</sup> This result is highly dependent on the cost of delivered natural gas. Each \$1 increase in delivered natural gas cost increases the estimated hydrogen cost by 0.16 \$/kg.

more expensive (2.92–6.58 \$/kg). An alternative in the early phases of a hydrogen economy appears to be liquefied storage and truck transportation, with delivered cost estimates ranging from 1.75 to 1.77 \$/kg.

Clearly, hydrogen distribution costs may be significant, suggesting that the future viability of a hydrogen economy may depend on achieving reductions in these storage and transportation costs.

The National Academy of Engineering (NAE) (2004) reached a similar conclusion. Specifically, they found that pipeline shipment and dispensing would be the lowest cost option, at 0.96 \$/kg, "... which is essentially equal to the cost of production." The NAE concludes that "even with possible future improvements in shipping and distribution, this cost is much more than today's gasoline dispensing and distribution costs, at 0.19 \$/gal." The NAE notes that this analysis "demonstrates the realities of shipping H<sub>2</sub> gas versus the much more efficient shipment of a liquid."

## End Use

The final component of H<sub>2</sub>Sim considers end-use options for hydrogen, mainly in the transportation sector. H<sub>2</sub>Sim compares the end-use cost in 2020 of using hydrogen in either FCVs or a hybridized internal combustion engine that combusts hydrogen rather than gasoline (H<sub>2</sub>Hybrid) in 2020 with existing ICE, hybrid, and electric (EV) vehicles. It also considers a 2020 FCV with on-board production of hydrogen (FCV OB).

These vehicles are compared in terms of total cost per mile based on assumptions about vehicle price; maintenance, insurance, license, and registration costs; and associated fuel costs. Table 1.4 summarizes

Table 1.4. Vehicle price and efficiency assumptions and estimated operating costs.

Vehicle	Vehicle cost (\$)	Efficiency (mpg)	Total cost (\$/mile)
ICE	18 000	27.8	0.55
Hybrid	19 736	55.0	0.56
EV <sup>1</sup>	33 995	46.3	0.82–0.88
H <sub>2</sub> Hybrid <sup>2</sup>	18 000	45.0	0.56–0.61
FCV	22 100	69.5	0.64–0.67
FCV OB	25 910 <sup>3</sup>	61.0	0.70

<sup>1</sup> Ranges from least expensive to most expensive electricity production options; does not include T&D costs.

<sup>2</sup> Ranges from least expensive to most expensive hydrogen production options; assumes distribution option 1.

<sup>3</sup> Includes a vehicle cost of \$22 100 and a reformer cost of \$3810.

the key assumptions and the total operating costs for each vehicle as estimated by H<sub>2</sub>Sim.

For the case of the least expensive hydrogen production option (coal gasification) with pipeline transportation, the H<sub>2</sub>Hybrid vehicle is the least expensive hydrogen vehicle to operate overall (0.54 \$/mile) and is competitive with today's ICE vehicles (0.55 \$/mile). A FCV, with a base efficiency 2.5 times a comparably sized ICE vehicle and costing \$4100 more, has an estimated operating cost of 0.62–0.70 \$/mile, at least seven cents higher than the ICE vehicle. Hybrids already are competitive with ICE vehicles. The electric vehicle and the 2020 FCV with onboard reformation have the highest end-use costs due to battery costs for the electric vehicle and the onboard reformer cost for the FCV, which adds almost \$4000 to the vehicle cost.

### **Carbon Emissions**

One of the potential benefits of hydrogen is a decrease in carbon emissions, thought to be the leading anthropogenic contributor to global climate change. Conventional ICE vehicles emit approximately 1.04 tons of carbon (tC) annually, based on default assumptions about efficiency and miles driven. Hydrogen vehicles offer the potential for zero carbon emissions if the hydrogen is produced using electrolysis from a non-carbon emitting source or a thermochemical process. Hydrogen produced using coal gasification or SMR will result in significant carbon emissions unless these options include carbon capture and sequestration.

Estimated annual carbon emissions by vehicle type and fuel source are summarized in Table 1.5. Existing hybrid vehicles emit half as much carbon as current internal combustion engine vehicles, explainable by the difference in assumed fuel efficiencies. For the EV, annual carbon emissions depend on the source of the electricity. Annual estimates range from zero for non-carbon based electricity sources to 0.58 tons per year if coal is used to produce electricity. Estimated carbon emissions for the various future technologies depend on the source of hydrogen and whether the carbon is captured and sequestered. In the absence of carbon sequestration, carbon emissions may be greater than those from existing hybrid vehicles. A FCV using hydrogen produced from coal gasification without carbon capture and sequestration would emit about 0.75 tC per year. With carbon sequestration, the same FCV would release 90% less than existing vehicles (0.10 tC per year). If fueled with hydrogen from electrolysis using carbon-based electricity, annual emissions actually would be greater than existing vehicles (1.57 tC/year), illustrating that wide-scale adoption of FCVs does not guarantee lower carbon emissions.

Table 1.5. Estimated annual carbon emissions by vehicle type.

Vehicle/fuel option	Carbon emissions (metric tons C/yr)
ICE	1.04
Hybrid	0.52
EV <sup>1</sup>	0.00–0.58
H <sub>2</sub> Hybrid	
Steam methane reformation <sup>2</sup>	0.65/0.11
Coal gasification <sup>2</sup>	1.16/0.16
Electrolysis <sup>1</sup>	0.00–2.42
Thermochemical CSP	0.00
Thermochemical nuclear	0.00
NPO	1.74
FCV	
Steam methane reformation <sup>2</sup>	0.42/0.07
Coal gasification <sup>2</sup>	0.75/0.10
Electrolysis <sup>1</sup>	0.00–1.57
Thermochemical CSP	0.00
Thermochemical nuclear	0.00
NPO	1.13
FCV OB	0.82

<sup>1</sup> Depends on generating source. Lowest levels are from Nuclear, Solar PV, Solar Thermal, and Wind. Highest emissions are from coal.

<sup>2</sup> Carbon emissions written Carbon emissions without sequestration/Carbon emissions with sequestration.

## Sensitivity of the Results

H<sub>2</sub>Sim suggests that coal gasification is expected to be the lowest-cost hydrogen production option (0.81 \$/kg) in 2020. This basic result does not change if carbon capture and sequestration costs are added (0.15 \$/kg). This result is fairly robust. Coal prices would have to quadruple or the assumed capital cost would have to increase by more than 2.5 times for natural gas reformation to become the cheaper option. Alternatively, natural gas prices would have to fall below \$2 per million British thermal units (\$/MBtu) to compete with coal gasification. The electrolysis results are highly sensitive to electricity costs. Most importantly, electrolysis only becomes cost competitive with other options when electricity drops below 1 cent/kWh. While the possibility might exist to purchase some off-peak electricity for 1 cent/kWh, the use of the hydrogen plant's capacity would fall substantially and the higher fixed expenses could more than offset the reduced electricity costs.

Press reports and public policy discussions tend to focus on the delivered price of hydrogen compared to gasoline. But since hydrogen fuel is not a substitute for gasoline in existing ICE vehicles, this may be a poor comparison. What's usually overlooked is that the fuel cost is a

very small portion of total end-use cost, especially during the first few years of a car's life. H<sub>2</sub>Sim suggests that it will be difficult for FCVs to compete with ICE vehicles on a cost-per-mile basis, regardless of FCV efficiency. Furthermore, H<sub>2</sub>Sim uses existing vehicle characteristics for the base analysis. ICE and hybrid technologies also will improve over this time period. Weiss et al. (2000) predict that ICE vehicles will have an average efficiency of 43 miles per gallon (mpg) in 2020 (rather than the 27 mpg assumed here). Using the default assumptions about vehicle costs and the least expensive delivered hydrogen (coal gasification with pipeline transportation), FCVs can't compete at any conceivable efficiency. The fuel cost component is simply too insignificant in comparison to the other assumptions. The anticipated price of the vehicle really drives the economics. For the assumed efficiency of the FCV in 2020, the FCV vehicle cost would have to fall below \$17 400 to be competitive with today's ICE vehicles. The analysis does suggest that H<sub>2</sub>Hybrid vehicles may make more economic sense than FCVs. It also suggests that onboard reformation of gasoline to fuel a FCV makes little economic sense.

The other key variable that affects the results is the price of gasoline (Figure 1.5). H<sub>2</sub>Sim assumes a wholesale price of gasoline<sup>14</sup> in 2020

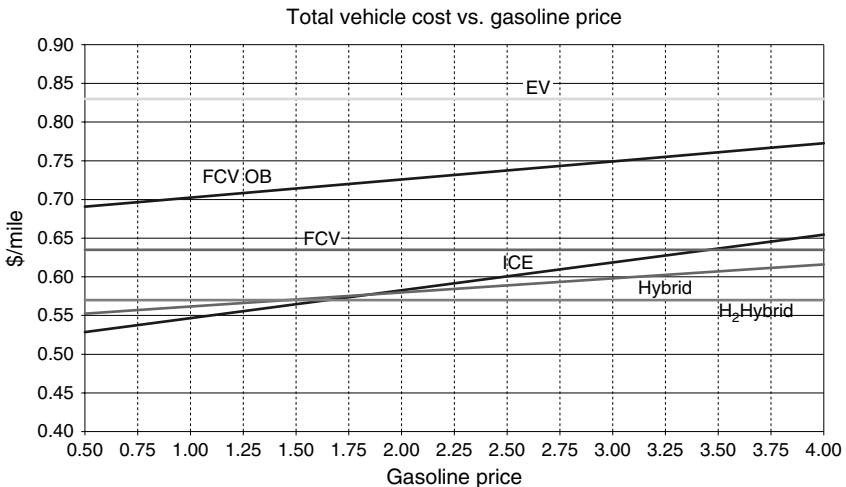


Figure 1.5. Sensitivity of results to gasoline prices (default results assume 0.99 \$/gallon gasoline).

<sup>14</sup> In 2004 the Federal tax on gasoline is 18.4 cents/gallon, and the weighted average state tax is 19.25 cents/gallon (FHA 2004).

of 0.99 \$/gallon (2003 dollars). The sensitivity analysis shows that for today's ICE technology vehicle at 27 mpg, gasoline prices, either as a result of market forces or government intervention, would have to approach 3.80 \$/gallon before the 2020 FCV would be competitive. For the H<sub>2</sub>Hybrid, the breakeven gasoline price is 1.75 \$/gallon.

## **Conclusion**

Compelling reasons for moving to a hydrogen economy abound in today's demanding, developing global societies. Surging worldwide growth in energy consumption raises concerns about resource availability, energy security, and environmental degradation. The use of hydrogen can alleviate some of these problems, but will depend, in large part, on the chosen pathway. While some sources of hydrogen (electrolysis using wind) would reduce reliance on hydrocarbons, other choices (NPO, onboard reformation) would not. Some options (electrolysis from coal) might increase carbon emissions from vehicles.

Experts have suggested competing visions for developing the hydrogen economy. A major hurdle is the chicken-and-egg problem: fueling stations will not provide hydrogen until sufficient demand exists, and consumers will not buy hydrogen vehicles unless they know hydrogen is available. In the early stages of the transition to a hydrogen economy, one option is to use FCVs with onboard reformation of gasoline. The results from H<sub>2</sub>Sim, however, suggest that these FCVs could not compete economically with ICE vehicles. Nor would this option solve the many problems associated with oil consumption. An alternative that could provide either a transitional or long-term strategy is decentralized production of hydrogen at the home or fueling station. This would eliminate the need for an extensive hydrogen delivery system. Initial results from H<sub>2</sub>Sim suggest end-use costs would be slightly higher than for centralized production. Finally, in the mature stages of the hydrogen economy, H<sub>2</sub>Sim illustrates that centralized production is the most cost effective method of hydrogen production and distribution. This option allows for a greater diversification of resources and the possibility of carbon sequestration to prevent increased emissions of greenhouse gases.

While a great deal of focus is placed on the production and distribution of hydrogen, H<sub>2</sub>Sim illustrates that reducing projected FCV prices, either directly or through the use of tax incentives, is key to making FCVs cost competitive. The results also suggest that an H<sub>2</sub>Hybrid could compete with traditional engines in 2020, offering a possible transition or alternative technology. Another option is to raise the operating cost of ICE vehicles by increasing gas prices with taxes to explicitly account for the external costs associated with the consumption of oil.

In the absence of additional cost reductions, tax credits, or gasoline taxes, H<sub>2</sub>Sim suggests that FCVs in 2020 would cost about 7 cents more per mile to operate than ICE vehicles. Consumers may not be willing to bear that price unless FCVs provide additional services or benefits that traditional ICE vehicles cannot, such as better performance, remote power applications, or lower emissions. Finally, although H<sub>2</sub>Sim concludes that FCVs will have a tough time competing economically with ICE vehicles, the model does suggest that FCVs provide an opportunity to greatly reduce carbon emissions from the transportation sector if hydrogen is produced from a non-carbon emitting source.

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Part II

**Why Hydrogen?**

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# Chapter 2

## Justifications for Hydrogen

Conventional wisdom has long told us that energy supplies are sufficient to meet demands for energy, even as those demands began to soar worldwide.

But a potential new type of conventional wisdom has governments, automobile manufacturers, and even oil companies exploring the hydrogen option. This tactical change is due to

- Soaring worldwide growth in energy demand and recognition that fossil fuels are a limited resource;
- Concerns about the overall security of our existing energy infrastructure;
- An increased awareness of local and global environmental impacts of our current patterns of energy use.

### Growing Energy Consumption

Like food and water, energy is a fundamental human need. At the most basic level, we use energy to keep us warm and to prepare the food that sustains us. We have grown dependent on energy to plant and harvest our crops, to keep us warm in the winter and cool in the summer, to provide light at night, to transport us from one place to another, and to run the factories and stores that provide us with important goods and services. The oil and natural gas price shocks of 2004–2005 serve as sharp reminders of our overall vulnerability to supply shocks, whether due to supply manipulations (producer cutbacks or terrorist activities) or natural disasters.

Current energy-use projections suggest a continued reliance on fossil fuels and assume little or no penetration of hydrogen options. But because these forecasts are often just based on current trends, they also are inevitably wrong. They fail to consider as yet undiscovered technologies or the effects of possible future geopolitical events, such as a

sudden collapse of the Saudi government or UN-imposed sanctions on Iran for its unwillingness to allow outside inspection of its nuclear program. While long-term forecasts help policy-makers and others be aware of possible outcomes, such as a projected 55% increase in oil demand by 2025, they should not be viewed as the way things have to be. As an example of how quickly forecasts become outdated, the 2006 projections of the US Department of Energy for long-term oil prices predict prices in 2025 will be \$21 per barrel higher than its 2005 prediction. Figure 2.1 shows a range of forecasts for future oil prices made at different times over the past several decades. This graph shows that future oil price projections often are driven by current prices.

And who knows? As with the large changes in predicted oil prices illustrated in Figure 2.1, some unforeseen event could lead to a rapid reevaluation of our current supply projections. It may be that a country with vast coal reserves, such as China – recognizing the inherent national security issues associated with a growing demand for oil – would be the first country to have cars fueled with hydrogen produced from coal.

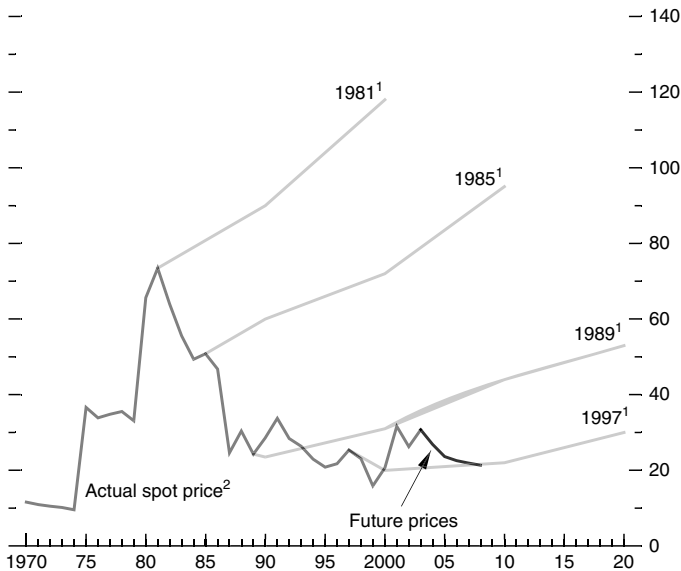


Figure 2.1. Past forecasts of oil prices.

(Sources: Bloomberg Financial Markets, LP; Goldman Sachs (2002); and IMF staff estimates.)

<sup>1</sup> Average of long-term forecasts prepared by the US Department of Energy and the International Energy Workshop in 1981, 1985, 1989, and 1997, respectively.

<sup>2</sup> West Texas Intermediate petroleum spot price.

Far fetched? Maybe, but then again, history is full of examples of shocks to the status quo, where countries or companies just did not understand the competition. American car companies have failed repeatedly to grasp the threat posed by imports. The launch of Sputnik in 1957 shocked the world because no one thought the Soviets had the technological know-how to build rockets. The realization that we were wrong sent the United States and others scrambling to play catch up. And while car companies have long eyed the huge Chinese market, China announced in 2006 its intention to market low-cost vehicles to the rest of the world.

### Fueling the World

Historical and projected energy demand in the world is summarized in Figure 2.2. Total worldwide demand reached 417 quads [quadrillion British Thermal Units (Btus)] in 2003,<sup>1</sup> up from 348 quads in 1990, a 20% increase (EIA 2005b). The Department of Energy predicts that total demand will reach 645 quads by 2025, a further 54% increase (EIA 2006c). Figure 2.2 also illustrates expected trends. While energy demand is expected to increase, fuel shares remain fairly constant. The share of global primary energy demand provided from fossil fuels remains at

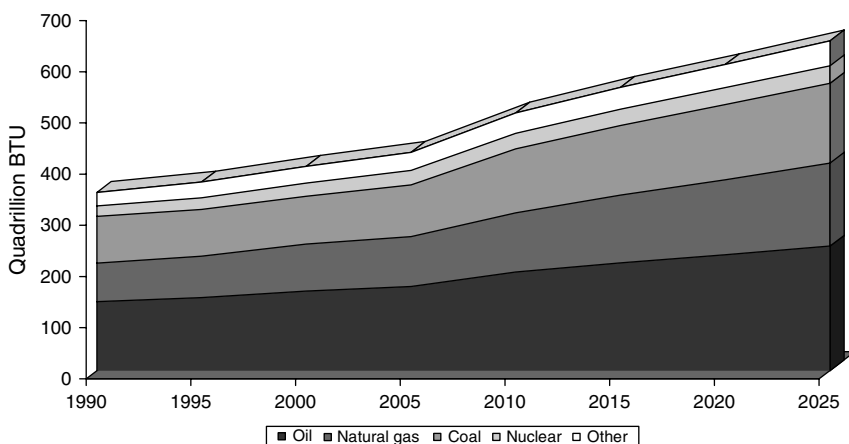


Figure 2.2. Historical and projected world energy consumption, 1990–2025.  
(Sources: EIA 2005b, 2006c.)

<sup>1</sup> 1 quad =  $1 \times 10^{15}$  BTU = 1.055 EJ. One quad is enough energy to keep 557 million 60-W light bulbs lit for 1 year.

about 86%. Of that, oil's share is constant at just under 40%, natural gas' share increases from approximately 22–25%; and coal's share decreases slightly, from 26 to 24%. Likewise, nuclear energy remains relatively constant, dropping from 5.8 to 5.3% over the forecast period. Finally, the overall market share of energy from renewable resources remains fairly small, at just under 8%. Other oft-cited forecasts, such as those of the International Energy Agency (IEA), suggest similar trends over the next two decades: large increases in energy demand and a continued reliance on fossil fuels.

As global energy demand surges at an exponential rate, so do concerns about adequacy of energy supplies, environmental degradation, and world security. People and economies have become increasingly dependent on energy to function. Nowhere is this reliance more evident than in the United States. With about 5% of the world's population, the United States accounts for 25% of total world demand (EIA 2005a). Add in the other industrialized countries in the world, and the 966 million people in industrialized countries use more energy (52%) than the other 5.3 billion people in the world (EIA 2005a). And what the industrialized world has, the rest of the world wants.

For example, the sale of cars in China has exploded in recent years; sales of new cars increased 60% in 2004 (Gallagher 2006). Chinese consumers, just like every consumer in already developed countries, crave the freedom promised by owning a car. China's recent entry to the World Trade Organization (WTO) means reduced tariffs on imported vehicles and, for the first time, access to financing. By 2025, Kobos et al. (2003) predict as many as 125 million vehicles in China.<sup>2</sup> While a very large increase from current levels, this translates into about 75 cars for every 1000 people, well below current US levels of 724 cars per 1000 people (ORNL 2005) or Japanese levels of 590 per 1000 people (JITI 2005), and suggests there is still room for tremendous growth beyond the 125 million. Fueling these vehicles will require up to 6.1 mbd per day of oil, an increase of about 5 mbd – all of which will have to be imported.

A large part of the increased energy demand in the DOE forecast (Figure 2.2) over time is the near absolute reliance on oil for the transport sector. Total world oil demand is expected to increase from 77 mbd in 2003 to 119 mbd in 2025, a 55% increase (EIA 2006c). This growth is fueled not only by continued demand in the industrialized world, but also by the rapid growth of oil demand from developing countries (Figure 2.3). Of the 119 mbd demanded in 2025, 45% will be used

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<sup>2</sup>Kobos et al. (2003) forecast 64–125 million vehicles by 2025; other researchers predict higher numbers are possible. Ng and Schipper (2005) forecasts 120–160 million vehicles by 2030.

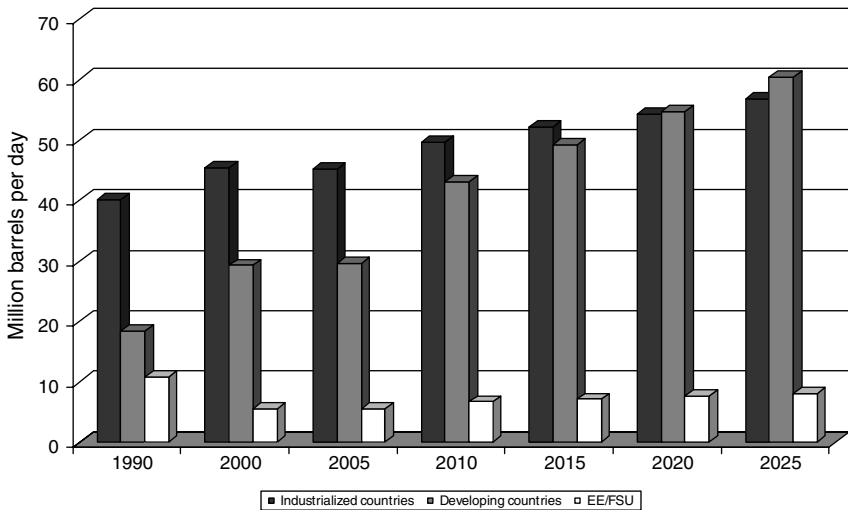


Figure 2.3. Historical and projected oil consumption by region, 1990–2025. (Source: EIA 2005a; EIA 2006a.)

by developing countries. This is in sharp contrast to the situation in 1990, when developing countries accounted for just 26% of total world demand (EIA 2005b). Note that this forecast predicts overall energy demand from developing countries will surpass demand from industrialized countries by 2020.

The electricity sector also will experience huge growth. An estimated 2 billion people lack access to electricity worldwide. The Department of Energy predicts electricity consumption will almost double from 2002 to 2025 (EIA 2006c). One-half of the projected growth is expected to occur in developing countries. Supplying this electricity will require huge investments in the electricity sector. According to calculations by Drennen,<sup>3</sup> meeting the increased demand in China will require the construction of the equivalent of 750 large [1000 megawatts (MW)] nuclear power plants by 2025, or 750 GW. Even if China expands its generating capacity that quickly, the country still would lag behind the United States in total installed capacity. The United States currently has 920 GW of installed capacity (EIA 2005a). Even with the new capacity and with a population four-and-a-half times as large as that of the United States, China's per capita energy consumption would be far below the average

<sup>3</sup> Estimate based on Sandia's China Energy and Greenhouse Gas Model. For more information, contact the author.

energy consumption level of the US. Building that number of plants would require large investments, but China has shown that it has the money to spend. China already is building power plants as rapidly as possible. Wang Yonggan, secretary general of the China Electricity Council (CEC), predicted 70 GW of new capacity would come online in China in 2005 (China Daily 2005), approximately equal to the existing electrical generating capacity of the United Kingdom.<sup>4</sup> While several countries in addition to China plan to add nuclear capacity, the vast majority of other future electricity plants are expected to rely on fossil fuels.

Worldwide, 430 nuclear plants generate about 17% of all electricity. In France, nuclear's share is 79%; in Japan it is 28%. Whereas there has not been a new nuclear plant ordered in the United States since 1978, there were 24 nuclear power plants worldwide under construction in 2005 (EIA 2006c). Many countries have ambitious plans to build more plants. China, with just nine plants currently in operation, plans on building as many as 25 new plants by 2025. Given the potential size of the Chinese market, reactor vendors from several countries are actively pursuing Chinese contracts, with the hope that China will use their designs for future plants.

Nuclear power is at a crossroads in the United States. While 104 nuclear power plants supply about 22% of US electricity and 8% of our total energy, the last new plant entered into service in 1995. The reference forecasts of the Department of Energy assume that no new nuclear plants will be built in the United States prior to 2025, leading to a decreasing market share for nuclear (16% in 2025) (EIA 2005a).<sup>5</sup> However, several industrial consortia are considering options for building new plants in the coming years.<sup>6</sup> And the recently enacted Energy Policy Act (EPACT) of 2005<sup>7</sup> provides significant financial incentives

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<sup>4</sup> The UK's capacity in 2003 was 74.9 GWe.

<sup>5</sup> DOE's reference forecast assumes existing plants will continue to operate throughout this time. Many older plants will receive plant uprates during the license renewal process.

<sup>6</sup> Three consortia have announced plans to proceed with seeking a construction and operating license for a new nuclear facility. They include: NuStart Energy (Duke Energy, Exelon, Entergy, Constellation Energy, Southern Company, EDF International, Florida Power and Light, Tennessee Valley Authority, Westinghouse, and General Electric), a Dominion led consortium (Dominion, AECL Technology, Hitachi America, Bechtel), and a TVA led consortium (TVA, GE, Toshiba, USEC, Global Fuels, and Bechtel). The NuStart group has selected six possible sites for building two new reactors, and will proceed with filing a construction and operating license with the NRC (NuStart, 2005). The cost of the COL will be cost shared 50-50 with the Department of Energy under its Nuclear 2010 program.

<sup>7</sup> The Energy Policy Act of 2005 was signed into law on 8 August 2005.

for new nuclear facilities, including various tax credits and insurance against regulatory delays.

Specifically, the EPACT provides a 1.8 cent per KWh tax credit for 8 years for electricity produced from new nuclear facilities, similar to the 10-year production tax credit available for qualifying renewable facilities.<sup>8</sup> This provision is available for the first 6GW of additional nuclear capacity, and plants must begin operation before 1 January 2021. To ease investor concerns about possible regulatory delays, the EPACT includes up to \$2 billion in insurance against delays. Specifically, the first two qualifying facilities can receive up to \$500 million per reactor for post-construction licensing delays; the next four facilities can receive up to \$250 million. The EPACT includes additional tax breaks for transferring funds into qualifying decommissioning funds and assurances that the government will continue to indemnify owners against major accidents through the Price-Anderson Act.

The newly enacted financial incentives for nuclear power in the United States will improve the overall economic viability of nuclear power. Whether new plants will be built still may hinge on other factors, including public attitudes toward nuclear power, the disposition of nuclear waste, and the overall regulatory environment.

Despite this growth, nuclear energy's share in the world electricity market is expected to remain fairly constant in the next couple decades due to remaining uncertainties, whether real or perceived, about the safety of nuclear and the handling of nuclear waste.

### *Fossil fuels – the low-cost option*

This historic and projected reliance on fossil fuels is largely due to economics. Fossil fuels are cheap and, at least for the near term, abundant. While oil prices certainly have fluctuated widely in the last three decades, oil was, until 2005, a relatively inexpensive resource. After adjusting for inflation, oil prices reached historical low levels in 1998, dropping below \$11 per barrel (Figure 2.4) (EIA 2006a). Prices since have rebounded for a variety of reasons, including turmoil in the Middle East, robust Asian demand, hurricane damage in the United States' Gulf Coast area during both the 2004 and 2005 hurricane seasons, and political instability in several non-Middle Eastern oil producing countries, including Venezuela, Nigeria, and Russia. Following the Gulf Coast's

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<sup>8</sup>The Act expanded the list of qualifying facilities, originally including wind, biomass, geothermal, rural irrigation power systems, landfill gas, trash combustion, and solar, to also include hydro and coal fired plants on Indian land. These facilities must be in operation by 31 December 2007.

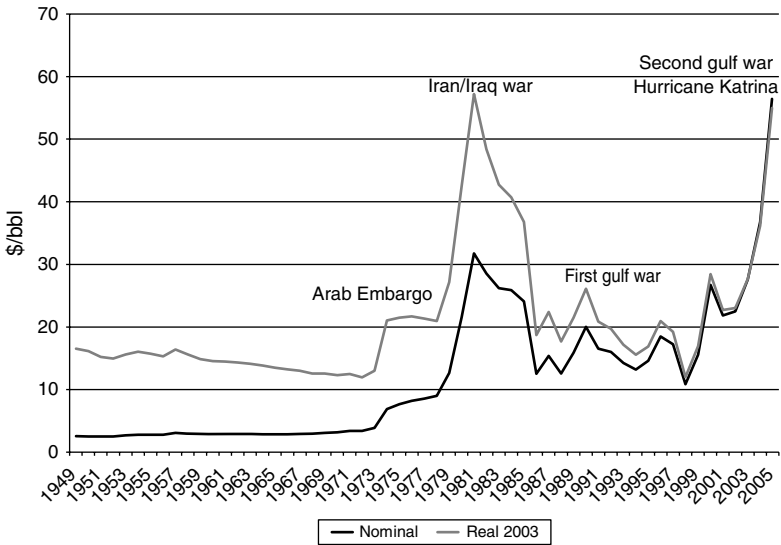


Figure 2.4. Nominal versus real crude oil prices, 1949–2005.  
(Source: EIA 2006a.)

Hurricane Katrina in August 2005, oil prices surged past \$60 per barrel, surpassing the previous peak price of \$57 per barrel. Somewhat mitigating these higher costs is that as income levels have grown, energy expenditures have become a smaller portion of total income. The average American in 1970 spent approximately 8% of total income on energy, a number that decreased to 6% by 1999, a year in which prices were nearly equal to the 1970 prices (EIA 2006a).

While natural gas has been widely used for residential heating for decades, it has only recently become the fuel of choice for generating electricity. Natural gas has many favorable characteristics for utilities: it is fairly easy to transport by pipeline; natural gas units operate at higher efficiency than coal or oil units; natural gas burns significantly cleaner than coal; and until recently (2004–2005), it was relatively inexpensive. As with oil prices, natural gas prices have risen precipitously in recent years (Figure 2.5) (wellhead prices). Natural gas prices reached as high as 14.80 \$/MBtu following the shutdown of several natural gas production facilities after Hurricane Katrina in 2005.<sup>9</sup> These increases may have long-term consequences for future decisions involving heating, industrial use, and electricity generation.

<sup>9</sup> Trading price for delivery at Henry Hub, 14 December 2005.

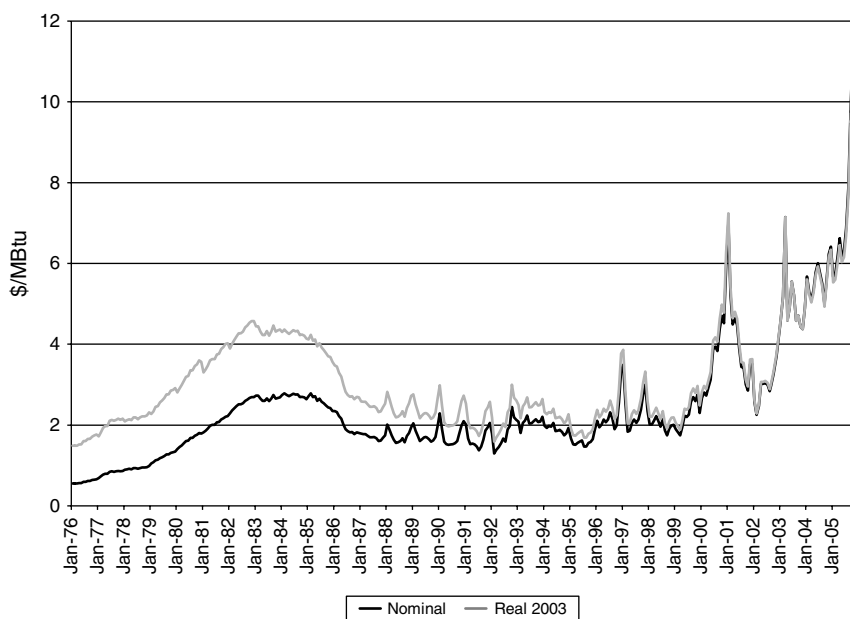


Figure 2.5. Nominal vs. real natural gas prices, monthly, 1976–2005.  
(Source: EIA 2006e.)

While many utilities had managed successfully the price volatility in natural gas markets through various financial mechanisms, including hedging and long-term contracts, the record high levels of 2005 forced utilities to reconsider coal, nuclear, or other options. This increase has a large impact on electricity production costs. Delivered natural gas prices to utilities averaged 5.57 \$/MBtu for 2003; by August 2005, the average utility cost reached 8.59 \$/MBtu.<sup>10</sup> Each \$1 increase in delivered natural gas prices increases the cost of producing electricity by about 0.67 cents/kWh. Therefore, for a utility with long-term natural gas contracts, the recent price increases translate into a 2.02 cents/kWh increase in the cost of production, from an estimated 5.23–7.25 cents/kWh.<sup>11</sup> Just as natural gas prices affect the price of electricity, they also affect the cost of residential heating. Following Katrina in 2005, the DOE warned

<sup>10</sup> Utilities actively hedge natural gas prices and/or have long-term contracts, which somewhat mitigates the impact of fast rising natural gas prices.

<sup>11</sup> These are projected production costs for a new, state of the art, electricity unit (2005). Production costs calculated using Sandia's Electricity Generation Simulation Model (GenSim). For further information, see Drennen et al. (2003).

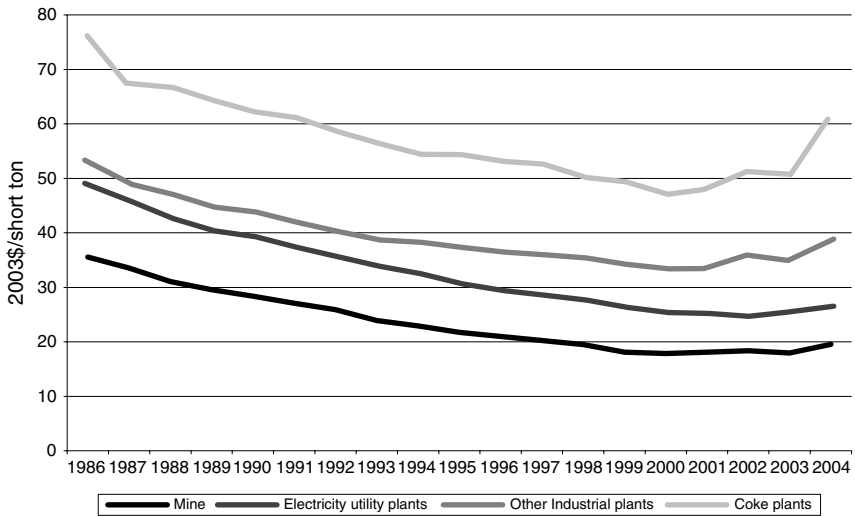


Figure 2.6. Coal prices for United States, 1986–2004.  
(Source: EIA 2006a.)

consumers that the average heating bill could increase by as much as 40% over the previous year. Perhaps more shocking is that residential prices have tripled in just 2 years (5.58 \$/MBtu in September 2003 to 16.60 \$/MBtu in September 2005).

US coal prices have increased somewhat due to rising transportation costs (Figure 2.6)<sup>12</sup>. However, the overall trend in coal prices as measured at the mine (mine mouth) is downward as coal producers continue to find ways to increase the productivity of the average mine. The average delivered price for utilities increased just 5.7% during 2004 (EIA 2004), but 13.2% for industrial users. The widespread use of futures contracts in the coal industry has helped to keep prices stable. The overall stability of coal prices likely also will lead to a renewed interest in coal by utility officials and others, who until recently, believed natural gas was the fuel of the future. Anecdotal evidence purports an increase in coal use at the residential level. Homeowners with access to delivered coal found it is possible to heat less expensively with coal than natural gas or oil in the 2005–2006 heating season (Kamery 2006).

<sup>12</sup>The United States Energy Information Administration reports free-on-board coal prices defined as “A sales transaction in which the seller makes the product available for pick up at a specified port or terminal at a specified price and the buyer pays for the subsequent transportation and insurance.” Prices, therefore, include a portion of the total transportation costs.

*Will fossil fuels remain the low-cost option?*

The DOE's long-term forecasts of future crude prices have increased significantly with its newest forecasts, the 2006 Annual Energy Outlook. In the 2005 forecasts, the DOE noted that despite the current high prices of oil, they expected significant downward pressures on those prices as uncertainty in the Middle East, such as in Iraq, were reduced, and as increased drilling led to increased production. The 2006 forecast is significantly less optimistic; for 2025, the 2006 forecast is \$21 per barrel higher than the 2005 forecast. In explaining the significant increases in long-term price trends, DOE notes that they now do not believe production capacity of OPEC countries can increase as quickly as previously thought, resulting in tight markets. By comparison, the IEA in its 2005 World Energy Outlook expected prices to fall back to the mid \$30 level by 2010 and then increase only slightly to \$39 by 2030. Their analysis assumes that markets will be tight through 2007, but thereafter they expect significant increases in production and refining capacity worldwide (Table 2.1).

Both DOE and IEA expect natural gas price pressures will ease significantly from 2005 levels and that prices will be in the 6 \$/MBtu range in 2030. These estimates assume that current drilling and exploration activities will lead to significant growth in production and that imports of liquefied natural gas will increase.

Likewise, both sources are optimistic about coal prices. The DOE expects that continued increases in mine productivity and the shift to low-cost coal from the Powder River Basin in Wyoming will lead to a gradual decline in mine mouth coal costs to approximately \$20 per ton in 2020.

*Increased fossil fuel demand will mean challenges*

Many troubling issues are associated with the forecast of rapidly increasing demand for oil, ranging from questions of resource availability to

Table 2.1. Comparison of forecasted fuel prices to 2020 by International Energy Agency (IEA) and US Department of Energy.

	2010		2020		2030	
	IEA	DOE	IEA	DOE	IEA	DOE
Crude oil (\$/bbl)	35.00	46.35	37.00	49.70	39.00	55.84
Natural gas (\$/MBTU)						
US	5.80	4.88	5.90	4.76	6.20	5.75
European imports	5.00		5.20		5.60	
Coal (\$/ton)						
OECD steam coal imports	44.55		45.45		46.36	
US Coal		21.60		20.06		21.70

local and global environmental concerns associated with the burning of fossil fuels. For example, like the United States, many developing countries such as China do not have adequate domestic supplies of oil to meet growing demands. The increased demand from all countries will lead to growing reliance on those countries with oil reserves and likely lead to new geopolitical challenges over oil supply. Locally, increased oil use in many countries will lead to amplified threats to local air quality. At the global level, as countries attempt to deal with the threats of global climate change, the drastic increases in energy use in developing countries will greatly complicate efforts to minimize greenhouse gas emissions.

None of this is meant as a criticism of the developing world for wanting what the rest of the world already has. Rather, it highlights some of the difficulties facing the world in the coming years. As developing countries grow economically, they will consume more energy. The challenge is figuring out how to supply that energy in a manner that allows for maximum growth while minimizing overdependence on resources that are scarce and that pollute the environment.

Figure 2.7 illustrates the basic relationship between per capita income levels and energy use. As personal incomes grow, energy demand grows. It also illustrates disparities among countries at similar stages of development. Americans, for example, consume a much larger amount

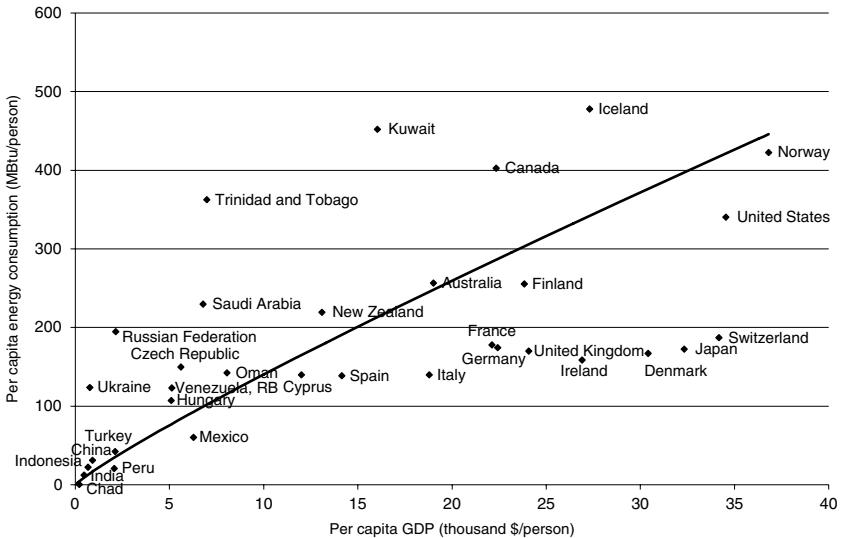


Figure 2.7. Relationship between income levels and energy consumption. (Source: World Bank 2004; EIA 2005b.)

of energy per person than do Europeans, with the exception of Norway. There are many reasons for these disparities, ranging from significantly higher gasoline taxes in European countries, reflecting differences in policies regarding the role of the personal car, to considerable differences in population density. Distances between major population centers in the United States are greater than they are in European countries, limiting the viability of transport options such as trains.

These basic relationships between income levels and energy use illustrate that total world energy demand will increase as developing countries grow economically. Whether those countries limit per capita energy use to European levels, or emulate the United States, will greatly affect total world energy demand.

### The United States

The United States consumed 98 quads of energy in 2003, approximately 25% of total world demand. Fossil fuels currently supply approximately 86% of United States demand (Figure 2.8) (EIA 2005b). Nuclear's share is 8%; renewables, largely hydroelectric, wood, municipal solid waste,

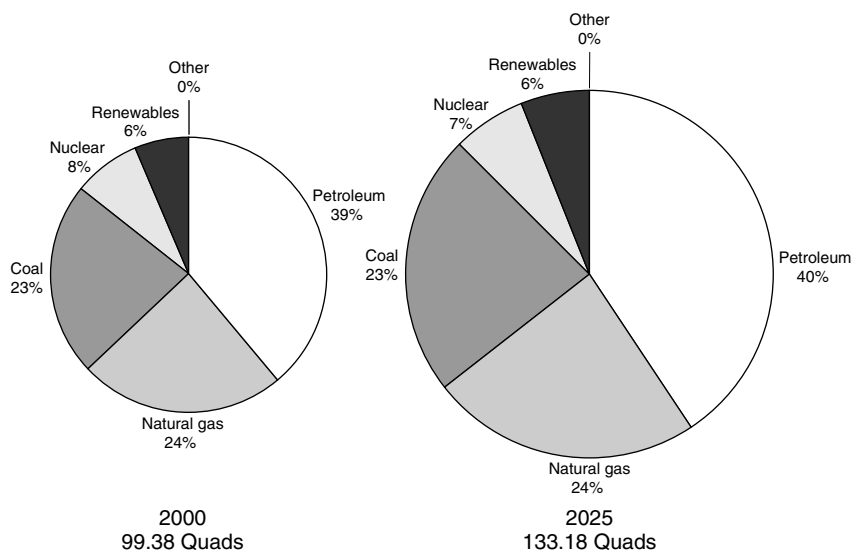


Figure 2.8. United States energy consumption by source, 2000 and 2025. (Source: EIA 2005b.)

and ethanol, supply the remaining 6%.<sup>13</sup> According to the Department of Energy forecasts, the heavy reliance on fossil fuels is not expected to change in the next couple decades, as is the case at the global level. While at the aggregate level there appears just a slight increase in the overall share for natural gas, its importance in the electricity sector is expected to grow considerably, from 13 to 18% (Figure 2.9). Expected decreases in nuclear energy and hydroelectric energy make up for this difference. Meanwhile, non-hydro renewables are expected to capture slightly more of the market (EIA 2005a).

While the DOE and others project increased reliance on natural gas, this future is not pre-ordained, but rather reflects

- present concerns about the environmental consequences of reliance on coal;
- public acceptance of the nuclear option, the ability to build natural gas plants of many sizes and to bring them online quickly (two to 3 years);
- projected unfavorable economics of many of the renewable options (one exception is wind).

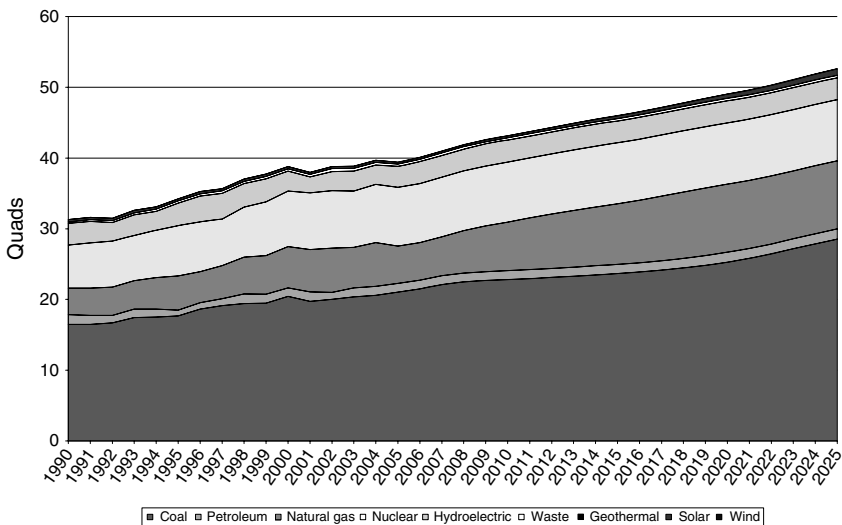


Figure 2.9. Projected fuel shares in US electricity sector, 1990–2025.  
(Source: EIA 2006a; EIA 2005a.)

<sup>13</sup> The renewable share includes: hydroelectric (44.6%), wood, municipal solid waste, and ethanol (46.5%), geothermal (5.5%), wind (2%), and solar (<1%).

This suggests a fundamental reversal of forecasts made in the 1970s, when nuclear was seen as the most likely choice for the future, and when utilities were not allowed to use natural gas to produce electricity due to concerns about availability and its perceived higher value use in the residential sector. But as mentioned earlier, the rapid increase in natural gas prices in the 2004–2005 time frame once again may change conventional wisdom – coal and nuclear have begun to look a lot more attractive to investors.

### *Long-term trends in fuel types*

The fuel required to cook a dinner in Paris costs nearly as much as the dinner itself. Fuel is very scarce, and the American is surprised to find shops all over the city, fitted up with shelves like those shoe stores, upon which is stored wood, split in pieces about the size of a man's finger, done up in bundles, like asparagus. Larger stakes are bottled up in the same way, and sell at a frightful price. Hard coal really being nearly as expensive as wood, can be bought in the smallest quantity in any of these fuel shops.

*Scientific American*, February 1856.<sup>14</sup>

While the Department of Energy and others have forecast an increased reliance on fossil fuels over the next 20 years, looking back over the last couple centuries two overarching trends are apparent: a movement from solids to liquids to gases, and the decreasing carbon intensity of the overall energy mix. Figure 2.10 illustrates these trends in the United States. From the 1600s through the majority of the nineteenth century, wood was the dominant energy source. The market for coal in the United States began to develop in the 1570s, but did not surpass the use of wood until 300 years later, when in 1885 it became the primary energy source. It remained the dominant energy source until World War II when petroleum use surpassed the consumption of coal. While petroleum still remains dominant, natural gas consumption is trending upward at a faster rate than petroleum. While the overall trend appears to be shifting from solids to liquids and now to gases, one also should note that the length of the transitions from one primary energy source to another is measured in centuries – it took over 300 years for coal to surpass wood! This is not meant as an argument against hydrogen but rather a reminder of the inertia in the existing system.

The second long-term trend in energy has been the decarbonization of our fuel sources. The world has moved from energy sources

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<sup>14</sup> Reprinted in *Scientific American* (2006).

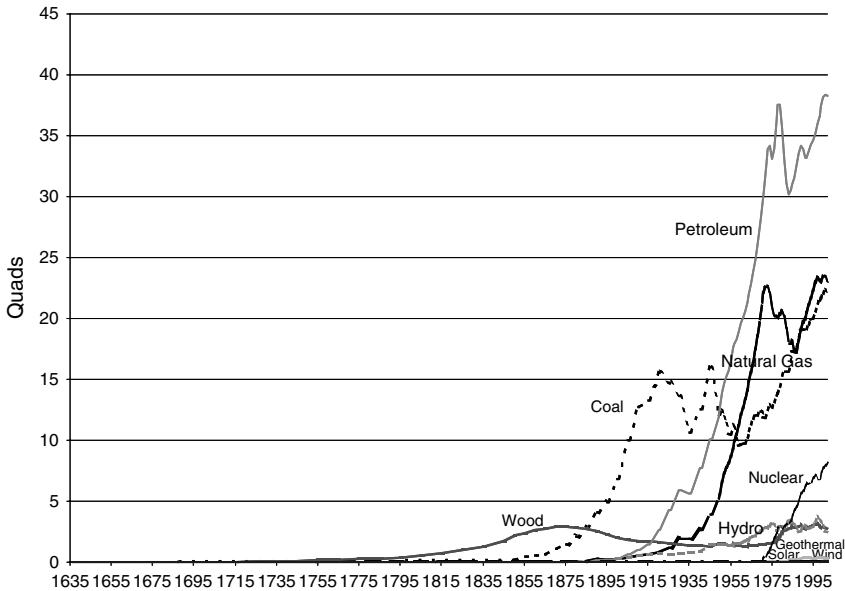


Figure 2.10. United States energy consumption trends, 1635–2002.  
(Source: EIA 2006a.)

with low hydrogen-to-carbon ratios to those with higher ratios. Coal has a hydrogen-to-carbon ratio of 0.5:1 while oil has a ratio of 2:1 and natural gas has a ratio of 4:1. Furthermore, consumption of non-carbon-emitting energy sources has been increasing over the past few decades. Hydroelectric was the first non-carbon-emitting source to enter the market in the last part of the nineteenth century, followed by nuclear, geothermal, solar, and wind power. The transition from natural gas to hydrogen would be the natural next step in this trend. While the world has been moving away from energy sources with lower hydrogen-to-carbon-ratios, we still are reliant primarily on fossil fuels.

The world, however, cannot rely on fossil fuels forever. We eventually will hit resource constraints. As these constraints are reached, prices will begin to increase, making the transition to alternative fuels more attractive. Some, such as Campbell and Laherrère (1998), contend that we are close to hitting that point for oil, arguing that we must begin the transition away from oil. Others are more optimistic about the remaining supplies. These differences of opinion comprise the crux of the energy debate.

## **Adequacy of Reserves**

Barring a global recession, it seems most likely that the world production of conventional oil will peak during the first decade of the twenty-first century.

Colin Campbell and Jean Laherrère, *Petroconsultants*, 1998.

We are not running out of oil any time soon.

Dr Steven Koonin, Chief Scientist, BP, 2005 (Keener 2006).

It took us 125 years to use the first trillion barrels of oil. We'll use the next trillion in 30.

Chevron Ad, 2006.

Worldwide demand for energy is projected to increase 50% by 2025. Despite some advances by nuclear and perhaps wind technologies, fossil fuels are expected to remain the dominant source of energy for the foreseeable future. This is despite warnings from prominent geologists that oil production has already or will soon peak, meaning that oil will become scarcer and prices will continue to climb: "From an economic perspective, when the world runs completely out of oil is thus not directly relevant: what matters is when production begins to taper off. Beyond that point prices will rise unless demand declines commensurately" (Campbell and Laherrère 1998). Other equally prominent geologists seem to discount these concerns. Notes Steve Koonin, Chief Scientist at BP,<sup>15</sup> "If you include enhanced oil recovery, super deep reserves, tar sands, and oil shale you can extend the petroleum use curve. . . . It depends on what you call oil" (Keener 2006).

Two issues are key. Are reserves sufficient to meet our long-term energy needs? Will the distribution of these resources hinder this long-term projected growth?

### *Reserves*

Understanding our long-term energy needs necessitates a review of reserves and estimates of reserves by fuel type. How long these reserves may last may be considered using a simple measure of reserve size, the reserve-to-production (*R:P*) ratio, or a more complex method, the Hubbert Peak analysis. This analysis assumes production from oil fields basically follows a bell curve, where production increases until the maximum production rate is reached when half the resource has been

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<sup>15</sup>Originally known as British Petroleum, BP now stands for Beyond Petroleum (BP 2005).

depleted. Beyond that peak, production wanes, resulting in higher prices as the resource is depleted.

*What are reserves?*

### **Resource Terminology**

*Proved reserves* are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

*Unproved reserves* are based on geologic and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

*Probable reserves* are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

*Possible reserves* are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

*Estimated ultimate recovery (EUR)* is not a resource category as such, but a term which may be applied to an individual accumulation of any status or maturity (discovered or undiscovered). Estimated ultimate recovery is defined as those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced from there.

*Source:* SPE et al. 1997.

Remaining supplies of finite resources, such as fossil fuels, are discussed in terms of reserves and resources. There are several different categories based on geologic certainty and technical and economic feasibility of recovering the resource. Categories range from proven to possible (see Text Box: Resource terminology). Proven reserves<sup>16</sup> are those which “can be estimated with reasonable certainty to be commercially recoverable . . . from known reservoirs and under current economic conditions, operating methods, and government regulations.” Key to this definition are the requirements that the resource is recoverable with existing technology and economics. Most, but not all sources, including the DOE, report proved reserves. Because total reserves depend both on the current price of the energy source and the current technological abilities to extract it, the total reserve size changes relative to these two variables. As technology improves over time, reserves increase. As oil prices fluctuate, reserves either increase or decrease.

Figure 2.11 illustrates McKelvey’s diagram, used by the United States Geologic Survey, to illustrate the relationships between price, technology, geologic certainty, and proved reserve size. The horizontal axis shows the relationship between reserve size and geologic uncertainty, with the less certain quantities toward the right of the rectangle. The vertical axis shows the relationship between extraction costs at current technological levels and reserve size, with the most expensive extraction costs on the bottom of the diagram. Therefore, the reserves are made up of the rectangle bordered by the known quantity, toward the left side of the diagram, and the economically extractable quantity toward the top of the diagram. As oil prices increase or as recovery technology

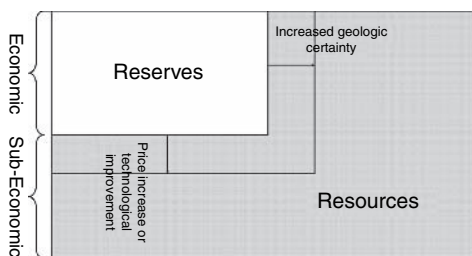


Figure 2.11. McKelvey diagram defining resources and reserves.

<sup>16</sup> Note: This term is equivalent to “Demonstrated Reserves” as defined in the resource/reserve classification contained in the United States Geological Survey, Circular 831, 1980. Demonstrated reserves include measured and indicated reserves but exclude inferred reserves.

improves, reserves increase. If exploration reduces uncertainty about a certain field, reserves increase. The flip side of this is that if prices decrease, reserves actually shrink, not because the resource is depleted, but because the resources are no longer economically recoverable at existing market prices.

Many sources, including the DOE, further categorize reserves, differentiating between proven reserves, indicated reserves, and inferred reserves. Each succeeding level indicates less certainty. Indicated reserves are what are deemed recoverable from known fields using improved recovery techniques. Inferred reserves are reserves thought to exist in identified fields but that have not been measured (Hinrichs 2002).

Still others discuss reserves in terms of possible and probable reserves. Possible reserves have less than a 50% chance of existing, while probable reserves have over a 50% chance of existing. Unfortunately, different countries and organizations use different probabilities to report reserves. For example, the United States measures reserve size using a P90 estimate, meaning there is at least a 90% probability that the quantity exists in the field. However, not all countries, or experts, use the P90 criteria. In the United States, the Security and Exchange Commission (SEC) requires publicly traded companies to utilize the P90 estimates (see Text Box: Royal Dutch/Shell reserve categorization). As noted by Campbell and Laherrère (1998), by using a P90 estimate for all fields likely will underestimate total reserve size, while P10 estimates, which suggest only a 10% chance that the quantity exists, will overestimate. Using a P50 estimate across the board, they continue, would produce the most accurate assessment of total reserve size, because the errors that occur in estimations of each individual field would cancel out each other.

A final term used to define total oil reserves is estimated ultimately recoverable (EUR) reserves, which includes cumulative production to date, current reserve estimates, and those reserves that remain to be found and exploited. In Figure 2.11, the EUR would make up a portion of the resource base plus cumulative production to date.

Estimating total remaining reserves is not an easy task, and as one would expect, there are many estimates and considerable controversy about the amount of remaining resources.

## **Reserve Estimates**

How long will remaining reserves of fossil fuels last? For coal, the answer is measured in centuries, while for oil and natural gas the answer is measured in decades. How many decades is the subject of considerable debate, especially for oil. This debate is referred to as the “peak oil” argument.

**Royal Dutch/Shell reserve recategorization**

In January 2004 Royal Dutch/Shell, the world's third-largest publicly traded oil company, announced a recategorization of 3.9 billion barrels of oil equivalent, citing less certainty than is required by the United States Securities and Exchange Commission (SEC) to be considered proven reserves. One example of these recategorizations is an Australian project in which Shell classified a field as proven while other companies involved did not classify it as positively.

The sudden recategorization prompted an SEC investigation into the company's actions which is still under way, an independent review of Shell's reserves, and an internal review of the management. The independent review of reserves resulted in the further recategorization of the Ormen Lange field in Norway, where seismic technology was used to determine the reserve size. But there was no other form of verification, an SEC requirement. By April, when 90% of reserves had been reviewed, the recategorization total was 4.35 billion barrels of oil equivalent, or 22% of its proved reserves. Approximately 70% of these reductions were related to oil and natural gas liquids, while the remaining reductions were related to natural gas. The recategorization of reserves resulted in a reserve replacement ratio decrease for Shell of approximately 60% and a reserve life of 10.2 years at the end of 2003.

The Shell Group Audit Committee, responsible for the internal review of the management, commissioned Davis Polk & Wardwell to conduct an independent investigation into issues surrounding the recategorization. While Shell executives originally claimed that they released the information to the public as soon as possible, the investigation uncovered numerous documents exchanged between high-ranking company executives, including Sir Phillip Watts, Chairman of the company, and Walter van de Vijver, head of exploration and production. The documents suggested that they were aware of these shortfalls years earlier. "Rather than disclose the problems to investors, senior executives in a July 2002 memorandum came up with - and later carried out - what the memorandum described as an 'external storyline' and 'investor relations script' that tried to 'highlight major projects fueling growth,' 'stress the strength' of existing resources, and minimize the significance of reserves as a measure of growth" (Labaton and Gerth 2004). The investigation has resulted in the resignations of both Watts and van de Vijver.

*Source:* Davis Polk & Wardwell 2004; Fuerbringer 2004; Labaton and Gerth 2004; Royal Dutch/Shell 2004a,b; Timmons 2004.

## Oil

In a controversial *Scientific American* article published in 1998, “The End of Cheap Oil,” geologists Campbell and Laherrère (1998) argue that global oil production will peak in the first decade of the twenty-first century, leading to rapidly increasing prices. Campbell and Laherrère suggest there is little that can be done to delay the inevitable, noting that even if their estimates are a few hundred billion barrels low, the peak shifts by only a few years. Others reject this claim, noting that technological advances in drilling and exploration and the existence of huge reserves of unconventional oil, including the “tar sands” of Canada, mean supplies will last significantly longer. Red Cavaney (2006), president and CEO of the American Petroleum Institute notes, “Once again we are hearing that world oil production is peaking, and that we will face a steadily diminishing oil supply to fuel the global economy. These concerns have been expressed periodically over the years, but have always been at odds with energy and economic realities. Such is the case today.”

How can oil experts be in such disagreement? As mentioned previously, part of the uncertainty regarding remaining reserve size is the lack of clear criteria for categorizing reserves as proven. While the United States requires a P90 estimate, others may use P50 or even P10 estimates. Both Campbell and Laherrère (1998) and Deffeyes (2001) note that reserve estimates also can be influenced by politics. As an example, they cite reserve estimates in several Middle Eastern countries during the 1980s which increased by 42–197% almost overnight. The increased reserve estimates were not because vast new fields were discovered, but rather because OPEC was designing a production quota system. Under this system, one criterion used to determine a country’s allowed output was its estimated reserves.<sup>17</sup>

Table 2.2 summarizes oil reserve estimates from several sources. The estimates range from Campbell and Laherrère’s estimate of 1 trillion barrels to the US Geologic Survey’s estimate of 2.2 trillion barrels (Wood and Long 2000). For comparison, cumulative production to date is approximately 0.8 trillion barrels.

As economist M. A. Adelman contends, “Oil reserves are not a fixed stock to be allocated over time, but an inventory, constantly consumed

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<sup>17</sup> “In the late 1980s there were huge and abrupt increases in the announced oil reserves for several OPEC nations . . . Earlier, each OPEC nation was assigned a share of the oil market based on the country’s annual production capacity. OPEC changed the rule in the 1980s to consider also the oil reserves of each country. Most countries promptly increased their reserve estimates.” (Deffeyes 2001)

Table 2.2. Remaining reserve estimates.

	Remaining reserves (billion barrels)
USGS	2203
Campbell and Lahererre	1000
Oil & Gas Journal	1213
World Oil	1035
British Petroleum	1148

Sources: BP (2004), Campbell and Lahererre (1998), EIA (2005b), USGS (2000).

and replenished by investment” (Greene 1997). Adelman and others do not disagree that oil is a finite resource; rather, they acknowledge that oil reserves constantly are increasing while also being depleted, and should therefore be seen as a flow rather than a fixed resource. Much of this idea is based on the rejection of Hotelling’s theory of exhaustible resources, which argues that the cost of oil would increase if it were in fact a finite resource, as each barrel would become more expensive than the last to extract. However, as previously mentioned, prices historically have remained fairly low (Emerson 1997). Some, including many geologists, contend that oil is an inherently finite resource and while reserves, determined in part by economics, might change, the total availability of oil is limited. Oil prices, they counter, will begin climbing once production begins to decline. Campbell and Laherrère (1998) argue that we will reach that point within a decade. Furthermore, they doubt the existence of large quantities of undiscovered oil or that technology and financial resources will lead to significant increases in drilling and extraction abilities.

#### *Adequacy of existing reserves*

Two methods commonly are used to assess the adequacy of existing reserves: the reserve-to-production ratio and the calculation of the timing of peak production from existing fields, or Hubbert’s Peak methodology. The simplest is the *R:P* method. *R:P* ratios for oil reserves are summarized in Table 2.3. At first glance, they suggest oil reserves will last approximately 40 years at current production rates. Of course, as world demand soars, production also will increase, lowering the *R:P* ratio.

Reserve-to-production ratios are highly misleading as they assume steady production, but no one expects production to remain at current levels. The DOE estimate suggests oil production will increase by over 50% from current levels by 2025. At the same time, reserve sizes are, by definition, not fixed. They will increase as prices increase, technology

Table 2.3. Global oil reserve-to-production ratios.

	<i>R:P</i>
USGS	78
Campbell and Lahererre	35
Oil & Gas Journal	43
World Oil	37
British Petroleum	41

*Sources:* BP (2004), Campbell and Lahererre (1998), EIA (2005b), USGS (2000).

allows for higher levels of extraction from existing fields, or as new fields are discovered. However, a decrease in the price of oil would result in a decrease in reserve size.

As is often noted by critics of “peak oil” theory, reserve-to-production ratios have, with the exception of a few years, steadily increased throughout the last couple decades, as discoveries have outweighed production (Figure 2.12). Specifically, the global *R:P* increased almost every year through approximately 1990, especially during the period from 1987 to 1990 when members of OPEC were inflating reserves to

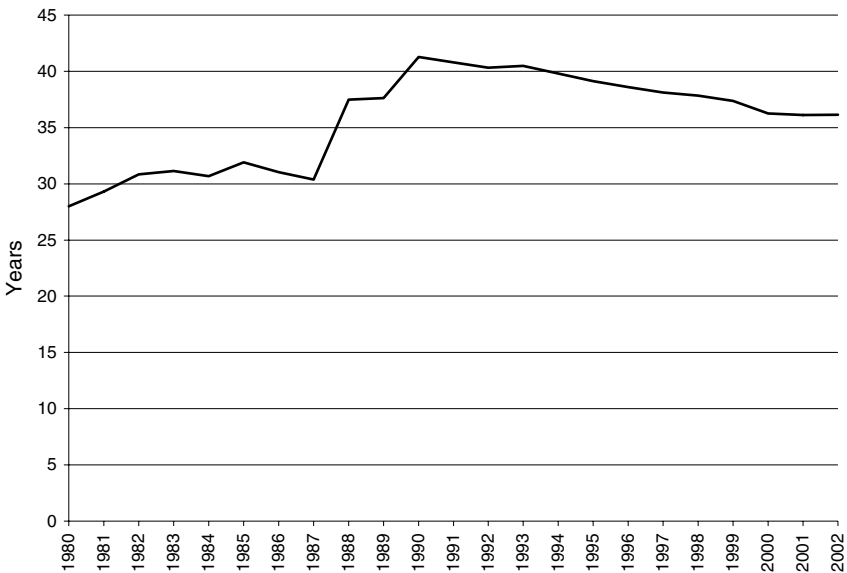


Figure 2.12. World oil reserve-to-production ratio, 1980-2002.

(Source: EIA 2005b, 2006d.)

increase their quotas. Since 1990 there has been a gradual downward trend in the  $R:P$ , illustrating that production has increased relative to reserve increases. Even so, the  $R:P$  suggests that at current production levels the world's reserves will last upward of 35 years and as much as 78 years, depending on the source of reserve estimates (Table 2.3).

However, as production increases, the reserve-to-production ratio will decrease if the production is not countered by increased reserves. Campbell and Laherrère (1998) caution that this increase exists only because countries have been reporting growing reserves while failing to report resource depletion. And even a Chevron ad says, "The world consumes two barrels of oil for every barrel discovered" (Alekklett 2006). Rather than increasing, Campbell and Laherrère argue that  $R:P$  actually has been decreasing because for every barrel of oil found, three are consumed.

The  $R:P$  ratio gives a rough indication of how long reserves will last at a given production rate. A second, more detailed method for estimating remaining years of production is Hubbert's Peak analysis, named after geologist M. King Hubbert. In 1956, Hubbert predicted that United States oil production would peak in the early 1970s. Most people in the industry initially rejected his analysis. However, Hubbert was right – United States oil production peaked exactly as predicted (Figure 2.13).



Figure 2.13. Oil production in the lower 48 states of the United States.

Source: EIA 2006a.

In *The Hydrogen Economy*, Jeremy Rifkin summarizes the theory used to derive these predictions.

Hubbert's thesis is elegant in its simplicity. He argued that oil production starts at zero, rises, peaks when half the estimated ultimately recoverable oil is produced, and then falls, all along a classic bell-shaped curve. The extraction of oil begins slowly and then begins to accelerate quickly as big oil fields are located. After the biggest fields are found and exploited, production begins to slow. The smaller fields become harder to find and the oil more expensive to drill and produce. At the same time, as the larger fields are drained, the remaining oil becomes more difficult to pump to the surface. The gush gives way to a slow, steady, declining flow. The combination of the declining rate of discovery and the decline in production in existing fields eventually results in a production peak. The top of the bell curve represents the midpoint, at which half of the ultimately recoverable reserves have been produced. From that point on, production drops as fast as it has climbed, along the second half of the bell curve

(Rifkin 2002).

Figure 2.13 illustrates the pattern of oil production in the United States from 1954 to 2003. The bell-shaped curve shows peak production occurring in the early 1970s, as initially predicted by Hubbert.

Several experts have applied the Hubbert methodology to global oil production. Deffeyes (2001) estimated that global oil production would peak in approximately 2003 and total eventual recovery would number 2.12 trillion barrels of oil. Likewise, Campbell and Laherrère (1998), using Hubbert's first method and their low estimate of 1.8 trillion barrels of EUR, estimated a production peak in 2003. Their analysis showed that the total reserve size had little effect on the production peak year and that a higher estimate of 2.1 trillion barrels (P05) results in a peak in 2020.

What's interesting, however, is that the two methods for evaluating remaining supplies, *R:P* and Hubbert's Peak, are not contradictory. They simply pose two analytical viewpoints. Campbell and Laherrère's (1998) analysis using Hubbert's curve shows global production decreasing essentially to zero in approximately 40 years, the same as the *R:P* used to predict when the supply of oil will run out. The discrepancy in this analysis, however, is that the *R:P* assumes constant levels of production while the bell curve assumes decreasing levels of production after the peak.

The debate over "peak oil" comes down to four main issues: the ability of technology to increase the amount of oil extracted from existing fields, the effect of economics on reserve size, the possibility of using unconventional oil, and the likelihood of discovering large new oil fields.

*Role of technology in increasing recoverable oil*

Reserve estimates increase as technological advancements make it possible to increase the amount of recoverable oil. Critics of the “peak oil” argument continually cite technological advancements in recent years that have resulted in increased ability to not only find new fields, but also to extract more oil from each. Such technologies include computer-generated seismic imaging, which increases the knowledge of each well drilled. This results in more efficient means of finding new sources of oil as well as enhanced underwater recovery techniques (Emerson 1997). Whereas only about 30% of oil could be extracted from each well using the available technologies in the 1960s, new technologies have made it possible to extract an average of 40–50% from each well. These technology optimists believe that future technology may further increase that estimate. Not so, argue Campbell and Laherrère. They counter that many reserve estimates already build in technological advances and that increased spending on research and development is unlikely to dramatically improve extraction rates.

While petroleum engineers have found ways to increase the percentage of oil recoverable from existing fields, evidence from the oil fields in Iraq suggest that there is a delicate balance between enhanced oil recovery techniques and field damage. Assessments of several large Iraqi oilfields following the United States-led invasion of 2003 suggest that the fields ultimately may have recoveries of only 15–25%, since they were mismanaged in efforts to meet the high production demands set by Saddam Hussein (Gerth 2003). Such damage is possible if proper pressure levels were not maintained and water and other gases were allowed to seep back into the wells, making pumping more difficult and more expensive.

*Effect of economics on reserve size*

Economics affects estimated oil reserves in two ways. Higher oil prices lead to increased drilling and exploration, which can lead to new fields; and more “resources” become economically viable with existing technology. When oil prices increased in the late 1970s and early 1980s, reserve size also increased. In the United States, improved technology made new reserves in Oklahoma and Texas economical. While the technology had existed for some time, not until there was a concern about an oil shortage and price increases was it used and proved very successful (Mann 2002). Cavaney suggests there are more than 131 billion barrels of oil and over 1000 trillion ft<sup>3</sup> of gas waiting to be discovered within the United States (Cavaney 2006). The vast majority of this is either under federal lands or in coastal waters. To counter this claim,

Aleklett (2006), the president of the Association for the Study of Peak Oil and Gas, notes, "Fifty years ago the world was consuming 4 billion barrels of oil per year and the average discovery rate was around 30 billion barrels per year. Today we consume 30 billion barrels per year and the discovery rate is dropping toward 4 billion barrels per year." Furthermore, he notes that the last major discovery was at the North Sea in 1969, a reserve estimated at about 60 billion barrels. That same field peaked in 1999 with a production rate of 6 million barrels per day. Another nationally recognized oil expert, Robert Kaufmann, notes that while there are more than 14 000 oil fields in the United States alone, 40% of the total supply comes from just the largest 100. "Once these larger fields are depleted they are replaced with fields that are 1/10 or even 1/100 their size" (Kaufmann 2006). Finally, Deffeyes (2001) argues against the common notion that increased prices will lead to substantial new discoveries. He points out that more oil was discovered in the United States during the 1930s, the time of the Great Depression when oil was \$1 per barrel, than in any other decade in United States history, thus illustrating the minimal impact that economics had on the discovery of oil.

### *Unconventional oil*

Optimists argue that there are vast quantities of unconventional oil that can some day be trapped. These unconventional sources include tar sands (or oil sands), oil shale, and other liquid fuels created from coal, or biomass. There are estimates as high as 40 000 billion barrels available in unconventional oil reserves (Odell 1999). Bartlett (2002) notes there is a long history of assuming that approximately 40 \$/bbl is the magic number at which such sources become competitive. While there is considerable evidence to support this claim, investors will be wary of large investments in an industry where high oil prices are often followed in short order by very low prices. Perhaps more importantly, getting at these resources poses significant environmental challenges.

As oil prices increased in the 2004–2005 time frame, interest in unconventional sources has grown. These include a major oil sands project in Alberta, Canada; ethanol projects in the United States, Europe, and Brazil; and even natural gas to liquid (GTL) projects in Qatar, and coal to liquid (CTL) projects in South Africa, China, and the United States. None of these options is actually captured in the "oil reserve" estimates. This illustrates how economics and technology can lead to increased, or even unforeseen, options.

## Oil Sands

Estimates suggest there could be as many as 1.7 trillion barrels of oil trapped in the ground in Alberta (Woynillowicz et al. 2005), more than the total oil reserve estimates discussed earlier. However, current estimates suggest that out of this, only 315 billion barrels ultimately may be recoverable, and only 174 billion barrels can be classified as “reserves” based on existing technology and economics. Nevertheless, this is a very large reserve. Including the oil sand reserves, Canada is second only to Saudi Arabia in reserves.<sup>18</sup>

Attempts to extract oil from the Canadian oil sands date all the way back to 1944. In recent years, interest has surged, as technology has improved and as tax breaks and incentives have made the site a good investment. By 2004, four of the five largest publicly traded oil companies had invested in Alberta oil sands, as had Chinese oil companies. Whereas early projections suggested production could reach 1.2 mbd by 2020, this goal was reached in 2004. One projection suggests Canadian production could surpass 3.5 mbd by 2008 (E&E Daily 2006).

Producing oil from these reserves will have significant and negative environmental consequences. The production of one barrel of oil requires mining and processing four metric tons of material.<sup>19</sup> The oil sands are approximately 10–12% bitumen by weight and exhibit a strong hydrocarbon smell. Both strip mining for shallow deposits and in situ methods for deeper deposits are used to process the oil sands. Once the material is dug up, the bitumen is coaxed from the rest, resulting in a thick oil that does not flow freely. The separation process requires both fresh water (two to five barrels of fresh water per barrel of oil) and heat (250 ft<sup>3</sup> of natural gas per barrel). The thick bitumen is then further upgraded by adding hydrogen (hydrocracking), which results in a lighter, higher quality synthetic crude. This synthetic crude is then subjected to high pressures and temperatures (hydrotreating) to remove the nitrogen and sulfur. An additional 500 ft<sup>3</sup> of natural gas per barrel is used in this latter stage. Because the process requires so much natural gas, there is interest in locating high-temperature nuclear reactors onsite. And of course, many of these projects, if not all, could become uneconomical if oil prices once again plummeted, as they have so many times in the past.

The Pembina Institute (Woynillowicz et al. 2005) estimates that the production costs have fallen to around \$13 Canadian per barrel, but this

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<sup>18</sup> The December 2004 Oil & Gas Journal estimates Canada’s oil reserves, including the oil sands, at 179 billion barrels. Saudi Arabia’s reserves are estimated at 259 billion barrels.

<sup>19</sup> The description of the basic process is adapted from Pembina Institute, 2005.

number also is widely dependent on natural gas prices. The Pembina Institute's report on the oil sands puts the whole process in perspective by noting "One barrel of synthetic crude produces enough gasoline to fill three-quarters of a Chevy Avalanche's gas tank, or enough to drive it about 490 kilometers."

Campbell and Laherrère concede that there are vast quantities of unconventional oil available worldwide. In addition to the oil sands in Canada, they mention Venezuela's Orinoco oil belt, which may contain as many as 1.2 trillion barrels of heavy oil. The rapid development of unconventional oil sites they note is not environmentally acceptable. The Orinoco sludge contains both heavy metals and sulfur that must first be removed. Nevertheless, Campbell and Laherrère do estimate as many as 700 billion barrels could be produced worldwide from unconventional resources over the next 60 years.

### **Coal to Liquid**

Following the oil price spikes of the 1970s, President Carter authorized the creation of the United States Synfuels Corporation. The goal was to turn coal into a liquid fuel. Originally funded at \$20 billion, its budget was slashed in 1984 and eventually killed outright by Congress as oil prices dropped and turning coal into fuel no longer made economic sense. But as oil prices have rebounded in recent years, coal to liquid projects have popped up around the world and now appear to be a real option for countries with abundant coal reserves. The basic process involves subjecting coal to high-temperature steam and pressure. With current technology, 1 ton of coal can produce about 2.6 barrels of a very low sulfur diesel.

South Africa turned to CTL during its apartheid period as a way of surviving trade embargoes. CTL now supplies about 30% of South Africa's domestic demand. The South African Oil Company (SASOL) claims its synthetic fuel is economically competitive at oil prices above 30 \$/bbl. SASOL is helping China plan and build two 50 000 barrels-per-day pilot facilities located near coal mines. China is an obvious place for many more of these facilities to be built. China has significant coal reserves; the fuel can be manufactured right near the coal mines; and the sulfur content of the fuel is as low as 5 parts per million, compared to diesel products now available with diesel contents of 2000 ppm.

There is also a renewed interest in CTL projects in the United States. Currently, there is a 5000 barrel-per-day pilot project in Pennsylvania that will use mining leftovers to produce a synthetic diesel product (Kelderman 2005). A similar initiative is underway in Laurence County,

Ohio. Backers of this project believe the project will help revitalize the county's tax base and create much needed jobs.

### **Gas to Liquid**

GTL technologies have the potential to add significant quantities of new, high-quality liquid fuels to the global fuels market. As with CTL projects, natural gas is converted to a clear liquid fuel using the Fischer-Tropsch process. GTL technologies offer several countries with very large reserves of natural gas and little domestic demand an appealing option to get their product to market. A prime example is Qatar, a country with very large proven reserves of natural gas, but, at present, limited options for selling. That is about to change. Qatar's energy minister states, "It is time to take the genie out of the bottle. . . . we want to be the capital of the world for this new age of fuels" (Romero 2006).

Qatar is now aggressively building capacity to use its stranded natural gas reserves to produce a very high-quality diesel product. Two of the largest projects are with Shell and Exxon Mobil. The Shell project, under construction in 2006, is a \$6 billion seaside project on a site approximately 1.4 by 1.6 km. Approximately 60 000 construction workers are involved – in a country with a population of just 800 000. Exxon Mobil's plant is even larger, and will produce about 154 000 barrels per day. It also represents Exxon Mobil's largest single project investment to date (Romero 2006).

Other GTL plants are under construction or in the planning stages in different parts of the world. Chevron is constructing a \$3 billion plant in Nigeria. Other plants are being considered in Indonesia, Papua New Guinea, Australia, Iran, Egypt, and Trinidad and Tobago. While Romero suggests GTL is economically viable for oil prices above \$30 per barrel, the economics improve if there is no other ready market for the natural gas. One Shell official suggests GTL technology is economically viable at oil prices of \$20 per barrel, as long as natural gas production costs are less than 1 \$/MBtu, as is the case with the Qatar field (Anonymous 2006).

The synthetic crude product is inherently cleaner than its oil-based diesel competitor, which often is high in sulfur. Shell plans to market this cleaner fuel as a means of reducing smog in the world's 27 largest cities (megacities) and the Southern California Air District.

### **Biomass to Liquid**

Biomass to liquid (BTL) refers mainly to projects that utilize crops – such as corn or sugar beets – to produce ethanol, which can be blended with gasoline or burned in modified engines. Ethanol projects are exploding

in number worldwide, due both to increasing oil prices and government efforts to reduce the use of imported oil and support domestic growers. The United States, for example, has set a target of 7.5 billion gallons per year by 2012,<sup>20</sup> approximately 5% of United States fuel demand.<sup>21</sup> The European Union is targeting 5.7% by 2010. But by far the largest producer worldwide is Brazil, which currently produces about 15.7 million liters per year for a cost of 20–30 cents/liter from sugar cane.

Brazil has a long, and often uncertain, history of producing ethanol from sugar cane. Brazil's program began in the 1970s, following the Arab oil embargo and surge in oil prices, as a means to wean itself from reliance on foreign oil. The program was jump-started by strong government incentives for ethanol production, and price supports for ethanol, which made ethanol 35% cheaper than gasoline. With cheap oil prices following 1986 and the end of the price supports in 1989, ethanol's popularity plummeted. Only with the price hikes of this century has interest in ethanol in Brazil once again increased. Widescale marketing of "flexfuel" vehicles, which can run on either gasoline or ethanol, has boosted their popularity in Brazil. Ethanol producers also have become more efficient over the decades. Whereas in 1975 ethanol producers could produce about 200 gallons for each acre of sugar cane, by 2006 the yield increased threefold, to over 600 gallons per acre (Luhnnow and Samor 2006). Sugar cane-derived ethanol now accounts for about 40% of all transportation fuel in Brazil (World Watch Institute 2006).

In the United States, the main source for ethanol is corn. The process for producing ethanol from corn is relatively straightforward. The corn is ground and separated into component sugars, which then are distilled into a clear alcohol. Ethanol has a long history in the United States. In the 1850s it was used to illuminate lamps. The early Model T was a flexible fuel vehicle, capable of running on either gasoline or ethanol. While ethanol soon lost out to gasoline as the fuel of choice for transportation, pockets of use remained until the end of World War II. Interest in ethanol re-emerged in the 1970s with the phaseout of lead and the search for an alternative octane booster. Ethanol's production grew substantially with the passage of the Energy Tax Act of 1978, which officially defined Gasohol as a blend of gasoline and 10% alcohol, but which specifically excluded alcohols made from petroleum, natural gas, or coal. The act

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<sup>20</sup> EPACT, 2005.

<sup>21</sup> Actual goal is 7.5 billion gallons of ethanol by 2012. While this is often expressed as about 5% of US gasoline demand in 2012, this calculation fails to consider that the energy content of a gallon of ethanol (3.082 MBtu/barrel) is significantly lower than a gallon of gasoline (5.253 MBtu/barrel), a factor often ignored in calculation of ethanol's economics as well.

also created a controversial subsidy for ethanol production, amounting to a 40 cents per gallon subsidy for every gallon of ethanol blended into gasoline (EIA 2006b). This subsidy reached 60 cents per gallon in 1983. A 1998 law reduced the subsidy to 51 cents per gallon in 2005.

In addition to subsidies, ethanol's popularity has increased for two other reasons. The first is ethanol's use as an oxygenate to lower carbon monoxide emissions, especially in EPA non-attainment zones. Ethanol widely replaced methyl tertiary-butyl ether (MTBE) as the oxygenate of choice in the United States after the discovery that MTBE, a known carcinogen, had leaked into drinking water sources. The second reason for ethanol's popularity is political. Politicians from both major parties in the United States talk about taking the "Iowa pledge." In a state where corn is the major crop, no politician can expect to win the crucial Iowa presidential caucuses without making the pledge to support ethanol.

But while ethanol is expected to capture 5% of the United States liquid fuels market by 2012, larger increases are not practical for several reasons. First, while ethanol is considered a renewable resource, considerable fossil fuels are used in its production. For each unit of ethanol produced, it takes 0.6–0.8 units of energy. This includes the energy required to grow and harvest the corn, the petroleum for fertilizer and pesticides, and the processing costs. This translates into an input-to-output energy ratio of 1: 1.3–1.8. The situation is vastly different in Brazil, with a self reported ratio of 1:8.3, due to the greatly increased yield of sugar beet crops compared to corn. There also are concerns about land use for corn production. One estimate suggests meeting the United States target will require 25% of the entire United States corn crop and 10% of available cropland. Increased corn production may result in sharply increased prices for other agricultural crops if less acreage is available due to increased corn acreage.

And despite the targets for increased use of ethanol worldwide, the overall impact is still quite small. The IEA estimates that ethanol supply will only amount to some 2 million barrels per day in 2025, a small fraction of the likely global demand for oil (119 mbd).

### Undiscovered Reserves

Are there still undiscovered oil fields? Absolutely. The real question, though, is whether any *major* fields have gone undiscovered. New fields will lead to increased reserves. Odell (1999) argues that both new technologies and the discovery of new fields have resulted in increasing reserve size for decades, more than enough to outweigh production. Others point out there are many areas, such as off-shore regions, that

have not been fully developed and which also could increase drastically total reserves. Additionally, new reserves could exist underneath already discovered reserves, increasing the size of some fields. And Thomas Gold, an astronomer at Cornell University, disagrees with the common notion that oil reserves result from the decomposition of organic material. Instead, he suggests, "Oil and gas are in fact the remains of methane left over from the earth's origin" (Bartlett 2002). If Gold is correct, oil and gas would exist not only at the Earth's surface, but also within the core, increasing the potential for additional fossil fuel reserves.

Campbell and Laherrère discount the possibility of large new fields, and estimate the oil industry already has found 90% of existing oil. They note that "about 80% of the oil produced today flows from fields that were found before 1973, and the great majority of them are declining" (Campbell and Laherrère 1998). Some experts further argue that "no major oil provinces (those producing 7 billion to 25 billion barrels) have been found since 1980" (Ivanhoe 1997).

### *Natural gas*

Estimates of natural gas reserves range from 4793 trillion ft<sup>3</sup> (USGS 2000) to 6204 trillion ft<sup>3</sup> (BP 2004). Over the past three decades, global natural gas reserves have been consistently increasing (Figure 2.14), meaning that discoveries have outweighed consumption. Some of the more drastic increases were a function of discoveries in previously unexplored countries, especially developing countries.

In a mature energy system such as the United States, production followed the expected exponential growth in early years and then began to taper off in the early 1970s. However, in the past three decades production of natural gas has been trending upward (EIA 2006a). Figure 2.15 illustrates the trend in *R:P* ratios since 1980 for natural gas. In recent years, natural gas reserve increases have been outpaced by production increases. Natural gas consumption in the electricity sector has been on the rise in recent years due largely to environmental issues.

While total reserves have increased since the 1970s, the *R:P* has remained fairly stable (Figure 2.15), illustrative of the increased consumption of natural gas worldwide. The fairly constant *R:P* indicates that these increases in reserves have been matched by increases in consumption.

In its most recent assessment of natural gas markets, the National Petroleum Council (2003) suggests there has been a fundamental shift in the natural gas supply and demand balance as power generators and industrial customers have become more dependent on gas-fired

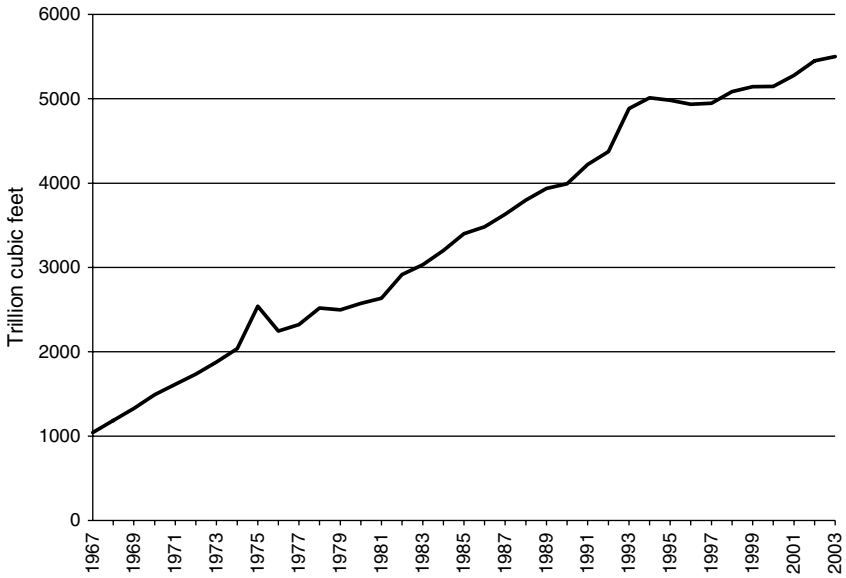


Figure 2.14. Global natural gas reserve estimates, 1967-2003.

Source: Oil & Gas Journal 2003.

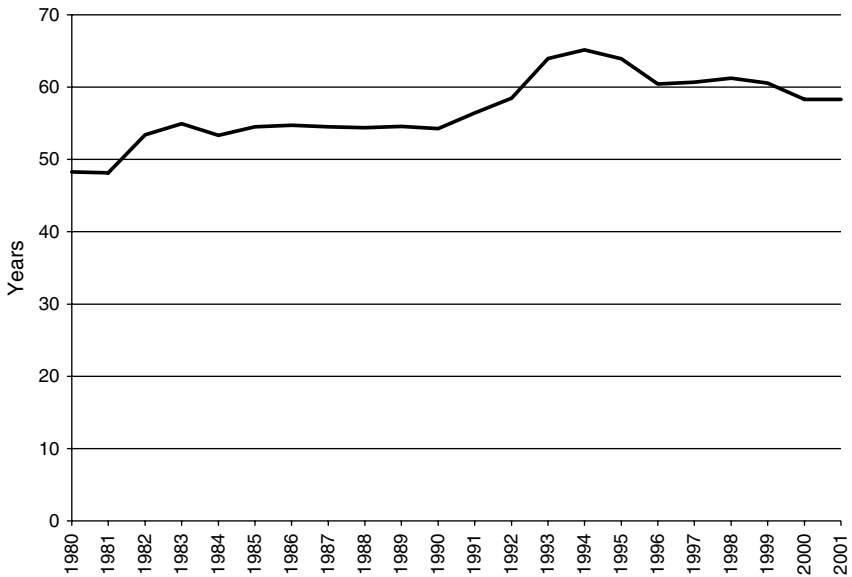


Figure 2.15. Global natural gas reserve-to-production ratio, 1980-2001.

Sources: Oil & Gas Journal 2003; EIA 2005b.

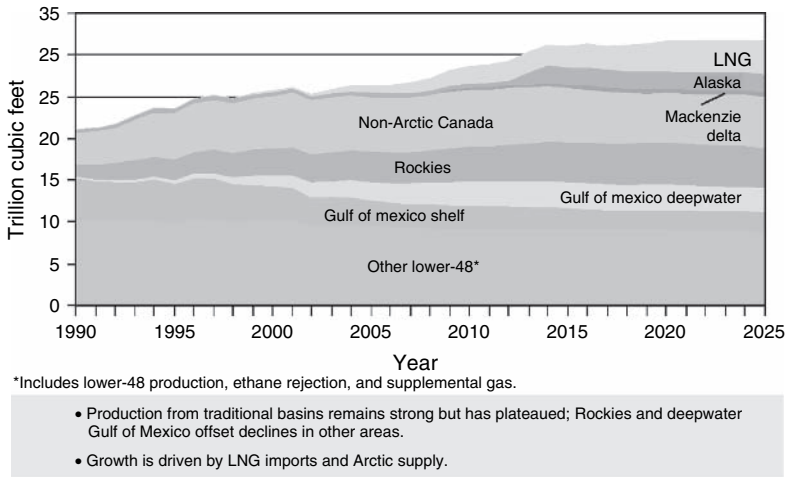


Figure 2.16. National Petroleum Council long-term natural gas supply forecasts.  
Source: NPC 2003

equipment. The council's detailed analysis of likely supply options concludes that domestic sources "will be unable to meet projected demand" (NPC 2003). Meeting the growing demand, the council suggests, will require significant increases in imported liquefied natural gas (LNG) (Figure 2.16).

### Coal

There is little debate over reserve estimates and the potential for growth in reserves of coal. Reserve estimates for coal are divided into two categories: (1) anthracite and bituminous; (2) lignite and subbituminous. The Energy Information Administration reports total world recoverable coal reserves of approximately 1081 billion short tons, with slightly over half being anthracite and bituminous (EIA 2005b). In terms of the heat content of the fuels, the energy content of recoverable coal is more than three times that of either oil or natural gas reserves.<sup>22</sup>

Furthermore, while the consumption of oil and natural gas has increased in recent decades (Figure 2.2), global coal production has remained fairly constant since 1990. With production levels hovering around 5000 million short tons of coal per year and with reserves of

<sup>22</sup> Found using US heat content from EIA of 1026 Btu/ft<sup>3</sup>, 5 800 000 Btu/bbl, and 20 905 000 Btu/short ton coal and oil and gas journal reserve estimates for oil and natural gas.

approximately 1 trillion short tons (EIA 2005b), the current reserve-to-production ratio results in just over a 200-year supply, considerably longer than the supply resulting from the estimated *R:P* ratios for oil and natural gas. However, because coal has been a primary source of energy for countries for over a century, patterns seen with its reserve size and production rate can illustrate the accuracy of Hubbert's bell-shaped curve theory.

In his book, *Hubbert's Peak: The Impending World Oil Shortage*, Deffeyes (2001) argues that the production of anthracite coal in Pennsylvania followed the Hubbert curve. Coal production in Pennsylvania commenced in 1830 and grew exponentially until production peaked in 1920 when half of the recoverable reserves had been extracted. Production then declined, with the exception of a spike in production during World War II. By 1980 production was nearing zero.

Deffeyes (2001) argues that this illustrates the ways in which the coal industry, which has existed for a significantly longer period of time than other energy industries, supports Hubbert's hypothesis that production follows a bell-shaped curve with a peak when approximately half the reserves have been depleted.

While some argue that fossil fuel reserves historically have been increasing due to new technology and economics, others believe little room remains for technological advancement and discovery, leading to an impending shortage of resources, especially oil. Furthermore, while some analyze reserve size in terms of the reserve-to-production ratio, others choose to use Hubbert's theory relating to peak production year and the timing of price increases as production declines.

### **Reserve Distribution**

Almost as important as reserve size is reserve distribution. While current reserve estimates and production levels indicate global supplies of oil, natural gas, and coal, of 40, 60, and 200 years, respectively, these supplies are not universally distributed across the world.

Distribution of crude oil reserves does not favor the industrialized world. Only 5% of identified reserves are located in OECD countries (Figure 2.17). While the United States consumes approximately 25% of the world's oil, its oil reserves are less than 3% of global reserves (BP 2004). China, with its huge population and soaring consumption, likewise has just 2% of global reserves. More than three-fourths of estimated reserves are located in OPEC member countries, giving them considerable power in the global oil market. Russia also holds 6% of the world oil and could become a large player in the market in future years. The

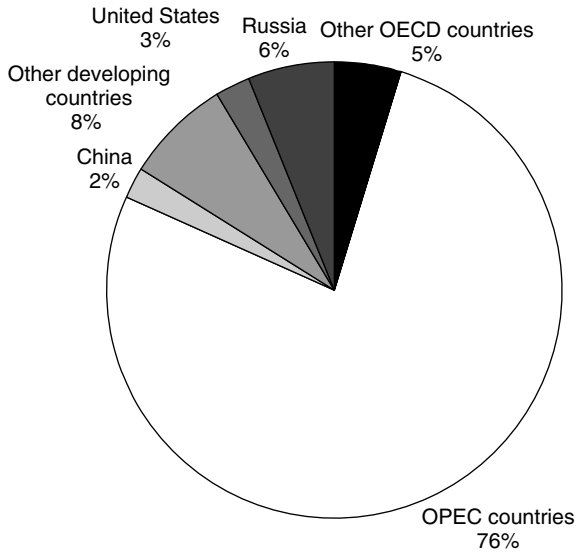


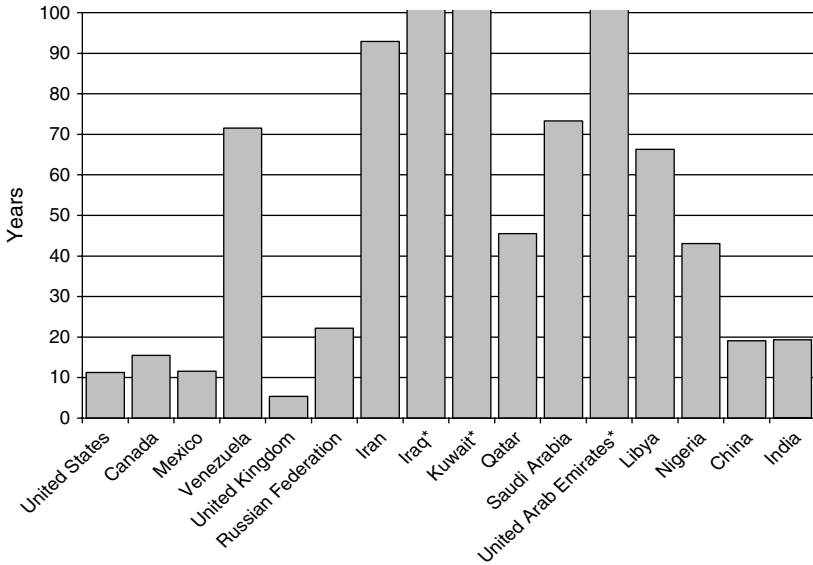
Figure 2.17. World crude oil reserve distribution.  
Source: BP 2004.

remaining 8% of estimated reserves are located in other developing countries (BP 2004).

While global  $R:P$  ratios are in the 40-year range, some countries have an  $R:P$  of over 100 years, while others have an  $R:P$  of under 10 years (Figure 2.18). OPEC members have a cumulative  $R:P$  of approximately 80 years. The rest of the world, excluding the former Soviet Union, has an  $R:P$  of only 13.6 years. The United States has an  $R:P$  of only 11.3 years.

Natural gas reserves follow a similar pattern to the distribution of oil reserves. The highest concentrations of natural gas are in Russia and OPEC nations. OECD nations, which consume more than half of the world's natural gas, have under 10% of world reserves (Figure 2.19). While Russia consumes approximately 16% of the world's natural gas, it holds over one-fourth of the reserves. OPEC member countries, meanwhile, hold just under half of the world's natural gas reserves (BP 2004).

This uneven distribution and consumption results in varying reserve-to-production ratios (Figure 2.20). While the United States and other developed countries such as the United Kingdom and Canada have reserves sufficient to last fewer than 10 years at current production levels, others have hundreds of years of supply. Because of Iraq's large supply and comparatively low level of production, their  $R:P$  is over 1000 years. China and India, where consumption levels are increasing as they



\* Crude oil R:P exceeds 100 years.

Figure 2.18. Crude oil reserve-to-production ratios for selected countries.  
Source: BP 2004.

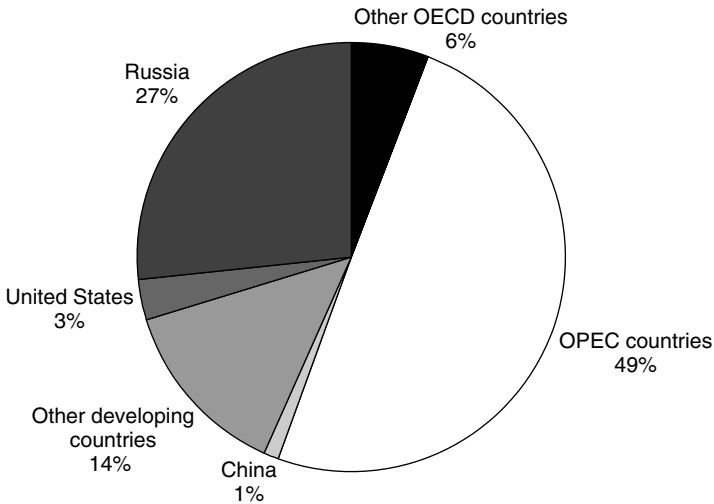
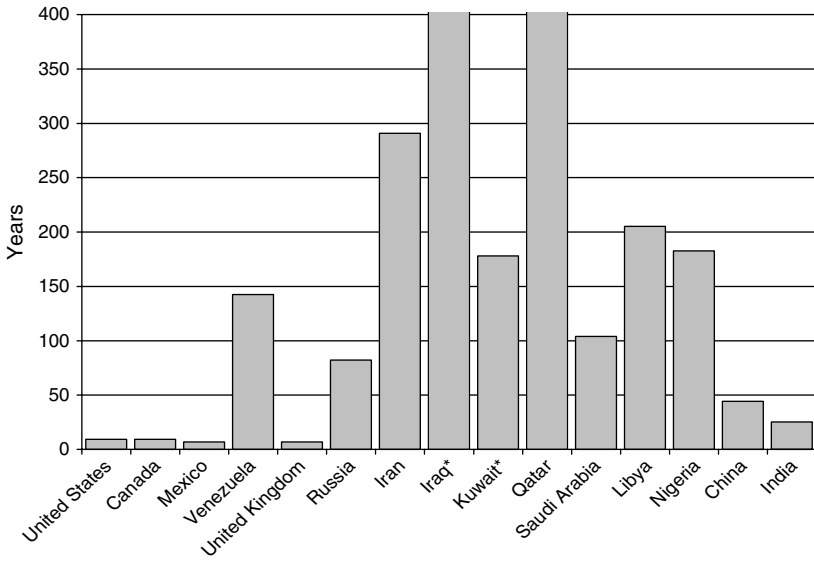


Figure 2.19. World natural gas reserve distribution.  
Source: BP 2004.



\* Natural gas R:P exceeds 400 years.

Figure 2.20. Natural gas reserve-to-production ratios for selected countries.

Sources: BP 2004; EIA 2005b; Oil & Gas Journal 2003.

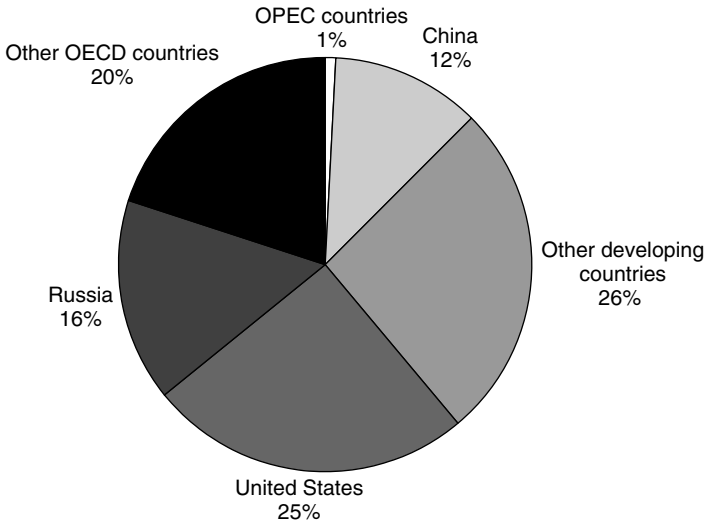


Figure 2.21. World coal reserve distribution.

Source: EIA 2004d.

develop, have approximately 53-year and 28-year supplies, respectively. Russia, which has the single largest reserves of any country, has supplies sufficient to last approximately 81 years (BP 2004).

While natural gas and oil reserves are highly concentrated in Russia and OPEC countries, coal reserves are more plentiful, and distributed in other parts of the world (Figure 2.21). North America, Asia and Oceania, and Eastern Europe and the former Soviet Union collectively have approximately three-quarters of the world's coal reserves. While OPEC member nations have large reserves of oil and natural gas, they have only 1% of the world's coal reserves. Coal reserves are especially prominent, however, in some of the largest energy consuming countries such as China and the United States. Reserve-to-production ratios of coal indicate that global supplies of coal will last over 200 years at current production levels (EIA 2004d).

In summary, oil and natural gas reserves are heavily concentrated in OPEC nations and Russia while coal reserves, which are far more abundant, are found in other parts of the world, including the countries with the highest levels of consumption. Political and economic ramifications of the scarcity and distribution of oil and natural gas are significant and complex.

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# Chapter 3

## Energy Security

We do have to do something about the energy problem. I can tell you that nothing has really taken me aback more, as secretary of state, than the way that the politics of energy is - I will use the word 'warping' diplomacy around the world. It has given extraordinary power to some states that are using that power in not very good ways for the international system, states that would otherwise have very little power.

US Secretary of State Condoleezza Rice, 2006 (Krishnaswami 2006)

Over the last half century, the world economy has become increasingly integrated and interdependent. Nowhere is this more self evident than in the global oil market. Disturbances or even threats of disturbances in any of the major oil-producing countries such as Venezuela, Nigeria, Iraq, Saudi Arabia, or Russia can send shock waves through the system, raising oil prices and adversely affecting economic growth. Six Persian Gulf countries (Saudi Arabia, Iran, Iraq, Kuwait, the United Arab Emirates, and Qatar) and Russia hold 69% of the world's proven oil reserves. These seven countries have 68% of the world's proven natural gas reserves (Russia, Iran, and Qatar alone have 57%). As the global economy expands and oil and natural gas demand grows, the world will become increasingly dependent on this unstable region for its oil and natural gas, suggesting increased risks of supply interruptions.

The distribution of world resources forces industrialized nations, which are the largest consumers of energy, to be dependent on developing nations for energy (Figure 3.1). Unfortunately, many of the main oil-producing countries, such as those in the Persian Gulf and Russia, are not the most stable countries. As the US secretary of state has learned, the industrialized world's addiction to oil shapes foreign policy.

Robert Baer, a former CIA analyst turned author, paints a bleak picture in *Sleeping with the Devil* of how the United States and other industrialized countries have turned a blind eye to corruption, violations of basic human rights, and petrodollar ties to known terrorists, in order to keep

Major trade movements  
Trade flows worldwide (million tonnes)

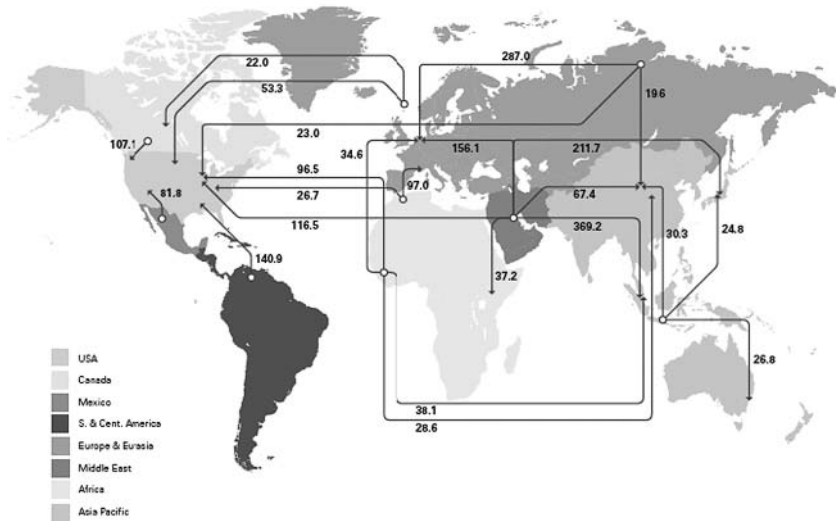


Figure 3.1. Dependence on oil from unstable regions is high.  
(Source: BP, 2006).

the oil flowing. He writes, “So we crow about democracy and talk about someday weaning ourselves from our dependence on foreign oil, despite the fact that as long as America has been dependent on foreign oil there has never been an honest, sustained effort at the senior governmental level to reduce long-term US petroleum consumption” (Baer 2003).

The situation in Saudi Arabia, the world’s largest oil producer, is particularly worrisome. Baer predicts that “sometime soon, one way or another, the House of Saud is coming down.” The huge swings in oil prices over the past couple decades have, during periods of low oil prices, wreaked havoc on the Saudi economy. While high oil prices strengthen the economy and therefore the sitting government, history suggests lowered prices will follow. Prior to the 2005–2006 price peak, Saudi per capita income fell from over \$28 000 in 1981 to under \$7000 in 2001 (Baer 2003). As per capita income fell, discontent rose and increased fundamentalists’ calls for an overthrow of the royal family. Clearly, should a major governmental shift in Saudi oil policy occur, the implications for the rest the world would be huge. No other country could fill the void should Saudi oil disappear from world markets. The result would be skyrocketing oil prices and economic havoc worldwide.

Natural gas markets historically have been less vulnerable to the supply interruptions common in oil markets, as long distance transportation

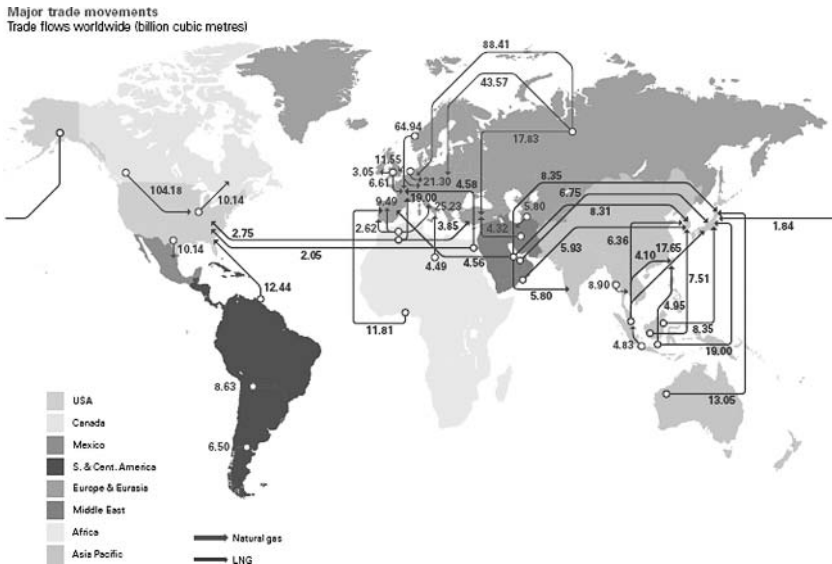


Figure 3.2. Natural gas dependency is growing (LNG).  
(Source: BP, 2006).

was an expensive proposition that made the natural gas markets regional in nature. But growth in cross-border pipelines (e.g., from Russia and Algeria to Western Europe) and the reduced costs of producing and transporting liquefied natural gas (LNG) have begun to create a global natural gas market as well (Figure 3.2). In the United States, for example, both a new natural gas pipeline from Alaska through Canada and a substantial increase in LNG imports are being contemplated through 2025. Such a global natural gas/LNG market will help foster global competition in natural gas, leading to better allocation of resources. At the same time, it may build a new natural gas interdependency and energy security vulnerability, similar to oil. And the consequences of natural gas supply interruptions could be more severe. Most countries, including the United States, use a larger share of natural gas than oil to generate electric power, and that share is expected to grow over time.

### Strategic Value of Oil

Oil historically has played a key strategic role in times of war: "Indeed, in the twentieth century, wars were fought over, or even decided by access to oil" (Noreng 2002). During World War II, for example, the allied forces had greater access to oil than Italy, Germany, and Japan, which were forced to create synthetic fuels through a costly and inefficient

process. In *The Prize*, Daniel Yergin (2001) recounts how adequate access to oil among allied forces was instrumental to victory.

Noting the importance of oil from both a strategic and economic standpoint, some countries such as the United States, France, and the United Kingdom historically have sought strong ties to countries with oil, especially in the Middle East.<sup>1</sup> In recent years, other countries, most notably China, have sought to secure access to oil supplies outside their borders. Sanger (2006) notes China's "search for oil is merging with its desire for greater influence, from Africa to Latin America to the Middle East." As discussed more completely in Chapter 2, the Chinese demand for oil will continue to grow as the country rapidly industrializes. The Chinese have made deals with Kazakhstan, Russia, Canada, and even countries the United States and others have shied away from, such as Sudan, Iran, and Burma. The deal between Sinopec, China's state-owned oil company, and the Iranians is valued at \$70 billion (Sanger 2006) and, suggest Sanger and others, is a major reason why China was not willing to support sanctions against Iran in 2006 for moving forward with enrichment of uranium in clear violation of international agreements.

### **Economic Oil Security**

The economic effects of an integrated global market dependent on only a few nations to supply a primary economic input threaten the stability of the global economy. Michael Toman of the Brookings Institute, a Washington, DC, think tank, contends that international economic oil security is determined by two major factors: the market power of OPEC and the macroeconomic instability due to price disruptions (Toman 2002).

Since the oil embargo of 1973, there have been just three periods of price stability: 1974–1978, 1981–1985, and 1991–1997. The various oil supply shocks and resulting price fluctuations have had devastating effects both on oil suppliers and consumers. Plummeting oil prices in the mid-1980s devastated US oil producers; the Houston and Denver economies were particularly hard hit. High prices have both frustrated consumers and been partly to blame for various recessions.

Figure 3.3 illustrates the connection between oil prices, economic growth, inflation, and unemployment rates. The price shock of the early 1970s resulted in a 2-year recession. When oil prices hit new highs in the

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<sup>1</sup> Yergin's book, *The Prize*, does an excellent job of describing the history and importance of oil over time.

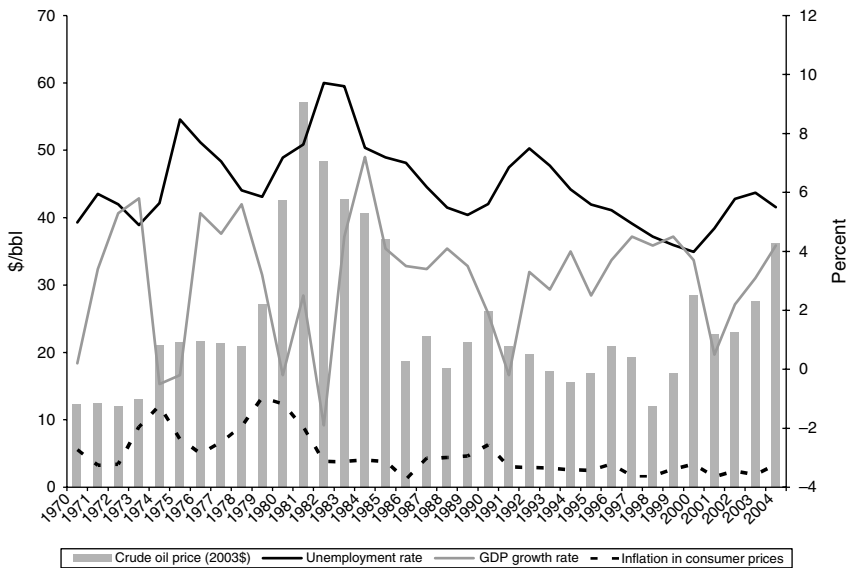


Figure 3.3. Oil price vs. United States GDP growth rate.  
(Source: EIA, 2006f; Economagic.com).

late 1970s, the United States experienced negative GDP growth ( $-2\%$ ). Since 1970, every recession in the United States was preceded by a sudden increase in the price of oil.

Unemployment rates also have increased during periods of high oil prices. Whereas unemployment rates typically were in the 5–6% range in the United States, rates reached as high as 9.7% in the late 1970s and early 1980s. As a primary input into the economy, the price of oil also has a significant effect on the total consumer price index. Inflation rates, typically in the 3% range from 1970 to 2005, peaked at more than 13% in the late 1970s and went under 2% when prices were low.

While oil has become a globally traded commodity, with prices subject to overall supply and demand, small changes in overall supply or even concerns about potential threats to supply can significantly affect prices. And while OPEC countries do not set prices, they do have tremendous market power, largely because oil demand is relatively unresponsive to changes in price. Economists define the overall responsiveness of demand to price changes as the “elasticity of demand.” An elasticity of  $-1.0$  means that for a 10% increase in price, demand decreases by 10%.

Consumers complain about increasing prices, but few change driving habits as a result. David Greene at Oak Ridge National Laboratories

(ORNL) estimates that the short-run elasticity is only  $-0.075$  and the long-run elasticity is approximately  $-0.5$ , which, while significantly higher, is still fairly inelastic (Toman 2002). This means that for each 10% increase in the price of gas, overall demand will only fall about 0.7% in the short term. In the short run, because there are no real substitutes for oil and it is a primary input in many facets of the economy, there is very little ability to reduce consumption in response to increased prices, especially in the transportation sector. For a longer period of sustained prices, consumers could react to higher prices by buying more efficient vehicles and altering living habits. Over this longer time period, the sustained 10% increase in prices would lead to a 5% decrease in demand.

Although oil is bought and sold globally, the market is not perfectly competitive due to OPEC's ability to manipulate prices through production quotas. Countries such as the United States, which are dependent on these sources, are subject to three types of economic losses: sluggish GDP, macroeconomic adjustment costs, and the transfer of wealth to oil-producing countries.

David Greene and Nataliya Tishchishyna (2000) estimate that under a truly competitive market, oil would be priced at about \$11 per barrel. By comparing historical oil prices to estimates of oil prices under a competitive system, Greene and Tishchishyna estimate an overall economic loss for the United States of approximately \$7 trillion over the period 1970 through 1999.<sup>2</sup> Of this amount, the largest component was the potential GDP loss, which accounted for \$3.4 trillion, followed by transfer of wealth accounting for \$1.2 trillion. Macroeconomic adjustment costs were estimated to be \$1.16 trillion.

### **Modeling and Forecasts of Future Oil Price Shocks**

Several models, including the International Monetary Fund (IMF) and ORNL, use historical data to predict the economic effects of oil price increases on various components and measures of the United States and the global economy. The IMF model (Mussa 2000) predicts that a \$5 increase in the price of oil per barrel initially would reduce real GDP by about 0.3% and reduce demand by 0.4% among industrialized countries. This impact is slightly higher in the United States and Euro regions than in other industrialized countries (Mussa 2000).

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<sup>2</sup>In order to conduct their analysis, Greene and Tishchishyna made several assumptions regarding price and supply elasticities. Short-run price elasticity was assumed to be  $-0.052$ , while long-run price elasticity was assumed to be  $-0.394$ . Additionally, they assumed that if the price of oil increased from \$15 per barrel to \$25 dollars per barrel over 20 years, the United States would increase its oil production by 15.6% by 2010.

The Energy Information Administration suggests the following “rule-of-thumb” for predicting the price effects of a decrease in supply and the effects of that price change on United States GDP: each 1 mbd reduction in supply results in a \$4–\$6 increase in the price per barrel (EIA 2006d). Furthermore, every 10% increase in the price of oil results in a 0.05–0.1% decrease in US GDP growth, with the first-year impact on the low end of that range and second-year impact on the high end.

Given an oil price of \$40 per barrel, rules of thumb would be combined in the following way to estimate the impacts of a disruption. For every 1 million barrels per day of oil disrupted, the price rule of thumb suggests that oil prices could increase by \$4–\$6 per barrel, or by 10%–15%. The GDP rule-of-thumb suggests that if these price increases were sustained, the U.S. GDP growth rate could be reduced by 0.05–0.15 percentage points. (EIA 2006d).

As discussed previously, oil prices are controlled by OPEC member countries and their ability to alter supply. The political situation within OPEC member countries is complicated and dynamic, especially in the Middle East. According to the Center for Strategic and International Studies, 50% of the world’s resources come from highly unstable countries. Additionally, “a crisis in one or more of the world’s key energy-producing countries is highly likely at some point during 2000–2020” (CSIS 2002). Furthermore, 10 of the top 14 exporting countries potentially are politically unstable (CSIS 2002).

Foreign influences as well as domestic and regional conflicts historically have affected Middle East politics. Relationships formed at the beginning of the twentieth century remain both sources of mutual benefit and sources of conflict within the region. The lack of representative governments and the presence of corruption in these nations also creates instability.

### **Historic Price Instability**

Prior to the 1970s and the formation of OPEC, oil prices remained fairly stable. In 1973, Arab oil-exporting nations including Saudi Arabia, Kuwait, the United Arab Emirates, and Iraq initiated an oil embargo against the United States as retaliation for US support of Israel during the 1973 Yom Kippur Arab–Israeli War. Before the embargo ended in 1974, world crude prices had tripled, and industrialized nations suffered huge economic losses (EIA 2004a). More than anything else, the embargo highlighted the US economy’s inherent vulnerability to oil-import interruptions (Figure 2.4).

Prices began rising again in 1979 with the Iranian revolution, subsequent fall of the western-friendly Shah, and the seizing of hostages at the US embassy in Iran. With the onset of the Iran–Iraq war in September 1980, prices quickly soared. OPEC member countries chose to cut output to keep world prices high. By 1981, OPEC’s total output was 7 mbd below their 1978 levels of 22.8 mbd (EIA 2004a). Oil prices moderated somewhat in 1981 due to increased output from Saudi Arabia. However, the extreme price increase had prompted exploration in other regions and conservation efforts in many countries, which led to a lowered market share for OPEC countries.

To keep prices high, in 1982 OPEC initiated a series of production quotas. Individual quotas for OPEC members were based on reserve estimates and historical production levels. The production quotas met with mixed success. The incentive for individual countries to cheat led to overproduction. For several years, Saudi Arabia played the role of swing producer, cutting supply to keep prices at its target levels. From 1980 to 1985, Saudi production dropped from 10 mbd in 1980 to 2.3 mbd in 1985 (Figure 3.4) (EIA 2004a).

Fed up with overproduction by other member nations and concerned about its own dwindling market share, Saudi Arabia abandoned its role

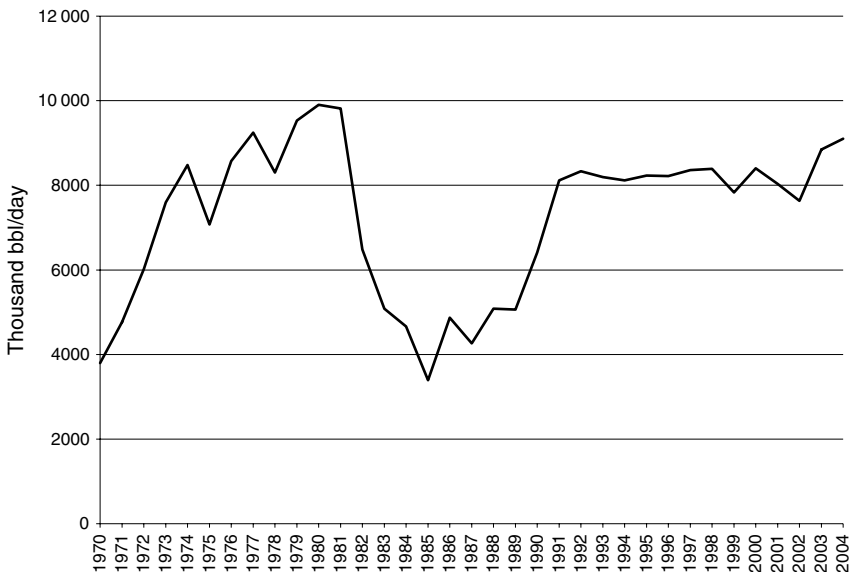


Figure 3.4. Saudi Arabia oil production, 1970–2004  
(Source: EIA, 2006g).

as swing producer in late 1985 and sharply increased production. Other OPEC member nations realized the need to hold on to market share and likewise expanded production. This increased supply sent oil prices plummeting from a peak of \$34 per barrel in 1983 to \$16 per barrel in 1987 and \$13 in 1989 (EIA 2005b). Just as higher prices led to decreased consumption and increased exploration and production in non-OPEC countries, this drastic cut in prices had the opposite effect.

Prices again peaked with the Iraqi invasion of Kuwait in 1990 and the subsequent Gulf War. The price hikes were further exacerbated when the United Nations approved an embargo of all crude oil and oil products originating in Iraq. Prices quickly fell as the Iraqis were driven from Kuwait.

### **Current Areas of Instability**

The political instability in the Middle East and other OPEC nations is not expected to change in the near future. Concerns for the future of oil-market stability are rooted in political volatility and infrastructure insecurity. In addition to continued instability in the Middle East, especially in Saudi Arabia, Iran, and Iraq, the politics of other OPEC nations such as Nigeria and Venezuela also pose a risk to the oil supply. Further uncertainty arises when new suppliers enter the market; their cooperation with OPEC also may be unclear. Much of the political instability in OPEC member nations is rooted in the problems of centralization of power, illegitimacy of governments, economic dependence on a single source of revenue, and economic hardships. Authoritarian Middle Eastern governments often are established, not through elections, but through coups or deaths in the ruling families (Noreng 2002). The same is true of some non-Middle Eastern OPEC nations.

Another area of instability lies in oil transportation's extensive infrastructure. The hub-and-spoke system in importing and exporting countries remains vulnerable to attacks. Targeting a few key points for attack could cause catastrophic supply flow problems.

#### *Political instability*

As of 2006, the only country with any excess oil capacity was Saudi Arabia. According to the US Department of Energy, production in most non-OPEC countries is controlled by the private sector. "Private companies do not hold back profitable production, and maintain very little spare production capacity. Hence, in the case of a significant world oil production disruption, OPEC (rather than private oil companies) would be the primary immediate source of additional oil to displace the loss,"

according to the EIA (2006e). Its excess capacity of 2 mbd makes Saudi Arabia particularly important to market stability; it is the only country that can, almost instantaneously, affect the world price of oil or prevent price shocks. But tensions within the royal family and between the royal family and Saudi citizens are a long-term concern.

The House of Saud, the royal family that rules Saudi Arabia, controls over one-fifth of the world's total resources. This income allows the family to dominate a country that is in many ways at war with itself. Tension within the royal family arises from debate over political reform, corruption in the royal family, and the tenuous relationship between Saudi Arabia and the United States (Baer 2003; Noreng 2002). When King Fahd suffered a debilitating stroke in 1995, leaving his half brother, Abdullah, as the defacto leader, there was widespread concern about the country's future direction and whether it would remain friendly to Western countries.

King Fahd's death in August 2005, at the age of 84, left Abdulla as the successor. Since Fahd's death there has been no significant modification in the oil policies of Saudi Arabia, even though many analysts once had feared Abdullah would make radical changes in an attempt to halt rampant corruption and the treasury-draining stipends given to the thousands of Saudi princes. Any major changes, however, will require the support of the conservative Sudairi strain, including several high-powered members of the royal family who want to preserve the status quo (Petroleum Economist 2005). Furthermore, even before becoming king, Abdullah was working with the US government to mend relationships tested by the 11 September 2001, attacks on Washington, DC, and New York City (Dourian et al. 2005).

The country's economic dependence on oil means that its price determines the standard of living. For example, when the price of oil is high, as it was in 1981, per capita income was \$28 600. When oil prices plummeted in subsequent years, so did per capita income, to less than \$7000 in 2001 (Baer 2003). Saudi Arabia's rapid population growth of 2.4% per year compared to the United States' rate of less than 1% (CIA 2004) also lowers the average standard of living.

Baer (2003) and others argue the United States was aware of Saudi financial support for terrorists long before the September 2001 attacks, in which the majority of hijackers came from Saudi Arabia. Financial ties to groups such as al Qaeda are part of the Saudi's tough balancing act: the need to appease Islamic fundamentalists and yet remain friendly with Western countries that buy their oil. A United Nations report indicated that in the last decade Saudi Arabia has funnelled \$500 million to the al Qaeda network (Baer 2003).

Within Saudi Arabia, there also is a strained relationship with Western oil workers and their families. While Saudi people work for Saudi Aramco, the state-run oil monopoly, Westerners are responsible for the bulk of the managerial and design work. "As one energy expert affiliated with another state oil firm in the developing world put it: Think of the expatriates as the architects at a construction site. They do not do all the work by any stretch of the imagination, but should they leave, the remaining construction workers lack the vision and expertise to care [*sic*] the project to fruition," explained Zeihan (2004).

There have been many attacks on the foreign workers, forcing them to live in tightly secured enclaves, separated from the indigenous population. Attacks in May 2004 in Yanbu and Khobar killed at least 27 expatriates (Zeihan 2004). In an effort to drive the Westerners out of the country, the assaults largely have focused on the expatriates and not on infrastructure. Should increasing numbers of foreign workers be killed or forced from work, the Saudi people may be able to run day-to-day operations and keep the oil industry afloat in the short term, but long-term abilities will be compromised. As a result, recovery rates and capacity may decrease and ultimately threaten the ability of Saudi Arabia to act as a swing producer stabilizing world oil prices.

Ironically, it appears that many in the West simply are unaware of the Saudi government's unstable nature. Yet, because of the sheer oil production capability of the Saudis, we should be very concerned. Any significant change could lead to sudden and potentially disastrous price changes in world oil markets – jeopardizing energy security. Without a fundamental change in world oil demand, little can be done to mitigate this anxiety. The oil-importing countries' energy and, hence, economic security is tied directly to stability in Saudi Arabia.

Other nations also have the ability to affect the price of oil. Prior to Iraq's invasion of Kuwait in August 1990, Kuwaiti oil production averaged approximately 2.9mbd. Following the war, production fell to as low as 305 000 barrels per day, but rebounded by 2002 to an average production level just over 2mbd.

After the United States and coalition forces invaded Iraq in 2003 at the start of the second Persian Gulf War, oil production in Iraq did not rebound as quickly as many analysts predicted at the onset. Iraqi production had been severely limited by the United Nations in the years prior to the invasion. Officially, Iraq was allowed to produce about 2mbd. The proceeds of those sales were intended to provide food and medicine to the Iraqi people and for war reparations to Kuwait. Baer (2003) discusses the huge black market in oil that flowed through Turkey and other countries as Iraq sought ways to avoid the strict production limits. Following the March 2003 invasion, production dipped as low as

53 000 barrels per day (EIA 2004b). By January 2004, Iraq had resumed pre-war output levels, which still were significantly below output levels in the years leading up to the 1990 Gulf War (EIA 2004b). While production continues to increase, a great deal of uncertainty remains surrounding the future yield.

It is not even clear whether Iraqi production can rebound to pre-1990 levels. Two of Iraq's biggest oil fields, Kirkuk and Rumaila, may have been over produced. Pumping oil too quickly can result in water leaking into the fields, making oil extraction more difficult and less economical. "Experts familiar with Iraq's oil industry have said that years of poor management have damaged the fields, and some warn that the current drive to rapidly return the fields to prewar capacity runs the risk of reducing their productivity in the long run," according to Gerth (2003). Some experts report that recovery rates from Kirkuk and Rumaila may be as low as 9 and 12%, respectively, using current technologies. These recovery rates compare to industry averages of 35–60% (Gerth 2003).

The stability and reliability of Iran as another key oil-producing country is questionable. First, Iran is plagued with high unemployment rates and poverty levels. Its economic situation is worsened by its expanding population – at a rate of 3% per year – while its GDP often is growing at a slower rate (Noreng 2002). Similar to other countries in the region, economic instability combined with the centralization of power threatens the legitimacy of the Iranian government. The governments of the Middle East are more stable at times of high revenues than when oil prices are low. High oil revenues result in a decreased need for taxes and, subsequently, a decreased need for legitimizing the government.

The ongoing negotiations that began in the mid-2000s about the future of Iran's nuclear programs have increased uncertainty about future oil supplies and have resulted in increased volatility in oil prices. Iran claims that its nuclear research and the onset of a uranium enrichment program are intended for its civilian nuclear ambitions. Many Western countries, including the United States, are opposed to allowing in-country enrichment of uranium. International negotiations stalled as the Iranian government resisted efforts by other countries to restrict its nuclear development. Iran repeatedly warned that any military action or economic sanctions would lead to cutbacks in oil exports. Just the uncertainty associated with the ongoing negotiations was at least partially responsible for 2006's record oil prices.

Oil-producing countries outside of the Middle East also suffer from political unrest. In 2003, a strike by government workers in Venezuela led to a drastic drop in oil exports. Venezuela supplied only 390 000 barrels per day in January 2003, down from approximately 3.2 mbd in 2002 (EIA 2003). While the general strike ended in non-oil sectors of

the economy in February 2003, PDVSA, the state oil company, suffered heavily as President Hugo Chavez fired nearly half of the firm's staff (Zeihan 2004). This purge left huge holes in the technical and managerial infrastructure and has led to continued lower production from Venezuela since the strike. In June 2006, production averaged 2.5 mbd, still below pre-strike levels.

Since the 1990s, Nigeria, the eighth-largest oil-producing country, has been plagued by violent clashes between various ethnic and religious groups. After years of military rule, the Nigerian government returned to civilian rule in 1999. Since the election of President Olusegun Obasanjo, however, the country has experienced severe unrest resulting in the deaths of thousands of Nigerians and strikes, hostage-taking, and work stoppages (Encarta 2004; United States Department of State 2003). Nigeria also was ranked the second most corrupt nation in 2002 based on the perceived abuses of power by both business and government (Lewis 2002) another factor threatening the stability of oil production. An example of this instability leading up to the 2003 presidential election in April 2003 was cited by Bredemeier (2003): "Nigeria's production of 1.9 million barrels a day . . . [was] trimmed by 800 000 barrels as several major producers pulled out their workers because of tribal warfare near the oil fields and civil unrest in advance of planned April 19 national elections."

### **Infrastructure Vulnerability**

The infrastructure that delivers oil from producers to consumers is vulnerable to terrorist attacks. Targeting a few specific points could shut down nearly the entire infrastructure, with devastating consequences. The pipeline, refining, and sea transport systems are particularly imperiled. The EIA recognizes seven major choke points in the oil transportation system: Bab el-Mandab, the Bosphorus/Turkish Straits, Druzhba pipeline in Russia, the Strait of Hormuz, the Strait of Malacca, the Suez Canal, and the Panama Canal. The most crucial of these would be the Strait of Hormuz, which, if closed, would divert 13 mbd to longer transport routes (EIA 2006c).

In addition to transportation routes, processing facilities in Saudi Arabia, if destroyed, also could significantly impact the flow of oil. Baer (2003) writes about the vulnerability: "Various confidential scenarios have suggested that if terrorists were simultaneously to hit only a few sensitive points 'downstream' in the oil system . . . they could effectively put the Saudis out of the oil business for about two years. And it just would not be that hard to do." For example, if the world's largest oil-processing facility, the Abqaiq complex located near the northern end

of the Gulf of Bahrain, suffered a moderate to severe attack, production would drop from 6.8 to 1 mbd (Baer 2003).

Some observers suggest the United States' oil infrastructure is also vulnerable. Lovins suggests "domestic oil infrastructure is so vulnerable that a handful of people could halt three-fourths of the oil and gas supplies to the eastern United States in one evening without even leaving Louisiana" (Lovins 2006). The National Research Council Committee on Science and Technology for Countering Terrorism points out several characteristics that determine the level of vulnerability of oil, natural gas, and electricity infrastructures in the United States: long transmission distances through isolated areas (1 280 000 miles in the case of natural gas and 220 000 miles in the case of oil), remote control of transmission, the ability to store the fuel, and importation availability (NRC 2002). While the risk of an oil infrastructure attack is lower than that of energy systems, the oil infrastructure suffers from a centralization of refining capacity, with 40% in Texas and Louisiana. Additionally, 60% is delivered to the Northeast through pipelines (NRC 2002).

#### *Infrastructure insecurity demonstrated by Katrina and Rita*

Terrorists are not the only threat to the oil and natural gas infrastructures. On 29 August 2005, Hurricane Katrina made landfall just east of New Orleans, Louisiana, with winds as high as 175 miles per hour. Only weeks later, Hurricane Rita hit the Gulf Coast region again, making landfall along the Texas and Louisiana border. The two storms clearly demonstrated US infrastructure vulnerability. Since 1975, refining capacity in the United States has remained relatively constant at the 2004 rate of just under 17 mbd. While refineries have expanded over the last quarter century, no new refineries have been built since 1976 (Mouawad 2005). Meanwhile, consumption of refined products such as gasoline and jet fuel has continued to rise. The result is a significant strain on capacity utilization (Figure 3.5). In 2004 capacity utilization was 93%, down from the 1998 high of over 95%. With no room to spare, any shock to the refining system could have a big impact on domestic energy markets (EIA 2006f).

Not only does the United States lack excess capacity, but much of its infrastructure is located in the Gulf Coast region, which accounts for 47% of total refining capacity in the United States. The Houston area is responsible for refining approximately 3 mbd, followed by the New Orleans area at over 1.2 mbd (API 2006).

Production in the Gulf region is also high relative to the rest of the country. Daniel Yergin (2005) argues: "The full extent of the Gulf of Mexico energy infrastructure is hard to grasp. Altogether, about 800

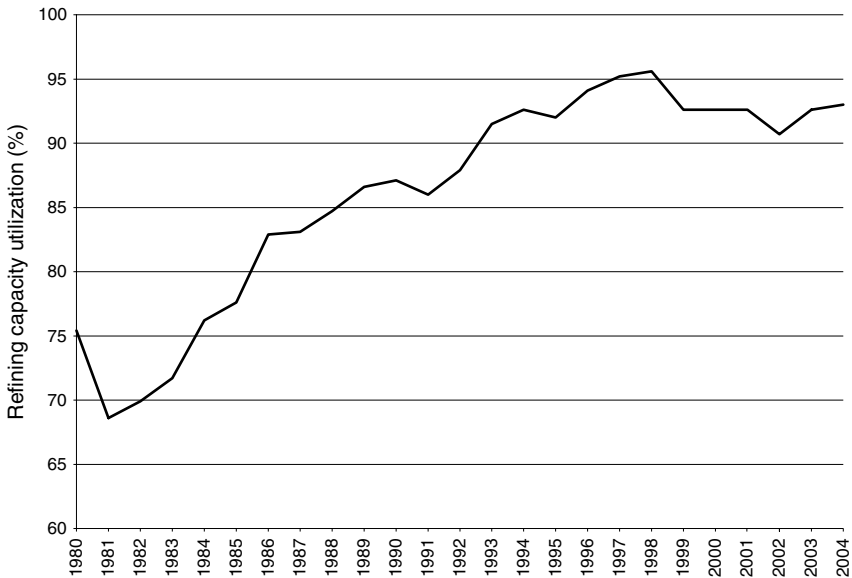
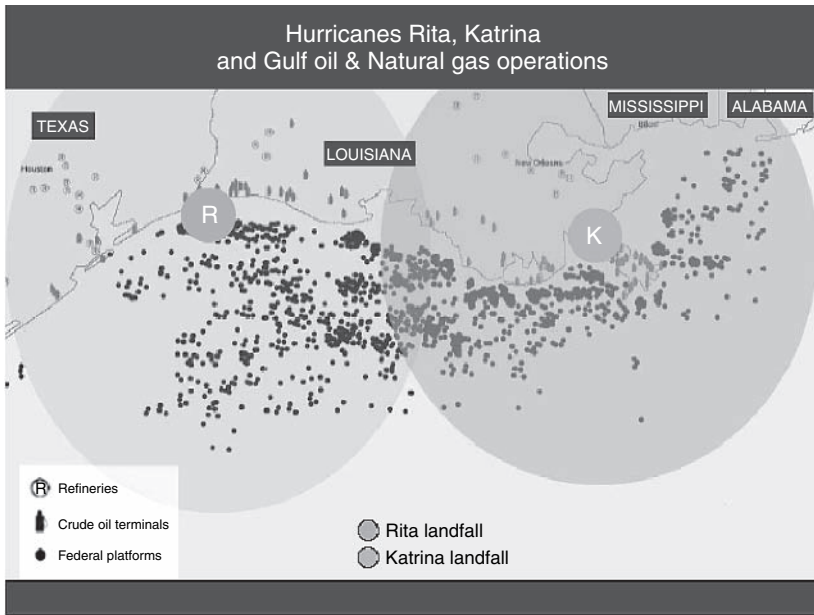


Figure 3.5. United States refining capacity, 1980–2004.

(Source: EIA, 2006f).

manned platforms, plus several thousand smaller unmanned platforms, feed their oil and gas into 33 000 miles of underwater pipelines, a good part of which eventually reaches shore at Port Fourchon at the mouth of the Mississippi. That adds up to 35% of domestic oil production . . . and over 20% of our natural gas coming from off shore.” In addition, approximately 60% of crude oil imports into the United States come through ports in the Gulf region (EIA 2005a) (Figure 3.6).

Hurricane Katrina temporarily shut-in approximately 1.5 mbd of Gulf oil and 10 billion ft<sup>3</sup> per day of natural gas from the Gulf (94% of total Gulf production) (MMS 2006). The Minerals Management Service (MMS) reported that “more than 90% of the manned platforms and 85% of working rigs were evacuated at one time.” As the storms hit, there was extensive damage to both the production and distribution infrastructures. “Katrina destroyed 46 oil platforms and damaged another 20 while Rita was responsible for the destruction of an additional 69 platforms and damaged another 32. The underwater pipeline infrastructure, which suffered extensive damage during Hurricane Ivan in 2004, was also badly damaged during the 2005 hurricane season” (MMS 2006). At the start of the 2006 hurricane season, infrastructure repairs still were not complete.



Copyright API, 2006

Figure 3.6. Gulf oil and natural gas infrastructure affected by Hurricanes Rita and Katrina.

Sources: NOAA, EIA.

A drastic increase in the price of crude oil, gasoline, and natural gas followed hurricanes Katrina and Rita. In addition to lost production capacity, there was a 10% loss in refining capacity immediately following Katrina, and a 27% loss in capacity following Rita (Slaughter 2005). To further compound the shortage of refined products, lack of electricity in the days following Katrina forced the closure of two major refined-product pipelines stretching from the Gulf Coast to the Southeast and Mid-Atlantic regions. The price of gasoline jumped approximately 75% in only 5 days to a record high of \$3.26 per gallon in New York. Prices reached over \$4 in other regions (Bajaj 2005). Meanwhile, natural gas futures prices increased 20%, and crude oil prices increased 6% (EIA 2006a; EIA 2006b) (Figure 3.7).

The hurricane season of 2005 brought to light two crucial issues for energy security in the United States. Not only is the country reliant on sources abroad for energy, we rely heavily on the Gulf area of the United States for much of the energy production, processing, and distribution. In addition, the lack of excess refining capacity only augments the effects of environmental shocks to the vulnerable region.

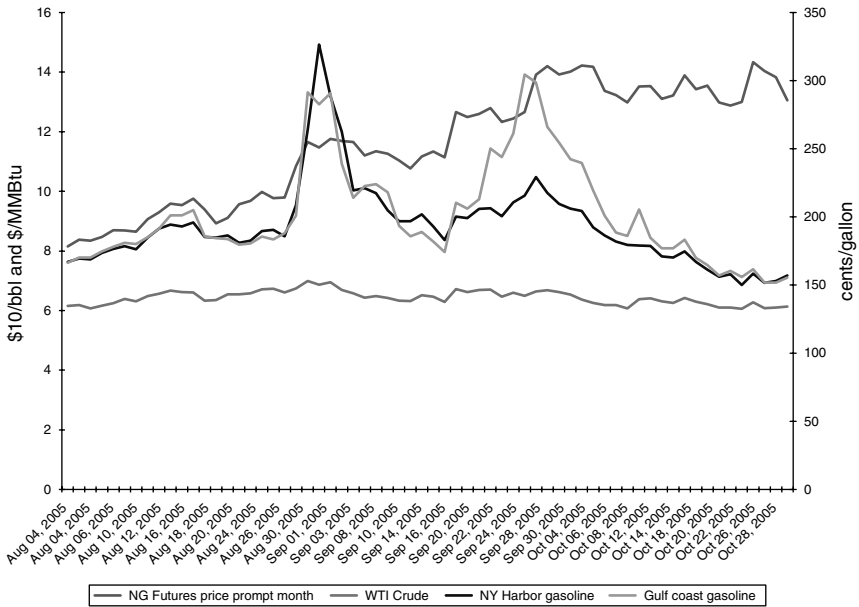


Figure 3.7. Natural gas, petroleum and gasoline prices prior to and following Hurricanes Katrina and Rita.

(Sources: EIA, 2006a; EIA, 2006b).

Energy security is a critical worldwide concern with many overlapping issues. In addition to national security questions stemming from the strategic importance of oil, economic stability in the oil market is crucial to a healthy global economy. Political vulnerability in OPEC member nations, especially the Middle East, threatens the strength of the oil market. Concern over regional and domestic disputes in the Middle East as well as relationships between oil exporters and importers creates uncertainty for the future. The fact that the global oil distribution system is centralized adds another potential threat to energy security. Large oil-consuming countries such as the United States cannot erase their vulnerabilities through oil exploration. Decreased consumption would help, as would the political stabilization of those countries that hold reserves. These are complex problems. Hydrogen offers an alternative energy source that could be part of the solution.

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# Chapter 4

## Environmental Concerns

The consumption of fossil fuels spawns environmental considerations in addition to issues of energy demand, national security, and resource availability. At the global level, scientists warn that the combustion of fossil fuels is significantly changing the world's climate system. Local or regional concerns include smog, acid rain, and health implications of urban air pollution.

### Climate Change

A diverse array of evidence points to a warming of global surface air temperatures. Instrumental records from land stations and ships indicate that global mean surface air temperature warmed about 0.4 to 0.8°C (0.7–1.5°F) during the 20<sup>th</sup> Century (NRC 2001).

The greenhouse effect is a natural occurrence responsible for the current climatic conditions on Earth. Without this natural effect, the Earth's temperature would be about 33°C colder (IPCC 2001a). The ultimate question is how the Earth's climate system will respond to the increasing concentrations of greenhouse gases (GHGs) caused by human activities. Figure 4.1 illustrates the greenhouse effect. Shortwave radiation from the sun enters the Earth's atmosphere. While some of this radiation is reflected by the atmosphere, most of the radiation reaches the Earth's surface, where it is absorbed. The Earth's surface reradiates this energy at a different wavelength, as infrared radiation. Some of this outgoing infrared radiation is absorbed and re-emitted by greenhouse gas molecules, which warms the Earth's surface and lowers atmosphere. As concentrations of GHGs increase, more of the infrared radiation is absorbed and reradiated back to Earth.

Greenhouse gases include water vapor, carbon dioxide, methane, nitrous oxides, and several largely man-made chemicals, including the halocarbons (chlorofluorocarbons [CFCs] and hydrofluorocarbons

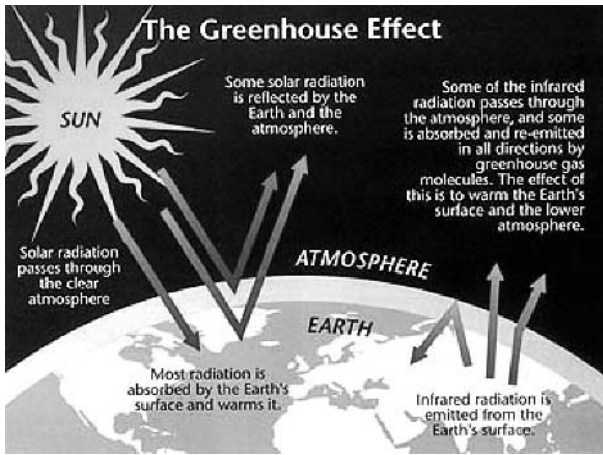


Figure 4.1. The greenhouse effect.  
(Source: NPS, 2006).

[HFCs]), bromines (halons, methyl bromide), perfluorocarbons (PFCs), and sulfur hexafluoride (SF<sub>6</sub>). With the exception of water vapor, these GHGs exist in very small concentrations in the atmosphere. The most prevalent of the GHGs, carbon dioxide (CO<sub>2</sub>), makes up just 0.037% of the atmosphere, or 370 ppm (Table 4.1).

As a result of human activities ranging from the combustion of fossil fuels to the use of nitrogen-based fertilizers to large-scale deforestation, concentrations of key GHGs are increasing. Increased concentrations of CO<sub>2</sub> coincided with the onset of the Industrial Revolution in the 1860s and the use of fossil fuels. Based on an analysis of ice cores, scientists

Table 4.1. Characteristics of the key greenhouse gases

Gas	Pre-industrial concentration	Current concentration	Annual rate of change <sup>1</sup>	Atmospheric lifetime (yr)	100-year GWP
CO <sub>2</sub> <sup>2</sup> (ppm)	278	373.1	1.58	50–200	1
CH <sub>4</sub> (ppm)	0.7	1.745	0.007	12	23
N <sub>2</sub> O (ppm)	0.27	0.314	0.0008	114	296
SF <sub>6</sub> (ppt)	0	4.2	0.24	3,200	22,200
CF <sub>4</sub> (ppt)	40	80	1	>50,000	5,700

<sup>1</sup> Rate of change calculated from 1990–1999, measured in ppm/yr or ppt/yr.

<sup>2</sup> Current atmospheric concentration is for 2002 and rate of change is calculated from 1990–2002.

Sources: EPA (2002), IPCC (2001b), and Keeling et al. (2004)

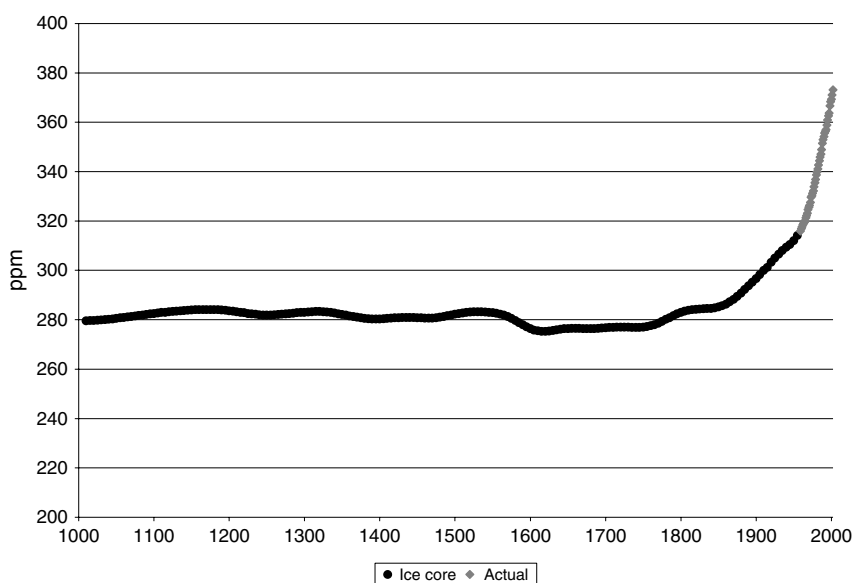


Figure 4.2. Carbon dioxide atmospheric concentration, 1000–2003.

(Source: Etheridge et al. 1998; Keeling et al. 2004).

concluded that until about 1860, concentrations of  $\text{CO}_2$  remained relatively constant at 280 ppm since the last ice age 10 000 years ago. Since the Industrial Revolution, however, concentrations have increased to just over 373 ppm (Figure 4.2), and currently are increasing by about 1.5 ppm per year. While natural fluxes of  $\text{CO}_2$  between the atmosphere, biota, and oceans occur on a very large scale, these processes are basically in equilibrium and do not contribute to the annual increases in atmospheric concentrations. The observed annual increase coincides with the large-scale combustion of fossil fuels and deforestation.

Methane ( $\text{CH}_4$ ) is released during the anaerobic decomposition of organic material, which occurs naturally in wetlands and bogs. Natural gas is primarily (95%) methane; leakages from the drilling and transmission of natural gas also are a significant source of methane (Drennen and Chapman 1992). Other sources include: rice paddies; leakages from landfills; enteric fermentation (the intestinal fermentation which occurs in animals such as cows); termites; and coal mining (venting of methane pockets). Until the 1990s, methane emissions were increasing at about 1% per year. The rate has slowed somewhat during the 1990s (NRC 2001), perhaps due to better management of landfills and natural gas handling.

Atmospheric concentrations of nitrous oxide have increased about 13% over the last 200 years (NRC 2001). There are many sources for nitrous oxide, including microbial activity in soils, denitrification of fertilizers, biomass burning, fuel combustion, and even lightning strikes.

Another key group of GHGs is the halogenated species, which includes CFCs, halon, and methyl bromide. As these gases are also known to destroy stratospheric ozone, they are regulated under the Montreal Protocol, an international agreement designed to protect the ozone layer. Unfortunately, several of the replacement gases, including hydrochloro-fluorocarbons (also a halocarbon), while ozone friendly, are powerful GHGs. Finally, other industrial gases, including perfluorocarbons, and SF<sub>6</sub>, are strong GHGs with the potential to become major contributors to future greenhouse warming.

Greenhouse gases are not all created equal in terms of their warming effectiveness. Methane, nitrous oxides, and CFCs, which combined make up less than one-thousandth of a percent, are more effective per molecule at absorbing the infrared radiation. This effectiveness determines the global warming potential (GWP), which compares the molecules' ability to absorb heat relative to the ability of CO<sub>2</sub>. On the basis of a 100-year time frame, methane has a GWP of 23, meaning that CH<sub>4</sub> is 23 times more effective per molecule at absorbing outgoing infrared radiation than is a molecule of carbon dioxide. Nitrous oxide has a 100-year GWP of 296, and CFCs, 4900–10 200, depending on the specific CFC (IPCC 2001b). Even accounting for these GWPs, CO<sub>2</sub> is the leading contributor to global warming (Figure 4.3).<sup>1</sup>

### *Effects of climate change*

The Intergovernmental Panel on Climate Change (IPCC 2001b), established by the international community in 1988 to provide unbiased scientific analysis regarding the potential for and effects of human-induced climate change, reports that global temperatures have increased 0.6°C (1.08°F) since 1861 (Figure 4.4) (IPCC 2001b). The panel further reports that "it is very likely<sup>2</sup> that the 1990s was the warmest decade and 1998 the warmest year in the instrumental record" (IPCC 2001b). More recently, NASA's Goddard Institute of Space Studies reported that

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<sup>1</sup> The CFCs are not included in this figure as they are being phased out under the terms of the Montreal Protocol.

<sup>2</sup> The IPCC groups its findings into levels of certainty. Very likely means that there is a 90–99% level of confidence.

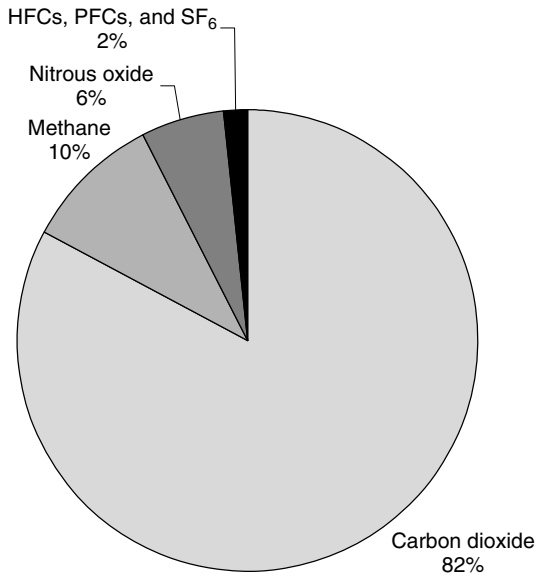


Figure 4.3. Relative role of various greenhouse gas emissions from United States in 2000 to greenhouse effect. (Source: EPA, 2002).

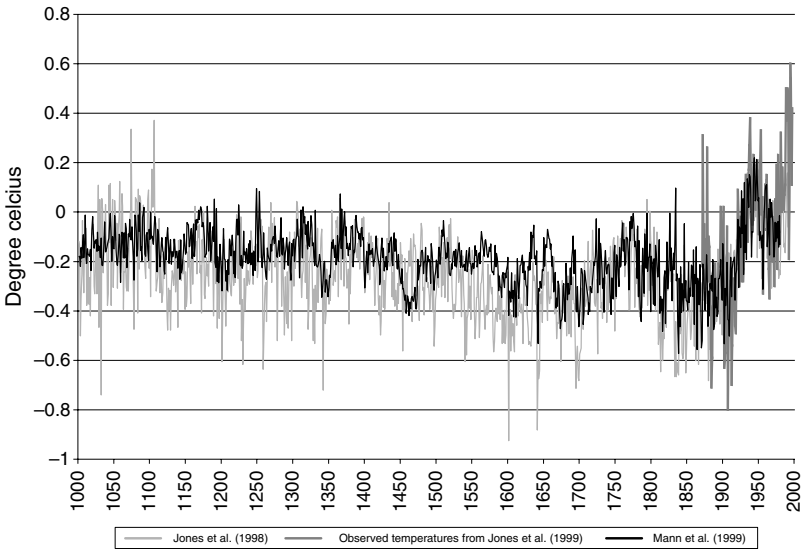


Figure 4.4. Global temperature anomalies, 1000–2000. (Source: Jones et al. 1998; Jones et al. 1999; Mann et al. 1999).

2005 was the warmest year on record, surpassing 1998. Goddard's Director, Dr James Hansen, states that the Earth's average temperature has increased one degree Fahrenheit over the last 30 years (Eilperin 2006).

The IPCC notes increased sea levels, decreased snow cover, and increased precipitation have resulted from this increase in temperature. Sea level rise occurs for two reasons: thermal expansion of the water and melting ice. During the twentieth century, the average global sea level rose between 0.1 and 0.2 m (0.3–0.7 ft) (IPCC 2001b). The IPCC reports that snow cover has decreased approximately 10% since the late 1960s. Additionally, precipitation increased over much of the northern hemisphere by as much as 1% per decade during the same time period (IPCC 2001b). The IPCC concludes that "most of the observed warming over the last 50 years is likely to have been due to the increase in greenhouse gas concentrations. Furthermore, it is very likely that the twentieth century warming has contributed significantly to the observed sea level rise, through thermal expansion of sea water and widespread loss of land ice" (IPCC 2001b).

Based on their analysis of various climate models, the IPCC predicts that global average surface temperatures from 1990 to 2100 will rise by 1.4–5.8°C (2.5–10.4°F), an increase larger than the entire twentieth century's and unprecedented in the last 10 000 years. The IPCC (2001b) reports that it is almost certain that CO<sub>2</sub> emitted through the combustion of fossil fuels will be the dominant source of increased atmospheric CO<sub>2</sub>. As the environment becomes further saturated with CO<sub>2</sub>, a decreased ability to absorb the gas will magnify the effect. The warming of the Earth's temperatures is predicted to melt glaciers and cause the thermal expansion of oceans, raising sea level as much as 0.88 m (2.9 ft) by 2100 (IPCC 2001b). Such increases will threaten small island states and other low-lying coastal areas, especially in developing nations (UNFCCC 1993). Climate change will increase the cycle of severe weather, including droughts and more frequent and damaging cyclones. While some regions may benefit from these climatic changes, overall there will be serious societal and ecosystem challenges.

IPCC's varying estimates demonstrate the considerable uncertainty about the magnitude of possible ramifications of increasing greenhouse gas concentrations. One reason for the wide range is a poor understanding of likely climatic feedback responses. As the Earth warms, for example, water evaporation and cloud cover increase, thus lowering temperatures. But while there is increased cloud cover at lower altitudes, the same feedback results in decreased cloud cover at higher altitudes. The total effect of this feedback mechanism is hard to estimate. A 2001 National Academy of Sciences (NAS) report notes that differing methods for dealing with this feedback mechanism in existing climate

models account for many of the predicted differences and that “these uncertainties will remain until a more fundamental understanding of the processes that control atmospheric relative humidity and clouds is achieved” (NRC 2001).

While the IPCC reports fairly high levels of confidence regarding the link in climatic changes to human activities, there still are skeptics of this causality. A professor of meteorology at Massachusetts Institute of Technology, Richard Lindzen, argues: “Since fluctuations on the order of 0.5°C occur from year to year within any climate record, the observed trend is still indistinguishable from normal climatic variability” (Lindzen 1990). Lindzen does not disagree with the basic premise that additional GHGs warm the planet, but rather argues that our understanding of the basic atmospheric relationships is too incomplete to predict future changes from increased concentrations of GHGs. “What we do know is a doubling of carbon dioxide by itself would produce only a modest temperature increase of one degree Celsius. Larger projected increases depend on ‘amplification’ of the carbon dioxide by more important, but poorly modeled, greenhouse gases, clouds and water vapor” (Lindzen 1990).

The wide range of temperatures presented by the IPCC illustrates the uncertainty in climate modeling. Lindzen (1990) points out several uncertainties in the climate system, including the feedback mechanisms, which he claims overestimate the total temperature change from the emissions of GHGs. Questions regarding the ability of computer models to accurately predict the future and the lack of consensus among models signal the need for a better understanding of the climate system, some say.

Noting the uncertainty surrounding climate change predictions as well as the potential economic harm of reducing greenhouse gas emissions, President George W. Bush in 2001 commissioned the NAS to evaluate the latest IPCC evidence. The NAS report agreed with the IPCC that the Earth’s warming over the last 50 years resulted from increased greenhouse gas concentrations (NRC 2001). However, the NAS emphasized the difficulty in differentiating between natural variations in the climate and human-induced variations: “Because there is considerable uncertainty in current understanding of how the climate system varies naturally and reacts to emissions of greenhouse gases and aerosols, current estimates of the magnitude of future warming should be regarded as tentative and subject to future adjustments (either higher or lower)” (NRC 2001). Reducing uncertainty in climate models requires advancing the understanding and modeling of determining factors that influence greenhouse gas concentrations and feedback mechanisms, the NAS said.

Following the NAS report, President Bush conceded that “there was a warming trend from the 1890s to 1940s. Cooling from the 1940s to

1970s. And then sharply rising temperatures from the 1970s to today” (Bush 2001). Still, Bush argued that sound policy responses require increased scientific certainty. “The Academy’s report tells us that we do not know how much effect natural fluctuations in climate may have had on warming. We do not know how much our climate could, or will change in the future. We do not know how fast that change will occur, or even how some of our actions could impact it” (Bush 2001). Unfortunately, resolving remaining uncertainties will take considerable time and effort. During this time, increasing concentrations of GHGs will force us to continue our large-scale experiment with nature and climate.

*Global contributions to climate change: who is responsible?*

Greenhouse gas emissions from any country depend on three factors: its energy intensity, fuel mix, and population.<sup>3</sup> Energy intensity, a measure of overall energy efficiency, is defined as a country’s energy consumption relative to its gross domestic product (GDP). As discussed in Chapter 2, energy use per capita varies widely from country to country. Some countries, notably the European countries, consume significantly less energy per unit of GDP than the United States. Therefore, a 2% increase in per capita GDP in the United States would mean a higher increase in carbon emissions than for a European country with lower energy intensity and similar fuel mix. Likewise, the overall energy mix of a country’s fuel consumption is very important. Countries with a higher fuel share of coal will emit more carbon per unit of fuel use than a country with a lower reliance on coal. Of the fossil fuels, coal has the highest per unit carbon content, followed by oil and natural gas.<sup>4</sup> Nuclear and renewable energy options do not result in carbon emissions. Finally, after adjusting for the other factors, a country’s population is a major factor in greenhouse gas emissions.

In 2001, the United States emitted 5692 million metric tons of carbon dioxide (MtCO<sub>2</sub>), approximately one-fourth of world carbon dioxide emissions (Figure 4.5), while Americans represent less than 5% of the world population (EIA 2005). Other industrialized nations combined emitted slightly more than the United States. Eastern Europe/former Soviet Union and China each were responsible for approximately 11%

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<sup>3</sup>Kaya (1990) developed the following simplified equation for understanding the factors that contribute to emissions:  $C_{net} = C/E \times E/GDP \times GDP - S$  where: C/E is the “carbon intensity” of the energy system, E/GDP is the “energy intensity” of the economy, and S is the carbon sequestered.

<sup>4</sup>Coal contains 1.3 times more carbon per unit of energy than oil and 1.8 times more than natural gas.

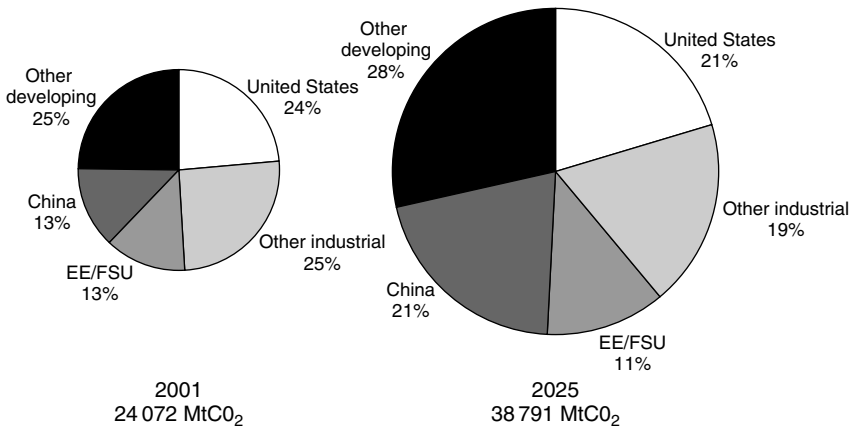


Figure 4.5. World distribution of carbon dioxide emissions, 2001 and 2025. (Source: EIA, 2005).

of emissions, leaving the rest of the developing world with one-fourth of carbon emissions and 73% of the population (EIA 2005). By 2025, the EIA estimates that global carbon emissions will increase by more than 50% over 2001 levels. Much of this growth will occur in developing countries. Emissions in industrialized nations are expected to increase by approximately 40%, while developing nations' emissions will nearly double. China's emissions are projected to increase from 3176 to 8133 MtCO<sub>2</sub>, a 2.5-fold increase (EIA 2005).

One of the largest contributors to carbon emissions is the transportation sector. In the United States, for example, the transportation sector accounted for approximately one-third of total carbon emissions in 2001. This is of particular concern when considering the drastic increase in vehicle use expected in developing countries in the coming years. Rapidly growing emissions in highly populated countries such as China and India will impact industrial emissions, which also account for a great deal of total carbon emissions (Figure 4.6).

Despite the expected doubling in emissions from developing countries, however, emissions based on a per capita (per person) basis will remain far below per capita levels in the industrialized countries (Figure 4.7). This will influence how to limit future emissions. For example, the EIA forecasts show United States emissions reaching 22.7 tons CO<sub>2</sub> per capita by 2025, while the average emission will be just 5.62 tons CO<sub>2</sub> per person in China, which is about one-fourth that of the average United States citizen (EIA 2005). This simple statistic demonstrates the inherent difficulty of attempting to deal with emissions by setting

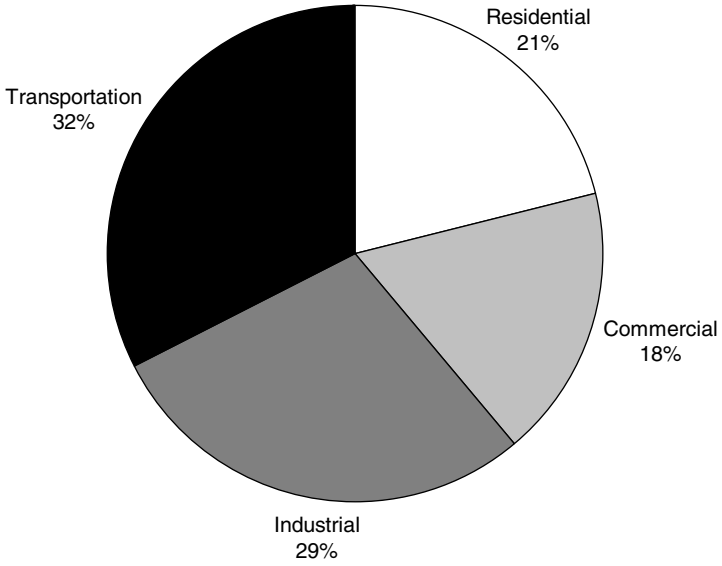


Figure 4.6. United States carbon emissions by sector, 2001. (Source: EIA, 2006).

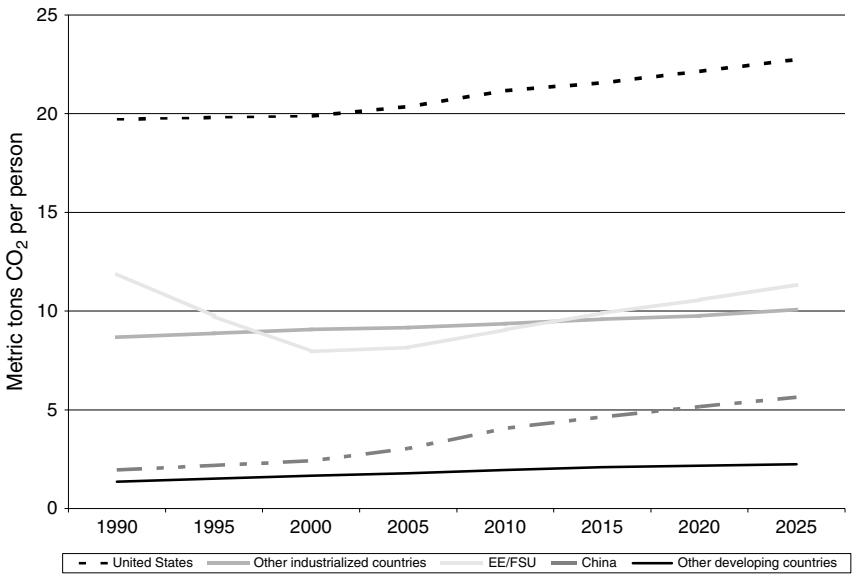


Figure 4.7. Per capita carbon emissions by region, 2001 and 2025. (Source: EIA, 2005).

international targets. Developing-country participants will be loathe to accept any agreement which limits their ability to be on par with the industrialized countries. China, where 75% of electricity is produced from coal, will not voluntarily limit its economic growth for the sake of reducing carbon emissions. This is why technological solutions, including fuel cells powered with hydrogen from non-carbon emitting sources, hold great promise for limiting future emissions of carbon.

### *The policy response to climate change*

In response to repeated warnings from scientists, the international community began negotiations in 1990 aimed at minimizing future emissions of key GHGs. Negotiations culminated at the 1992 Rio Earth Summit, during which 186 countries signed the United Nations Framework Convention on Climate Change (UNFCCC). The ultimate goal of the UNFCCC was “to achieve stabilization of atmospheric concentrations of greenhouse gases at levels that would prevent dangerous anthropogenic (human-induced) interference with the climate system” (UNFCCC 1992). The Framework Convention did not contain binding emission limits, relying instead on voluntary efforts by member countries. Perhaps most important was the convention’s requirement for countries to meet annually to assess new scientific evidence and overall progress towards achieving the goal. By 1997, it was obvious that the voluntary agreements would have little effect on growing emissions. At the annual meeting of the parties, countries adopted the Kyoto Protocol to the Framework Convention on Climate Change.

The Kyoto Protocol establishes targets for reductions from industrialized countries and goals for assisting developing countries in cleaner development. The Protocol covers six GHGs: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The Protocol calls for industrialized countries to reduce emissions 5.2% below 1990 levels. To achieve that reduction, each country or group of countries agreed to specific targets. For example, the United States agreed to reduce emissions to 7% below 1990 levels, while the European Community agreed to a reduction of 8%.

For the Kyoto Protocol to be binding on nations, ratification was required by 55% of the countries who, taken together, were responsible for 55% of 1990 emissions. This clause ensured that developing countries alone could not force implementation of the Protocol. Despite US and strong industrialized country support of the Kyoto Protocol in 1997, it took 8 years before the required number of countries ratified the agreement. The Kyoto Protocol entered into force on 14 February 2005, 90 days after ratification by Russia. As the United States had backed

away from the Protocol in 2001, it had come down to Russia to make or break the Protocol – without its ratification, Kyoto could not have reached the 55% requirement.

In announcing the United States decision to back away from the Protocol in 2001, President Bush cited scientific uncertainty, fundamental flaws in the Kyoto Protocol in terms of fairness, and potential economic harm from drastic climate change policy. Prior to its ratification, Russia sent out mixed signals about its intentions, noting that participation in Kyoto could make reviving its economy more difficult. As a “transitional economy” under the terms of the Protocol, Russia is in somewhat of a unique position. Russia was given special status, allowing the country to base its emission targets on 1988 emissions, prior to the fall of the Soviet Union. Since that time, Russian emissions have declined an estimated 30% due to the economic upheaval. As the Kyoto Protocol allows countries the option of trading permits, or emission rights, Russia stands to gain financially from large-scale permit sales. However, without the United States participating, the number of parties interested in buying excess Russian emission rights has decreased, lowering the potential market value of Russian permits. Russia’s hesitation may have been related to the realization that without the United States, its excess permits would not be very valuable. Another interpretation is that Russia was using Kyoto as a negotiating lever regarding its discussions with the European Union (EU) on joining the World Trade Organization (WTO). It was after Russia signed a trade deal with the EU in May 2004, giving Russia the EU’s blessing to join the WTO, that Putin announced Russia’s intention to ratify the Kyoto Protocol by noting that Russia would “speed up the movement on Russia’s ratification of the Kyoto Protocol” (Arvedlund et al. 2004).

While the Bush administration rejected further participation in the Kyoto Protocol, it does acknowledge the long-term threat posed by climate change. Bush’s current strategy is to seek technological solutions to limit future emission increases: “Addressing global climate change will require a sustained effort, over many generations. My approach recognizes that sustained economic growth is the solution, not the problem – because a nation that grows its economy is a nation that can afford investments in efficiency, new technologies, and a cleaner environment” (Bush 2002). Key among his proposals is the push for fuel cell vehicles and other climate-friendly technologies.

In early 2006, the Bush administration announced an initiative with key Asian-Pacific countries designed to accelerate the development and use of cleaner, more efficient technology. Under Secretary of State for Democracy and Global Affairs Paula Dobriansky stated that the partnership would promote economic growth, reduce poverty, and enhance

energy security, while “mitigating air pollution and greenhouse gas emissions” (Pellerin 2006). Dobriansky promised a US financial commitment for the initiative that “will build upon and complement our nearly \$3 billion annual investment to develop and deploy such cutting-edge energy technologies as hydrogen, carbon sequestration, nuclear energy, renewable fuels and electricity, and highly efficient appliances, vehicles and buildings” (Pellerin 2006).

Prior to its 2005 start date, several countries began efforts to meet their obligations under the Kyoto Protocol. In ratifying the agreement in May 2002, the EU signaled its intention to move forward despite the United States withdrawal: “The European Union’s ratification of the Kyoto Protocol is a clear indication that, with enough political will and collective social effort, the challenges of our time, complex though they may be, can be addressed successfully through instruments of multilateral cooperation” (EU 2002). A major component of the EU strategy for meeting its obligations is a community-wide emission-trading program that started in 2005. Theoretically, this will allow the European countries to meet their obligations in the cheapest way possible by allowing countries to purchase emission rights from other countries that can reduce emissions cheaply. The EU also has announced ambitious goals for renewable energy; its current goal is for 22% of its electricity and 12% of all energy to come from renewable sources by 2010 (Landler 2004), goals that may be very hard for the EU actually to achieve.

### **Other Environmental Concerns**

As an eerie grayish cloud settled over Los Angeles and surrounding communities last week, residents were advised not to exercise and to stay at home. Motorists were asked to stay off the highways, and polluting industries were told to reduce their emissions (Hollie 1978).

While GHGs pose a serious long-term threat to the environment, several other pollutants associated with current energy-use patterns threaten the environment and our health on a daily basis. Faced with the type of restrictions mentioned above in Los Angeles in the 1970s, the United States responded with far-ranging air and water quality regulations. Despite nearly a doubling of total vehicle miles driven from 1970 levels of 288 billion miles, the region experienced zero smog alerts in 2000, down from 118 days in 1975 (CARB 2004). While the situation has improved considerably across the United States, the situation has worsened in many parts of the world. A 2001 joint study by the World Health Organization (WHO) and the United Nations Development Program (UNDP) analyzing air quality in China estimated there were “376 000

### Could the United States meet the Kyoto targets?

United States ratification of the Kyoto Protocol would have required the United States to reduce emissions 7% below 1990 levels by 2008 to 2012. What often is overlooked is that emissions have grown substantially since 1990 and that meeting the US obligation would require the United States to reduce projected emissions by somewhere around 30% by 2010. Without buying emission rights from other countries, meeting the Kyoto targets would have required fundamental changes in the way energy is consumed in the United States. The following example is indicative of the level of effort that would have been required for the United States to meet its Kyoto obligations.

United States CO<sub>2</sub> emissions totaled 4936 MtCO<sub>2</sub> in 1990. US emissions are projected at 6443 MtCO<sub>2</sub> in 2010. Therefore, in order to meet its Kyoto obligations solely through domestic action, the United States would need to reduce projected 2010 emissions by 29%, to 4591 MtCO<sub>2</sub>. Without reducing GDP growth, the two general options for meeting this obligation would be to alter the basic fuel mix or to increase the overall efficiency of energy use in the various sectors (energy intensities).

The following analysis, which uses the United States Energy and Greenhouse Gas Model, created at Sandia National Labs, shows how the United States could meet this obligation through fuel switching in the electricity sector alone, Figure 4.8. While in reality the United States would spread the reductions across all sectors, this example illustrates the magnitude of what it would take for the United States to meet its Kyoto obligation. Specifically, this example suggests that reducing emissions to 1990 levels by 2010 would require cutting coal's share from 52 to 3%, oil's share from 3 to 0%, and natural gas' share from 14 to 11%. In this example, nuclear's share almost doubles (42%) and the share of renewables other than hydro increases from about 2 to 35%.

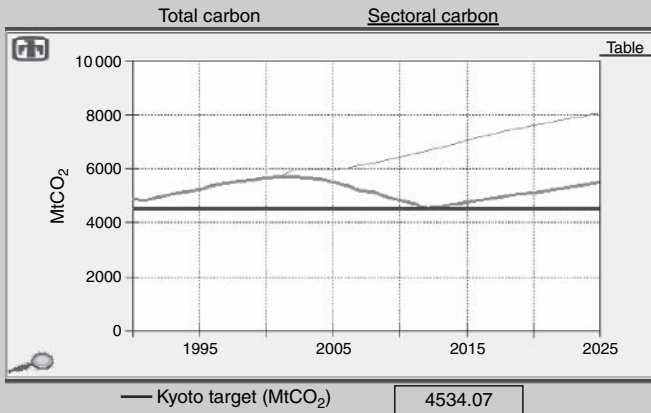


Figure 4.8 Meeting US Kyoto obligations through fuel switching in the electricity sector.

excess deaths” in 28 cities (out of 668) attributable to outdoor levels of sulfur dioxide between 1990 and 1998. The same report estimated an annual economic loss of \$10.3–\$19.3 billion due to this excess mortality.

These everyday pollutants include carbon monoxide (CO), nitrous oxides, sulfur dioxide, particulate matter, volatile organic compounds, and ozone. Like CO<sub>2</sub>, these emissions are measured in terms of parts per million.

#### *Local and regional pollutants: sources and effects*

Figure 4.9 illustrates the total emissions of several pollutants in the United States in 2001 and the responsible economic sectors. The significance of the transportation sector is readily apparent.

Carbon monoxide, often referred to as the silent, deadly killer, is a colorless, odorless gas. The CO is the byproduct of the incomplete combustion of fossil fuels. When people are exposed to high concentrations of the gas, they suffer from decreased oxygen in the blood due to CO out-competing oxygen for hemoglobin. This causes side effects such as visual impairment, dizziness, and headaches. The American Red Cross (ARC) (2004) reports that several thousand people in the United States each year go to the hospital with CO poisoning. At very high levels it can result in death. The Consumer Product Safety Commission reports

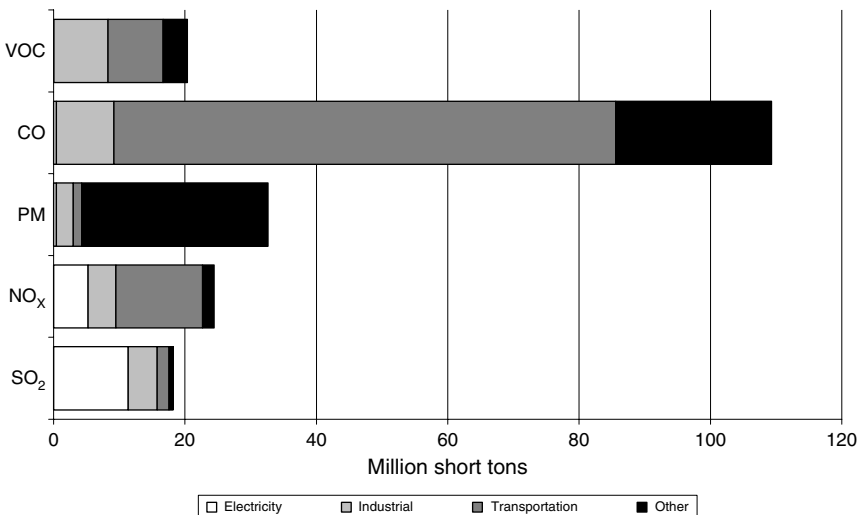
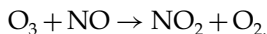
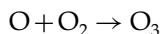
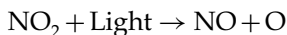


Figure 4.9. United States pollutant emissions by sector, 2001.  
(Source: EPA, 2003b).

that “every year over 200 people in the United States die from CO produced from fuel-burning appliances” (ARC 2004). Carbon monoxide is the most prevalent of urban air pollutants in the United States, with emissions totaling just under 110 million short tons each year (EPA 2003b). Approximately 70% of total CO emissions originate from the transportation sector.

Volatile organic compounds (VOC) consist of hydrocarbon emissions, most of which occur naturally. However, some VOC emissions are a result of the evaporation of hydrocarbons such as gasoline. VOCs react with sunlight, in much the same fashion as nitrous oxides ( $\text{NO}_x$ ), to create ground-level ozone (EPA 1995).

In the upper atmosphere, ozone ( $\text{O}_3$ ) blocks harmful UV radiation. At the ground level, however,  $\text{O}_3$  is hazardous to our health. It is not emitted directly into the atmosphere through the consumption of energy. Rather, it is created by atmospheric reactions with nitrogen oxides and hydrocarbons, in particular, VOCs. In the absence of VOCs in the atmosphere, the amount of nitrogen dioxide ( $\text{NO}_2$ ) and  $\text{O}_3$  in the lower atmosphere are kept in check:

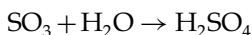
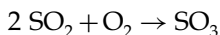


When exposed to sunlight,  $\text{NO}_2$  breaks down to nitric oxide (NO) and oxygen (O). The O reacts with  $\text{O}_2$  to form ozone. This ozone then reacts with the NO again to form  $\text{NO}_2$  and  $\text{O}_2$ . With the addition of VOCs from the incomplete combustion of fossil fuels, the VOCs react with NO in the air to form the  $\text{NO}_2$  that reacts with light to create smog. Ground-level ozone, one of the primary components of smog, is a major lung irritant. The EPA reports cities with high concentrations of ground-level ozone have increased hospital admissions for respiratory distress, which can cause permanent lung damage. In addition to the adverse health effects, ground-level ozone is responsible for approximately \$1-2 billion per year in agricultural crop damage (EPA 1995).

Nitrous oxides are highly reactive gases that form during the high temperature combustion of fossil fuels through the oxidation of nitrogen in the air. As outlined earlier, the reactivity of  $\text{NO}_x$  also makes it a major player in creating ground-level ozone, or smog. There are both health and environmental effects from the emission of  $\text{NO}_x$ . Health consequences include decreased resistance to respiratory infections, especially among children. On the environmental side, increased ozone that

results from emissions of  $\text{NO}_x$  leads to the eutrophication – increase of nutrients and subsequent decrease of oxygen – of coastal waters, harming fish and plant life. Increased  $\text{NO}_x$  is also partly responsible for acid rain. Acid rain is caused by the reactions between certain compounds, primarily  $\text{NO}_x$  and  $\text{SO}_2$ , with oxygen, water, and other chemicals in the atmosphere. It results in the acidification of our water and soil. The acidification of lakes and streams decreases the viability of aquatic life, while the acidification of soil harms plant life. The transportation sector is the primary polluter of  $\text{NO}_x$ , comprising 54% of total emissions (Figure 4.9) (EPA 2003a). Electricity and the industrial sector of the economy comprise 22% and 17%, respectively.

Sulfur dioxide is the other primary contributor to acid rain. Sulfuric acid ( $\text{H}_2\text{SO}_4$ ) is formed when sulfur dioxide reacts with oxygen and water:



Sulfur dioxide is a result of the combustion of fuels that contain sulfur, primarily coal and oil. Some coal has sulfur contents as high as 6% in the United States and 8% in China. Because of restrictions on sulfur dioxide emissions in the United States, most utilities now favor Western US coal, which is much lower in sulfur content than most Eastern coal. High concentrations of  $\text{SO}_2$  have many of the similar effects of other pollutants, including increased respiratory problems and the aggravation of cardiovascular illnesses. Electricity generation is responsible for over 60% of  $\text{SO}_2$  emissions in the United States.

Acid rain has resulted in the widespread acidification of lakes and forests around the world. The areas most sensitive to acid rain are those without limestone deposits, such as the Adirondack region of New York State. The effect of acid rain is species-specific; many species cannot adapt to lowered pH environments. Most fish species, for example, cannot survive in water with pH levels below 5.0. A detailed survey of 1469 Adirondack lakes and ponds in the mid-1980s showed that 352 lakes or ponds had pH values of 5.0 or less. In 346 of the identified lakes and ponds, no fish were found (Jenkins 2005).

Acid rain also damages structures, especially those built of marble. The United States Geologic Association (USGS) notes that stone “weathers as part of the normal geologic cycle through natural chemical, physical, and biological processes when it is exposed to the environment” (McGee 2006). Acid rain and other pollutants speed up this process and it results in the premature aging of historical buildings and statues. The

USGS mentions the marble columns of the Jefferson Memorial as an example of this process. Exposed marble in the Memorial has developed a “rough sugary texture” as “the edges dissolve in the rain water” (McGee 2006).

Finally, particulate matter (PM), or the solid and liquid particles that are released into the atmosphere, comes from both the actual emissions of particulates and the reaction between atmospheric molecules and  $\text{SO}_2$  or  $\text{NO}_x$ . Particulate matter can be divided based on the size of the particle. Health effects include respiratory distress as well as cancer and permanent lung damage. Fine particulate matter (<2.5 microns in size, PM 2.5) is a major cause of reduced visibility, or haze, in many parts of the country. The EPA notes visibility in several of our nation’s national parks and wilderness areas has been negatively affected by high particulate levels in the air. Particulate emissions that are not the result of other pollutants or natural causes come primarily from the industrial sector (EPA 1995).

#### *Pollutant regulations and trends in the United States*

The recognition of the negative health and environmental effects of air pollution in the United States led to the passage of the Clean Air Act (CAA) in 1970. The National Ambient Air Quality Standards (NAAQS) were created by the CAA and have been quite successful in reducing emissions. Table 4.2 summarizes the current NAAQS. Primary standards are intended to represent emission levels that are safe for most people, while secondary standards represent those necessary to protect the environment.

Under the regulations established by the CAA, atmospheric concentrations of these six principal pollutants have decreased overall. Emissions of CO and  $\text{NO}_x$  from vehicles have decreased by 96%.

For stationary sources such as power plants, environmental regulations in the United States and elsewhere require plants be built using “Best Available Control Technologies” (BACT). In the United States, these regulations control  $\text{SO}_2$ ,  $\text{NO}_x$ , and particulate emissions. However, holding older plants to the same standards often is much more difficult and expensive. A plant built in 1960 to burn coal, for example, may be very expensive to retrofit with advanced emission control technologies, such as scrubbers for  $\text{SO}_2$ .

To deal with emissions from older plants, the CAA Amendments of 1990 set overall limits on the amounts of  $\text{SO}_2$  and  $\text{NO}_x$  from stationary sources, but established an emission allowance scheme that allows plants to buy and sell pollution allowances. The goal is to minimize the cost of compliance while still meeting overall goals.

Table 4.2. National ambient air quality standards

Pollutant	Primary standard	Averaging time	Secondary standard
Carbon monoxide	9 ppm (10 mg/m <sup>3</sup> )	8-h	None
	35 ppm (40 mg/m <sup>3</sup> )	1-h	None
Lead	1.5 µg/m <sup>3</sup>	Quarterly average	Same as primary
Nitrogen dioxide	0.053 ppm (100 µg/m <sup>3</sup> )	Annual (Arithmetic mean)	Same as primary
Particulate matter (PM <sub>10</sub> )	50 µg/m <sup>3</sup>	Annual (Arithmetic mean)	Same as primary
	150 µg/m <sup>3</sup>	24-h	
Particulate matter (PM <sub>2.5</sub> )	15 µg/m <sup>3</sup>	Annual (Arithmetic mean)	Same as primary
	65 µg/m <sup>3</sup>	24-h	
Ozone	0.08 ppm	8-h	Same as primary
	0.12 ppm	1-h	Same as primary
Sulfur oxides	0.03 ppm	Annual (Arithmetic mean)	-----
	0.14 ppm	24-h	-----
	-----	3-h	0.5 ppm (1300 µg/m <sup>3</sup> )

Source: EPA (2004).

Specifically, the US Acid Rain Program is designed to reduce the emissions of SO<sub>2</sub> by 2 million tons and NO<sub>x</sub> by 2 million tons by 2010. The program has proved to be wildly successful. Coal plants that find it easier to install scrubbers or purchase lower sulfur coal are able to sell their "allowances" to other companies faced with more expensive means of reducing emissions. The rules force each utility that consumes coal to consider the cost of its sulfur emissions as part of its overall goal of minimizing production costs. The environment is the clear winner. Under the program, SO<sub>2</sub> emissions from large utilities will decrease from 30 million tons per year in 1990 to 8.95 million tons by 2010 (EPA 1999).

In addition to the federal Acid Rain Program, states are given a great deal of responsibility in mitigating other emissions, such as smog. Pollution limits are set according to the severity of the problem within certain areas of the country. Nowhere is this more obvious than in the transportation sector, where vehicular and fuel requirements vary considerably on a state-to-state basis.

Pollution controls on vehicles initially were established in 1970. Vehicle controls are one of three methods used to reduce emissions from mobile sources. Inspection and maintenance of the vehicles, and cleaner burning fuels such as oxygenated fuels, also are used.

The regulations on vehicles long have been mired in controversy. Automobile manufacturers argue that emissions standards and maintenance and inspection requirements sometimes are technically unfeasible or financially burdensome. In 1970, for example, standards were passed requiring a 90% decrease in vehicular emissions by 1980. The effective date later was moved up to 1975 due to increased knowledge of the harms of urban air pollution. Citing technical infeasibility, Lee Iacocca, the Executive Vice President of Ford Motor Company in 1970, went so far as to say that the environmental regulations “could prevent continued production of automobiles after January 1, 1975” (Business Week 1970). At the same time, while also arguing against the bill, General Motors (GM) introduced the use of the catalytic converter into the internal combustion engine vehicle, proving despite its argument that the environmental regulations were in fact technically feasible.

Eban S. Goodstein points out that, historically, initial estimates of the cost of environmental regulations have been significantly higher than actual costs (Goodstein 1999). Goodstein (1999) provides several examples. The cost of reducing the emissions of CFCs in automobile air conditioners was estimated to be \$650–1200 per new vehicle. However, the actual abatement cost is only \$40–400 per vehicle, an overestimation of 63–2900%. Other examples include sulfur dioxide, overestimated by 100–300%, and benzene, estimated to cost \$350 000 dollars per plant and actually costing nothing. Despite dissent from automakers and electricity generators, total emissions have decreased since the institution of the CAA (Table 4.3).

Overall, there is a downward trend in urban air pollution in the United States. However, the EPA reports that there are still 126 million people in the United States living in non-attainment areas where emission levels of at least one of the pollutants included in the CAA exceed the NAAQS (EPA 2003a). The EPA further reports that in the 263 metropolitan areas examined, 34 had upward trends in air

Table 4.3. Percent decrease in pollutants, 1980–1999

	Percent decrease in emissions (1983–2002)
Carbon monoxide	41
Lead	93
Nitrogen oxide	15
PM <sub>10</sub>	34
Volatile organic compounds	40
Sulfur dioxide	33

Source: EPA (2003a.)

pollution. Most of those areas exceeded the national standard for ozone measured over an 8-h period (EPA 2001). The Air Quality Index (AQI) is a measure of the total air quality based on EPA regulations. A value over 100 indicates air quality worse than the standard. In southern California, the number of days with an AQI above 100 decreased 62% between 1990 and 1999. However, other major cities across the United States saw a 25% increase in days with an AQI exceeding 100 (EPA 2001).

Several states have mandated the use of alternative fuels or set their own emission standards. California, where the car is king, in recent years has passed the toughest standards in the United States. Manufacturers of cars must ensure that a certain percentage of their vehicles sold in California meet the zero emission criteria. Specifically, this regulation requires that 10% of all light-duty passenger vehicles, model years 2005 to 2008, meet its zero emissions vehicle (ZEV) mandate. This percentage increases incrementally to 16% by 2018. Light-duty trucks also are covered by the requirement, starting with the 2007 model year.

Companies can meet the ZEV mandate in one of two ways. The first method includes a mixture of pure ZEVs and super ultra low emission vehicles (SULEV): 2% pure ZEVs, which are vehicles with no tailpipe emissions, such as electric vehicles; 6% partial zero emission vehicles (PZEV), which are 90% cleaner than the average new car and have near zero evaporative emissions; and 2% advanced technology PZEVs (AT-PZEVs), which in addition to low emissions, incorporate some alternative fuel technology, such as hybrid technologies. The second method for meeting the mandate, added in 2003, allows manufacturers to meet the requirement by selling a sales-weighted percentage of 250 fuel cell vehicles by 2008.<sup>5</sup> The quantity of fuel cell vehicles increases to 2500 from 2009 to 2011, 25 000 from 2012 to 2014, and 50 000 from 2015 to 2017. Manufacturers may substitute battery electric vehicles for up to one-half of their fuel cell component. In addition to the fuel cell vehicles, they must produce 4% AT-PZEVs and 6% PZEVs.<sup>6</sup>

Whether the California ZEV program will meet its goals is unclear. The initial compliance dates were rolled back in 2003 after the failure of pilot electric vehicle programs made it clear that manufacturers could not meet the targets. Manufacturers such as GM had introduced electric vehicles in the last decade precisely because of the California mandate. While electric vehicles were popular among customers who leased them, manufacturer support was short-lived. Both Ford and GM

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<sup>5</sup> This means that a manufacturer with 10% of the market in California would have to sell 25 fuel cell vehicles.

<sup>6</sup> Complete details of the CA ZEV mandate are available at: [www.arb.ca.gov](http://www.arb.ca.gov) (News Release 2003).

ended the pilot programs at the end of the signed leases, and required all customers to return their leased vehicles, regardless of whether the customer wanted to extend the lease. Two oft-cited reasons for the failure of the electric vehicle pilot program in California is the battery recharge time of up to 8 h and the limited driving range of 130 miles.

California has launched the California Hydrogen Highway initiative to establish a market for fuel cell vehicles. In announcing this initiative in 2004, Governor Arnold Schwarzenegger called for a public-private partnership to create hundreds of hydrogen fueling stations across the state. A key incentive, according to Schwarzenegger, is health related: "These vehicles produce no emissions and no smog. They will clean the air and get rid of the smog that is hanging over our cities, and reduce the health problems caused by our pollution" (Schwarzenegger 2004).

Obstacles to the California vision clearly exist. But this initiative illustrates how governments are using technology mandates or other regulatory means to counter local air pollution. Overall, these regulations have been wildly successful. As the California Air Resources Board notes, every vehicle meeting the California PZEV standard "emits only two pounds or less of hydrocarbons when driven 100 000 miles" compared to the 2000 pounds of hydrocarbons that were emitted by the average new car in 1965 ([www.driveclean.ca.gov](http://www.driveclean.ca.gov)).

While trends in reducing air pollution in the United States are positive, progress is mixed in other countries, particularly in many developing countries. As countries develop, air quality often is ignored until significant damage has been done. This occurred in the United States and in the United Kingdom, and is the case in countries such as China and India. As noted earlier, vehicle usage is booming in many countries such as China. In 2000, China had 16 million vehicles on the road; India had 50 million (Lawson et al. 2003). Kobos et al. (2003) predict vehicle levels of 125 million in China by 2025. The combined effects of growing vehicle use and widespread coal burning in China are causing extensive local and regional environmental concerns.

China already has taken many positive steps toward dealing with local and global air pollution issues. Gallagher (2006) provides an excellent summary of current air pollution problems in China. The increase in passenger vehicles is a huge contributor. During the summer months in Beijing, according to Gallagher, 92% of the CO, 94% of the hydrocarbon emissions, and 68% of the nitrogen oxide emissions are attributable to cars. While coal plays a larger role during winter months, the transportation sector remains the main contributor of these pollutants.

Recognizing the effect of its burgeoning transportation sector, in 2000 China enacted regulations requiring cars to meet the European Tier I emission standards and for all cars to meet the more stringent Tier

Table 4.4. Comparison of European, United States, and Chinese vehicular emission requirements

Country, year	CO	HC	NO <sub>x</sub>	CO <sub>2</sub>
Euro I, 1992	4.05	0.66	0.49	None
China, 2000	4.05	0.66	0.49	None
Euro II, 1994	3.28	0.34	0.25	None
China, 2004	3.28	0.34	0.25	None
Europe 1995 <sup>1</sup>				187
US Tier 1, current	2.6	0.16	0.37	None
Euro III, 2000	2.3	0.2	0.15	
Euro IV, 2005	1	0.1	0.08	
US Tier 2, 2007	1.3	0.01	0.04	None
Europe 2008 <sup>1</sup>				140

<sup>1</sup> This is a voluntary standard.

Source: Adapted from Gallagher (2006).

II standards by 2004. Vehicular air pollution standards for the United States, Europe, and China are summarized in Table 4.4. Gallagher (2006) notes that compliance with the regulations has been, at best, “inconsistent and problematic.” However, pollution-related issues are becoming widely recognized across China. It seems likely that China will continue to tighten regulations as quickly as possible.

The United States has made great strides in eliminating or greatly reducing the emissions of harmful urban air pollutants. Market-based programs have proved to be successful in reducing emissions from stationary sources such as power plants. Meanwhile, legislation such as the CAA has reduced emissions from mobile sources, largely through technical solutions. While legislative opponents criticized the high cost of implementation, the actual cost of emissions reductions turned out to be lower – sometimes significantly lower – than initial cost estimates. While local and regional air pollution in the United States has shown marked improvements, the situation is less clear in developing countries. Some countries, such as China, are confronting the issue with regulations modeled after European or United States standards. Whether these steps will be sufficient to avoid large increases in pollution-related illness and death is unclear. Clearly, part of the lure of hydrogen vehicles is that they represent the ultimate clean transportation option: zero tailpipe emissions, with performance at least as good as vehicles that exist today.

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Part III  
**On the Road to Hydrogen**

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# Chapter 5

## Progress towards a Hydrogen Future

Considerable excitement exists about hydrogen's potential. Is the talk about a hydrogen future more than just hype? Or are our leaders holding out the promise of hydrogen as an attempt to placate a public concerned about environmental and energy security? The answer is a bit of both. Hydrogen does offer significant hope that we are able to move away from our reliance on fossil fuels. At the same time, the hurdles are real and quite significant. Despite these obstacles, governments and companies worldwide have embraced the notion that hydrogen some day can be a significant part of our overall energy systems. Virtually every car company has programs aimed at commercializing fuel cells or engines that run on hydrogen. Outside the automotive sector, companies are pursuing stationary and mobile applications for fuel cells. The hope is for fuel cells to power a wide variety of applications, ranging from laptops, cell phones, and backup power systems, to home heating and power sources. Based on the number of companies seeking to capture various markets, the buzz is more than hype.

### Fuel Cell Cars

Tonight I'm proposing \$1.2 billion in research funding so that America can lead the world in developing clean, hydrogen-powered automobiles. With a new national commitment, our scientists and engineers will overcome obstacles to taking these cars from laboratory to showroom, so that the first car driven by a child born today could be powered by hydrogen, and pollution-free.

George W. Bush, State of the Union Address, 2003

By stacking several fuel cells, one can generate enough electricity to power a car or a bus. President Bush's vision is that fuel cell cars will be a viable option by 2015–2020. Getting there will require a huge effort

on the part of car companies, energy companies, and the government. Many companies, such as General Motors (GM), believe they are on track to sell a million vehicles per year by 2020. The engineer leading GM's fuel cell effort states that he has a 2009 deadline for resolving remaining technical hurdles and that he fully expects to meet that deadline (Fronk 2006).

Most of the early tests of fuel cells were done with buses, because the fuel cells can be stacked on top of the bus (Figure 5.1). Vehicle manufacturers have taken different approaches to commercializing fuel cell cars. Most car companies have at least one prototype fuel cell car, including Honda (Honda FCX), Ford (Ford Focus FCV and Ford P2000), DaimlerChrysler (NECAR and Mercedes F-Cell), Toyota (FCHV), and General Motors (HydroGen3, Sequel, and HyWire). In September 2005, DaimlerChrysler and Ford took over the fuel cell system division of Ballard Power Systems, Inc., the Canadian company responsible for providing fuel cells for their FCVs (ABC Auto News 2005). Rather than relying on Ballard fuel cells, GM, Honda, and Toyota are developing their own.

Each car company has slightly different ideas on fuel cell car design. Ford's strategy is to modify existing models. Ford's rationale is that consumers are more likely to adopt a new technology if it provides comparable service and is not radically different in appearance from their current vehicles. In other words, consumers are comfortable driving existing models and may not be willing to purchase vehicles that look radically different. They may be right. Sales of the Honda Insight,



Figure 5.1. Ballard buses.  
(Source: Fuelcells.org, 2006).

a futuristic-looking hybrid vehicle, have lagged well behind those with a more conventional look, such as the Honda Civic Hybrid and the Toyota Prius.

In 2005, Ford had two modified Ford Focus hydrogen fuel cell vehicles on the road – the Ford Focus FCV and the Focus FCV-Hybrid, which combines the hydrogen fuel cell with a nickel metal hydride (Ni-MH) battery to increase efficiency and performance. In the Focus FCV the hydrogen storage tank – which holds enough gas compressed to 3600 psi to allow for a vehicle range of only 100 miles – is located behind the passenger seat and takes up a significant portion of the trunk. Each car is powered with a 67 kilowatt (kW) (90 hp) Ballard Mark 900 proton exchange membrane (PEM) fuel cell. The car is quieter than a gasoline-powered Focus; the conventional engine noise is replaced with a distinctive electric motor whirr. The car is used mainly to demonstrate the viability of hydrogen to interested media, politicians, and attendees at various energy-related trade shows (Ford 2005a).

The Ford Focus FCV-Hybrid uses a slightly smaller electric motor (65 kW, 87 hp) powered by Ballard PEM fuel cell stacks combined with a Sanyo Ni-MH battery system. According to a Ford press release, “The FCV is hybridized with the addition of a nickel metal-hydride battery pack and a brake-by-wire electro-hydraulic series regenerative braking system” (Ford 2005b). Using hydrogen compressed to 5000 psi, the Focus FCV-Hybrid has a range of 160–200 miles, a significant improvement on the Focus FCV. As part of a seven-city, 30-car test program, Ford has delivered the FCV-Hybrid to cities in Michigan, California, and Canada (Ford 2005c).

In addition to the Focus, Ford has used the Ford Contour as a platform for the Ford P2000. Like the Focus FCV, the P2000 uses compressed hydrogen as the fuel source for Ballard PEM fuel cells and has a range of only 100 miles. Unlike the Focus, which is designed for production, the P2000 is built on a lightweight research platform. In addition to hydrogen fuel cells, Ford has two methanol fuel cell prototypes – the Ford Focus FC5 and the Mazda Premacy (Ford 2005d).

General Motor’s design track differs decidedly, from the use of proprietary fuel cells to the overall design. In 2002, GM introduced the Autonomy concept car, which is the first of its kind using fuel cell and by-wire technology. In 2003, GM expanded on this idea and introduced the first drivable concept car that utilizes both technologies: the HyWire, which resembles a futuristic vehicle (Figure 5.2). Whereas Ford’s strategy assumes consumers will drive fuel cell cars only if they look and feel similar to existing vehicles, GM’s philosophy is to change the way consumers view their cars. In the HyWire, all of the components – the fuel cells (200 stacked in series, 94 kW), the hydrogen storage (three



Figure 5.2. GM's HyWire Fuel Cell Vehicle.  
(Source: Fueleconomy.gov, 2006; General Motors, 2005c.)

5000 psi tanks), the computer module, and the electric motors – are located in what resembles an oversized skateboard. The chassis sits on top of this 11-inch thick “skateboard” and connects to it through a single portal, similar to a docking station for laptop computers. The entire chassis requires just 10 connections to the base. Theoretically, this approach could lead to the ultimate throwaway vehicle – keep the base and replace the chassis. Having the components in the base also frees up the interior design of the car (Figure 5.3). The engine block is gone



Figure 5.3. Inside view of GM's HyWire Vehicle.  
(Source: Fueleconomy.gov, 2006.)

from the front; in the HyWire prototype this is just a wide, open area. There is no “under the hood.” Also gone is the gas pedal. The driver controls speed from the steering wheel (General Motors 2003).

In addition to the futuristic Hywire and Autonomy concept cars, GM has two prototypes that resemble conventional vehicles – the HydroGen3 Fuel Cell Vehicle (General Motors 2005a), based on the Opel Zafira minivan, and the Sequel (Figure 5.4), which is about the size of a Cadillac SRX. General Motors has produced two versions of the HydroGen3 – liquefied and compressed gas. Both are powered by 200 fuel cells stacked in a series with a continuous output of 94 kW. The compressed gas model stores 3.1 kg of hydrogen in two carbon composite tanks compressed to 10 000 psi, allowing for a driving range of 170 miles. The liquefied model of the HydroGen3 uses vacuum-insulated stainless steel tanks to store 4.6 kg of hydrogen, allowing for a driving range of 250 miles. Partnering with Shell, GM has provided officials in Washington, DC, with a HydroGen3 fleet for a 2-year test program. In addition, the HydroGen3 is being tested by FedEx in Japan for a year and in Berlin (General Motors 2005a).

In 2005 GM unveiled the newest fuel cell by-wire prototype, the Sequel. The Sequel improves upon previous fuel cell technologies by providing a driving range up to 300 miles using hydrogen compressed to 10 000 psi and by accelerating to 60 mph in only 10 s, compared to the 12- to 16-s acceleration in current generation FCVs. Larry Burns, Vice President of Research, Development and Planning at GM, says that, “with Sequel virtually everything is packaged in an 11-inch ‘skateboard’ chassis, building on what we first showed the world in the Autonomy and HyWire. Sequel points to a vehicle that, in the future, will be better in nearly every way – quicker, surer-footed, easier to handle, easier to build, better looking, safer and only emits water vapor” (General Motors 2005b).

Toyota uses a technology that combines fuel cells with a nickel-metal hydride battery to gain increased efficiency and driving range.



Figure 5.4. GM Sequel.  
(Source: General Motors, 2005c).

Toyota's prototype, the FCHV, is based on the Toyota Highlander and has been refined several times since being introduced in 2001. The electricity produced in the fuel cell is used to power the electric engine and charge the battery. The Toyota FCHV, a refinement on their FCHV-4 model, was introduced to the market in 2002 with two FCHVs leased in California and another two leased in Japan, where the vehicle underwent 18 months of real-world testing (Toyota 2005a). The FCHV has four 5000 psi fuel tanks and a cruising distance of over 150 miles.

In addition to the FCHV, Toyota is working on the FCHV-5, which will utilize a reformer to produce hydrogen (Toyota 2006). The input for the reformer will be Toyota's Clean Hydrocarbon Fuel (CHF), which Toyota is marketing as a next-generation liquid fuel. CHF is produced from crude oil, natural gas, or coal, and has a low-sulfur content. According to Toyota, the added benefit of this approach is that the CHF is a flexible fuel – it can also fuel gasoline-powered cars and be pumped from existing pumps. Toyota also has worked with Hino Motors, Ltd., to develop the FCHV-BUS1, a low-floor city bus powered by a hybrid fuel cell battery system similar to the FCHV.

While Toyota has invested a great deal of research into developing FCHV prototypes, the company believes that for the foreseeable future, the "hybrid technology is key to creating highly efficient vehicles" (Kawai 2003). According to Taiyo Kawai (Kawai 2003), General Manager of the Fuel Cell System Engineering Division at Toyota, Toyota's strategy is to continue developing and marketing the hybrid vehicle. Toyota's hybrids have both gasoline and electric engines. Energy captured from regenerative braking and from excess energy produced by the gasoline engine during periods of non-acceleration is stored in onboard batteries and is then used to power the electric engine to supplement the gasoline engine during acceleration. Additional energy is saved by turning the engines off whenever the vehicle stops. One of the main benefits of the Toyota strategy is that it gives Toyota valuable experience with electric drive trains in vehicles. Once fuel cells become commercially viable, Toyota will be ready to simply replace the gasoline engine with the fuel cell.

In 1994, DaimlerChrysler introduced the world's first fuel cell research vehicle, the Mercedes-Benz NECAR 1. Since then, they have produced 20 research vehicles and prototypes (DaimlerChrysler 2004). The NECAR has since evolved into the Mercedes-Benz F-Cell A-Class. The F-Cell stores enough hydrogen to power the 65 kW engine for a driving range of approximately 100 miles in two 5000 psi storage tanks. In 2003 DaimlerChrysler began practical testing of 60 F-Cells in Europe, the United States, Japan, and Singapore. In addition to the F-Cell, Mercedes is testing 30 fuel cell buses, the Citaro F-Cell, in Europe, and an

additional three in Perth Australia, and DaimlerChrysler has plans to provide three to Beijing (DaimlerChrysler 2004). The Citaro F-Cell has a range of about 120 miles, and the 200 kW fuel cell-powered engines and hydrogen storage tanks (5000 psi) are stored in the roof of the bus. In 2001, the Mercedes-Benz Sprinter van made its debut for use in Germany's commercial sector. Used for 2 years by the Hamburg-based Hermes Versand, a parcel delivery service, the Sprinter has shown great promise and reliability including the ability to be refueled in only slightly longer time than a conventional diesel vehicle. In August 2004 the Dodge Sprinter, based on the Mercedes Sprinter, was introduced in United States markets for use by United Parcel Service (Figure 5.5) (Mercedes-Benz International 2005a).

In October 2005, Mercedes-Benz unveiled its newest FCV, the F 600 HYGENIUS (Figure 5.6). The efficiency of the 85 kW (115 hp) fuel cell engine hybridized with a lithium-ion battery allows for a driving range of more than 240 miles. Dr. Thomas Weber, who is head of research and technology at DaimlerChrysler and responsible for development at the Mercedes Car Group, commented that "this means that we have taken a big step toward the marketability of the fuel cell, engine and our target time is between 2012 and 2015." In addition to the increased driving range, the F 600 HYGENIUS improves upon the ability to start the engine in the cold, a problem with earlier FCVs (Mercedes-Benz International 2005b).

In 1999 Honda introduced two prototype vehicles - the FCX-V1, powered by a hydrogen fuel cell, and the FCX-V2, powered by a methanol fuel cell. For the FCX-V1, Honda relied on fuel cell stacks manufactured by Ballard. The methanol fuel cell stacks for the FCX-V2



Figure 5.5. Dodge Sprinter UPS van.  
(Source: Mercedes-Benz International, 2005a).



Figure 5.6. Mercedes-Benz F 600 HYGENIUS.  
(Source: Mercedes-Benz International, 2005b).

were manufactured by Honda. The following year Honda unveiled the FCX-V3, which is powered by both Ballard- and Honda-manufactured hydrogen fuel cells. The FCX-V3 used hydrogen compressed to 3700 psi and had a vehicle range of just over 100 miles (Honda Worldwide 2005a).

Honda rapidly continues to introduce improved versions of the FCX, with increased power and range (Figure 5.7). With hydrogen compressed to 5000 psi, the FCX can travel as far as 250 miles using its 80 kW electric motor powered by a Honda-manufactured PEM fuel cell stack (Honda Worldwide 2005b). The Honda FC Stack, released in



Figure 5.7. Honda FCX at the Geneva Motor Show, 2005.

October 2003, is capable of operating in temperatures as low as  $-20^{\circ}\text{C}$ . In December 2002 Honda began practical testing of the FCX in the United States and Japan, and in 2004 began testing the new Honda FC stack. In addition to official road tests in New York, California, and Tokyo, Honda is leasing the FCX to Iwatani International Corporation (Honda Worldwide 2005a). In June 2005, Honda became the first car manufacturer to lease a FCV to an individual family (Honda Worldwide 2005c).

Some believe that today's hybrids already may deliver, in terms of fuel efficiency, what the fuel cell promises. The second-generation Toyota Prius, introduced in 2004, has an EPA efficiency rating of 60 mpg in the city and 52 in rural driving, a remarkable improvement over the first-generation Prius, which had an EPA rating of 52 mpg in the city and 45 in rural driving. This new Prius is also larger, classified as a mid-size rather than a sub-compact. It accelerates from 0 to 60 mpg in 10 s compared to 12 s for the older version. The onboard battery has decreased from 76 kg in 1998 to 45 kg in 2004. Toyota's strategy is to offer hybrid versions of all its vehicles, including the Lexus RX and the popular Toyota Camry (Hermace 2003). Despite lofty achievements with the hybrid, Toyota acknowledges the rationale for eventually moving to FCVs. The company estimates the well-to-wheel efficiency of the hybrid vehicle is around 29%, compared to about 16% for the internal combustion engine vehicle. Toyota predicts that a hybridized fuel cell vehicle (FCHV) will be able to achieve an overall efficiency of 42%, which is 1.5 times better than gasoline hybrids and three times the ICE vehicle (Kawai 2003).

### **Other Hydrogen Vehicles**

In addition to FCVs, such major car manufacturers as BMW and Ford are focusing their efforts on alternative hydrogen-powered vehicles, including the hydrogen internal combustion vehicle. Ford's Model U Concept runs on an internal combustion engine (ICE) optimized to burn hydrogen and based on the 2.3-liter I-4 engine used in the Ford Ranger. The company claims "it can reach an overall efficiency of 38%, which is approximately 25% better than a gasoline engine (Ford 2006)." The Model U provides the same power as a gasoline ICE while providing efficiency and environmental benefits. In addition to the Model U, Ford has introduced the E-450, its first hydrogen-powered shuttle bus. The bus uses 26 gallons of hydrogen compressed to 5000 psi in a modified Triton V-10 ICE, yielding a driving range of 150 miles. The E-450 was to hit the road in Florida and Texas in 2006 (PEB 2005).

In addition to its own hydrogen ICE bus, Ford worked with ISE Corporation to create the first bus using a hybridized hydrogen internal

combustion engine (HHICE). According to the ISE Corporation (2004), "ISE's HHICE drive system is the first commercially-available transit bus drive system that uses hydrogen fuel. The vehicle's 6.8-liter Ford engine, modified by Ford to burn hydrogen, is used to run a Siemens generator, which supplies up to 150 kW of electric power. The Ford engine-Siemens generator performs an onboard electrical power generation function similar to that of a fuel cell."

BMW is experimenting with dual hydrogen/gasoline vehicles. Its 745h features a 4.4-liter V-8 engine that can run on either hydrogen or gasoline. According to the company, "Running on hydrogen, the 745h produces 184 horsepower and can achieve a top speed of 133 mph. The cruising range is 190 miles. Added to the 400-mile range of the normal fuel tank, the 745h can go 600 miles between fill-ups" (BMWWorld 2004). The 745h uses a small fuel cell to power the electrical needs of the vehicle. This auxiliary power unit is fueled directly from the onboard hydrogen tank. As an added benefit, the power unit works even when the car is off, making the car a possible mobile power source. This type of innovation might differentiate hydrogen cars from traditional cars and help speed market penetration.

### **Portable Applications**

There is considerable interest in the viability of fuel cells as power sources. While most FCVs rely on PEM fuel cells, portable applications are split between the PEM and direct methanol fuel cells (DMFC). Portable fuel cell applications are those under 1.5kW and include such products as batteries for electronics and generators.

Many companies involved in the development of portable fuel cell applications are targeting military use, with future adaptations aimed at consumers. One source talks about the potential this way: "The U.S. Marines used approximately 3000 batteries per day during the first two weeks of Operation Iraqi Freedom, implying a usage rate of over 4 million units per year for the military overall. In addition, the BA-5590 battery currently used by the military is heavy, weighing more than 2.5 lbs" (Voller Energy 2005a). These batteries also need recharging by generators, which can be detected by enemy forces.

In recent years, Japanese companies have led the way in creating fuel cells suitable for electronics. Casio is developing a methanol reformate fuel cell to use in laptop computers and digital cameras. While the fuel cell is only about the size of a typical rechargeable battery, it lasts four times longer. According to Baker (2005a), Fujitsu Laboratories (Japan) and NTT DoCoMo have developed a prototype fuel cell for mobile

phone batteries, with a target market introduction date of 2006. The prototype uses a thumb-sized cartridge containing  $18\text{Cm}^3$  of methanol at a concentration of 30%. Baker notes the companies “are also developing a fuel cell battery that will slot into a mobile phone, replacing existing lithium-ion batteries.” Also in Japan, Hitachi has a fuel cell-powered prototype personal digital assistant (PDA), the Nature Viewer, which was unveiled in 2004. Hitachi also has introduced prototypes of mobile phones, which it plans to commercialize in 2007, and laptop computers, slated for sale in 2006.

In the United States, the California-based Jadoo Power Systems has developed the NAB II (Figure 5.8), a fuel cell powered by hydrogen stored as a solid in metal hydrides, for use as a camera battery. The hydrogen cartridges are available in two sizes, 130 Wh and 275 Wh (providing 4 or 8 h of power [Baker 2005a]), which can be refilled in under 1 h or 2 h, respectively, using Jadoo’s Fillpoint (Jadoo Power Systems 2005).

Medis Technologies of Israel, has created a disposable auxiliary power unit, the Power Pack, for use on a wide range of electronics including cell phones, PDAs, digital cameras, MP3 players, and other small electronics. The Power Pack has a significantly longer operating time than traditional batteries. For example, when used for a cell phone, the



Figure 5.8. Jadoo NAB II portable fuel cell.  
Source: Jadoo Power Systems, 2005.

Power Pack provides enough power for 20 h of talk time, five to six times as much as a battery. The Power Pack allows a device to run while charging the battery. Medis, which is marketing portable fuel cells to the military, reports: "Our refuelable Power Pack is being developed to provide auxiliary power to a ruggedized PDA being developed by General Dynamics to meet military specifications. At present, the PDA is charged by a battery sleeve with eight lithium manganese oxide batteries. For a 72-h mission, always on, the present system would require the military team to carry about 140 batteries costing approximately \$450. Our refuelable Power Pack is expected to provide approximately 72 h of operating time with the use of only four or five refueling cartridges, making it lighter and less expensive than the present system" (Medis Technologies 2005).

The US company Millennium Cell has developed a prototype fuel cell used to power an IBM ThinkPad. Currently, the prototype runs for only 3 h, but Millennium aims to increase the running time to 8 h. The company expects the fuel cell to cost approximately \$150, about the same price as a standard laptop battery. NEC, a Japanese company, has multiple versions of its DMFC laptop prototype. The most current model, released in October 2005, is 20% smaller than the 2004 model and has a power output density of 70 milliwatts (mW) per square centimeter, a 40% improvement on the previous model. One 250 Cm<sup>3</sup> methanol cartridge can power the laptop for 10 h. The company plans to commercialize the laptop in 2007.

In Korea, Samsung Advanced Institute of Technology is developing butane-powered fuel cells to act as power supplies for small electronics. As of 2006, the fuel cell produces a maximum of 100 watts (W) of electricity. The 220-gram (g) liquefied butane cartridge can power a laptop for more than 20 h. Samsung plans to commercialize the butane fuel cell in 2007 and increase the maximum power output to 300 W. In a partnership with IBM, Sanyo produced a DMFC for an IBM ThinkPad laptop computer. The prototype, introduced in April 2005, provides up to 8 h of power and works with a battery in a hybrid system.

The German company Smart Fuel Cell (SFC) is developing auxiliary power sources for use in small electronic devices. Notes Baker (2005a), the "portable SFC C20 system with a Li-polymer hybrid battery is designed as an external energy supply for mobile and wireless uses. With one single M500 fuel cartridge, the fuel cell generates more than 440 wathours (Wh) of net energy output." The fuel cartridge weighs 470 g, and has an energy density of over 930 Wh/kg. Future versions of this technology will power laptops, cameras, and electric tools.

Says Fumio Ueno, Toshiba's fuel cell technology chief: "We're starting with as small an application as we can and keeping costs low. . . . We

think it's better to start that way and grow into larger applications" (Dvorak 2005). Toshiba has developed what is considered to be the smallest DMFC in production for use in portable electronic devices. The company has developed two prototypes – a 100 mW unit and a larger 300 mW unit. The smaller of the two prototypes can power a small flash-based audio player for about 35 h off only 3.5 milliliters (ml) of methanol. The larger unit can power a larger audio player for 60 h with a 10 ml charge. Toshiba also has introduced a prototype fuel cell to power a PORTAGE M300 laptop computer. The current prototype (Figure 5.9) can power the laptop for approximately 10 h on one charge, but it is still too large and heavy for commercialization. Dvorak (2005) reports that both Toshiba and Hitachi Ltd. are developing cellphones for Japanese mobile carrier KDDI Corp that run on or are recharged by fuel cells.

Another company that is using the military as a first step to commercialization is UltraCell Corporation of the United States. Using a fuel cell based on the reformed methanol fuel cell technology, which converts concentrated methanol into pure hydrogen, UltraCell has developed the XX90, which provides up to 45 W of continuous power. The prototype, weighing only 1 kg, was developed for use in the military. UltraCell is now working to develop the UltraCell25 for use in commercial computing applications.

Finally, Voller Energy of the United Kingdom is focusing its efforts on developing fuel cell systems for leisure and military use. The Voller Energy VE100 V3 (Figure 5.10), is a portable generator available in both industrial and military versions. The 9-kilogram, portable, 100-watt battery re-charger and generator uses a water-cooled PEM fuel cell stack. The hydrogen is stored in a Voller Energy Hydrogen Canister, which dissolves the hydrogen in a metal salt, allowing for a much

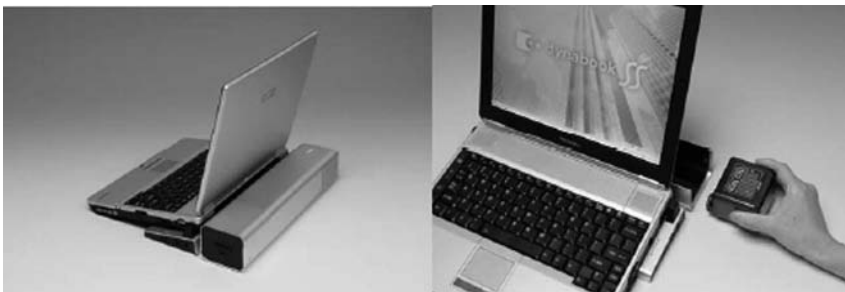


Figure 5.9. Toshiba DMFC laptop computer.  
(Source: Baker, 2005b).



Figure 5.10. Voller Energy VE100 V3.  
(Source: Fuelcells.org, 2006).

higher volumetric density and lower pressure than traditional compressed hydrogen canisters (only 150 psi). The addition of a lead acid battery allows the generator to provide a maximum power of 200 W for short periods of time. Each 250 nanolitres of hydrogen provides approximately 340 Wh of power generation (Voller Energy 2005b).

Angstrom Power, based in Canada, is developing portable fuel cells for use as battery replacements under 20 W. Angstrom currently is developing a small flashlight powered by a hydrogen fuel cell. The company's expectation is that in 2–5 years the product will cost 20–30% more than current batteries, but will provide four to 10 times the life. Antig, a Taiwanese company created in 2003, is working currently on developing a DMFC power source for laptop computers as well as a charger for mobile phones. Their 12 W prototype weighing 435 g was expected to enter the market in 2006 and become fully commercialized in 2008–2009.

Idatech Advanced Fuel Cell Solutions of the United States has developed a 250 W Portable Power System that can provide 4 h of backup power with 2 liters of a methanol and water mixture as fuel. The system uses a PEM fuel cell and includes a fuel processor in the module (Idatech 2005a). Idatech initially is marketing 1 kW Modular Fuel Cell Systems to the military. These systems are scalable and able to use a variety of fuel sources (Idatech 2005b).

Other companies developing portable fuel cell generators are Arcotronics, an Italian company that has developed a 1 kW system intended for outdoor use, and Asia Pacific Fuel Cell Technologies of Taiwan, which is working on fuel cell stacks and systems between 100 W and 12 kW. Aperion Energy of the United States also has developed the Independence 100, a 100 W PEM fuel cell system weighing only 45 pounds and designed for use as a power source for remote signaling, signs, and monitoring devices. Powered by hydrogen, it also can be used as a battery charger and is commercially available (Aperion Energy 2006a). Like several other companies involved in producing fuel cells for portable applications, Aperion also is developing small stationary fuel cell systems.

### **Stationary Applications**

Fuel cells are being developed for stationary use at either the small residential or commercial level or at the larger commercial level to provide a power source as well as supply backup electricity. In addition, much of this development uses excess heat from electricity production in combined heat and power (CHP) fuel cell systems. These stationary applications are being tested in real-world applications in hopes of marketing them in the near future.

#### *Small stationary applications*

Currently, more than 3000 stationary fuel cell units under 10 kW are installed globally. Much of this installed capacity is in Japan, followed by North America and Europe. The two primary uses for these small stationary fuel cell systems are residential power generation and uninterruptible power supply (UPS). Size for residential power supply units varies widely. The small systems, usually about 1 kW CHP systems, are used to provide base load electricity for 8 h a day and continuous hot water for a single-family home. These units are connected to the electric grid; peak and night-time demand are met by the grid. Larger 5 kW units, which are not always CHP systems, might be connected to the grid - but only a short period of peak power demand will not be met by the fuel cell system. These larger units also can be used to power multiple homes. More than half of these small stationary residential units are the small 1 kW type, mainly because these are most easily integrated into the current home heating model. Meanwhile, the UPS systems are generally in the 2–10 kW range (Adamson 2005).

While there are multiple options for fuel cell types, the only two types actively being pursued are the proton exchange membrane and

the solid oxide fuel cells (SOFC). The PEM fuel cells comprised approximately three-fourths of new developments in 2005 while SOFC made up the remaining quarter. Fuel choice for these fuel cell systems is also concentrated. Most residential units use natural gas, propane, and small amounts of liquefied petroleum gas (LPG) so that the existing infrastructure can be utilized. Meanwhile, most UPS systems use compressed hydrogen as their fuel source.

The Japanese government is especially active in promoting the use of small, 1 kW, stationary fuel cell systems. In 2005 The New Energy Foundation (NEF) announced a goal of installing 400 units with subsidies of up to 6 million yen per unit (60–75% of the total cost). In 2006 and 2007, the program plans to install 1000 and 5000 units, respectively, with NEF subsidies of up to 3 million yen in 2006 and 2 million yen in 2007. Costs were expected to fall below 1 million yen by the end of the 3-year program. Initially, seven Japanese corporations, mostly utility companies, were slated to receive the subsidies with fuel cells provided by Ebara Ballard and Toshiba Fuel Cell Power Systems (Adamson 2005).

In addition to the Independence 100, Aperion has two small stationary PEM fuel cell applications commercially available: the 1 kW Power Generation Module (PGM) and the Independence 500 500 W PEM fuel cell system. The Power Generation Module is intended as a backup power source and runs off compressed hydrogen. According to an Aperion brochure, “Aperion PGM features patented Modular Cartridge Technology from Avista Labs with Aperion power electronics and controls, making the system highly reliable and easy to operate and maintain. ‘Hot-swappable’ fuel cell cartridges can be replaced in seconds while the system continues to provide power to connected loads (Aperion Energy 2006b).” Meanwhile, the Independence 500 is designed specifically for battery charging.

In 2005 Ceramic Fuel Cells Limited of Australia began testing its small residential CHP units at commercial sites in Australia, New Zealand, Tasmania, and Germany. Their micro-CHP unit uses natural gas to fuel its 150 W sub-stacks of solid oxide fuel cells to produce 1 kW of electricity and a thermal output of 1 kW (CFC Ltd. 2006a). In addition to small CHP modules, Ceramic Fuel Cells Limited has developed a distributed generation product for residential and small commercial applications. The system is made up of sub-stacks of 150 W SOFC combined to create 2 kW of electricity output. These 2 kW units then can be combined to create larger, 5–6 kW output units, with a peak power of up to 10 kW. Either connected to the grid, or independent, these distributed generation systems can provide base load power or act as a UPS system. The option also exists to use the waste heat for cogeneration (CFC Ltd. 2006b).

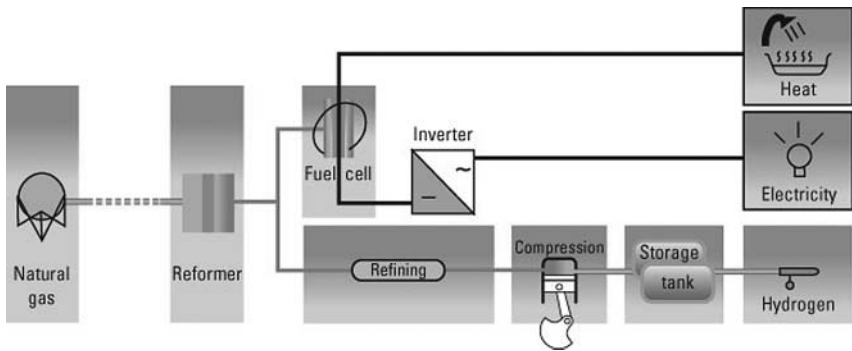


Figure 5.11. Honda Home Energy Station (HES II).  
(Source: Honda Worldwide, 2005d).

Also developing fuel cells for residential use is Honda. In addition to its production of FCVs, Honda is experimenting with a Home Energy Station (HES) that uses natural gas to produce hydrogen to be stored for use in FCVs and in a fuel cell to produce electricity and heat (Figure 5.11). In November 2004 Honda launched a test of the second-generation Home Energy Station, the HES II, at the Plug Power Inc. headquarters in New York. The HES II produces over 4 kW of electricity (Honda Worldwide 2005d).

ReliOn of the United States is one of the first fuel cell companies to commercialize its product. The I-1000 is a 1 kW backup PEM fuel cell power system that runs on compressed hydrogen. ReliOn currently has more than 550 kW of its technology installed globally. Their hot-swappable Modular Cartridge Technology<sup>1</sup> allows for increased reliability, ease of maintenance, and most importantly, scalability, which increases commercial potential (ReliOn 2006).

Ballard, a company known for developing fuel cells for vehicles, also is developing small stationary fuel cell systems for backup power generation as well as CHP. The AirGen is the world's first portable backup power generator specifically designed for indoor use. The 1 kW unit can provide power for up to 15 h off of one compressed hydrogen

<sup>1</sup>ReliOn describes the cartridge this way: "the PEM membranes are housed within an inexpensive plastic cartridge that is air-cooled and self-humidifying. There are no pumps or compressors to fail. Hydrogen enters one side of the cartridge, air the other. The only moving part is a high efficiency fan. If a cartridge fails, the system shunts around it and continues to operate as before. The system automatically bypasses the cartridge with the problem, and continues to provide power to the load. Cartridge replacement takes only a few seconds, and requires no tools (<http://www.relion-inc.com/difference.asp#>)."

storage canister. The PEM fuel cell unit can act as a portable generator or a standby uninterruptible power supply, providing immediate backup power and surge protection (Ballard Power Systems 2004a). Ballard also manufactures the Nexa Power Module, which provides 1.2 kW of electricity and uses compressed hydrogen gas. Like the AirGen, the Nexa fuel cell system is designed to integrate into UPS systems, emergency power generators, and recreational and portable products (Ballard 2003). Finally, Ballard offers the Mark 1030, a 1.3 kW PEM fuel cell module, for integration into residential CHP systems. The Mark 1030 is currently being commercialized in the Japanese CHP market (Ballard 2004b).

Ebara Ballard – a corporation owned by Ballard (49%) and the Japanese energy technology corporation Ebara (51%) – is responsible for bringing Ballard fuel cell residential cogeneration systems to the Japanese market (Ballard 2005). Working with Nippon Oil, Ebara Ballard began to test a kerosene-fueled 1 kW fuel cell cogeneration system in April 2004. The system operates at an electrical efficiency of approximately 33%, with a goal of 36%. While the cost of operation is low, deriving hydrogen from kerosene is more complicated due to its complex carbon structure. Ebara Ballard set a 2006 goal for commercialization (Ebara Ballard 2004).

In addition to the kerosene-fueled prototype, Nippon Oil has developed a 1 kW LPG-fueled system, the Eneos Eco-LP-1, which uses Ebara Ballard fuel cell stacks. According to Nippon Oil, more than 300 orders have been placed for the units, which are installed for free, although residential users are charged 60 000 Yen (approximately \$522) per year to rent the unit. Nippon Oil also is working in collaboration with Mitsubishi Heavy Industries to enter the large stationary commercial applications market with the development of a 10 kW kerosene-fueled system (Adamson 2005).

Ebara Ballard also is working in conjunction with Iwatani International, which provides hydrogen to fuel an independent power unit for use in emergencies, and Tokyo Gas. The system being built with Iwatani, scheduled for commercialization in 2006, has five 850 W power units and hydrogen cylinders with enough fuel to provide 5 h of continuous power (Adamson 2005). Meanwhile, Ebara Ballard's program with Tokyo Gas and Matsushita Electrical has created the LiFuel, a PEM CHP unit that provides excess heat for residential hot water generation and only enough electricity to provide three-fourths of the electricity needed by a household. Tokyo Gas provides the natural gas for these units at a discount to consumers and expects to sell several thousand units by 2008 (Adamson 2005).

Also working on backup-power generation systems for markets such as telecommunications and utilities is Idatech of the USA. Its

ElectraGen5 uses hydrogen in PEM fuel cells for a continuous output of 5 kW of electricity, but the system is available in 1–10 kW sizes. Designed to turn on in the event of a power outage, the included hydrogen storage provides 8 h of operating time at full power (Idatech 2005c).

Fuji Electric Advanced Technology of Japan is working on developing similar sized 1 kW residential PEM fuel cell power units. “Its third generation units have an electrical efficiency of 31%, heat recovery efficiency of 42% and an operating life of 10 000 h; whilst its pre-production unit, currently under development, will have an electrical efficiency of 32%, heat recovery efficiency of 42% and a targeted 20 000 h lifetime,” notes Adamson (2005). Fuji has run several small demonstrations of its fuel cell systems and hopes to commercialize them by 2008 at \$12 000–16 000 each, but with a goal of \$2500–4000 by 2015 (Adamson 2005).

Japan is also home to Toshiba Fuel Cell Power Systems Corporation (TFCPS), which is working in the field of stationary PEM fuel cell systems. The company began testing one of these systems at Cosmos Oil’s Isaka Dam Cycle Park in March 2005. The 700 W CHP system uses LPG for fuel and operates at an electrical efficiency of over 30% and a heat recovery efficiency of over 40% (Cosmo Oil 2005). Toshiba Fuel Cell Power Systems is providing its 1 kW fuel cell units to Japan Energy (150 of the 700 W units by the end of 2008), Taiyo Oil, Kyushu Oil (eight units in the first year), Osaka Gas (also developing SOFC systems with Kyocera), Toho Gas (plans to install 100 of the 1 kW PEM units by 2007) and Idemitsu Oil. Their goal is to make these 1 kW residential units available to consumers for under \$10 000 by 2008 (Adamson 2005). TFCPS also is working on projects with Iwatani International and Mitsubishi Heavy Industries, which plan on installing 100 units over the next 3 years.

Fuel Cell Technologies (FCT), based in Ontario, Canada, is marketing solid oxide fuel cell systems to provide heat and electricity for residential, commercial, and remote sites. Using solid oxide cell stacks from Siemens Westinghouse, FCT’s 40% efficient fuel cell systems provide 1–4 kW of electrical output and about 4 kW of thermal output for hot water or heat. Their 5 kW power system has been used by the University of Alaska Fairbanks as an off-grid electrical system. In the industrial sector, FCT has worked with Ford and Detroit Edison to use paint fumes from the vehicle painting process to power the fuel cell system. For testing in a residential application, FCT is providing four of their 5 kW systems to the Hydrogen Village in Toronto. The CHP units provide heat and electricity to students at the University of Toronto at Mississauga. FCT also is working with companies in Germany and Japan to demonstrate the viability of these residential units (Fuel Cells Technologies Ltd 2004). Other companies developing PEM

fuel cell systems include: New Japan Eco System (2 kW UPS unit), Sanyo Electric (1 kW CHP unit), Altery Freedom ( $5 \times 1$  kW UPS system for the telecommunications market), Shanghai-Shen Li (3 kW and 10 kW units), Matsushita Electric Industrial (1 kW system), and European Fuel Cells (1.5 kW natural gas-powered unit).

The American company, Acumentrics, has developed a tubular SOFC system that requires no fuel reformer. "In contrast to planar or membrane designs, the patented Acumentrics tubular solid oxide fuel cell (T-SOFC) design uses configurations of many small electrolytic tubes made of electroceramic material. The anode is on the inside of the tube and the cathode is on the outside," explains Acumentrics (2006). These SOFC systems are intended to provide backup power or distributed generation either on or off the electric grid. Acumentrics has 2, 5, and 10 kW power generation systems available for commercial and industrial use.

In collaboration with Sumitomo and Nippon Steel, Acumentrics has founded Acumentrics Japan to focus, initially on modifying and testing existing prototypes. The ultimate goal is expanding into large stationary applications in the 20–100 kW range (Adamson 2005). Acumentrics also is working with Merloni Termosanitari, an Italian company, to develop two CHP units that integrate the fuel cell technology from Acumentrics with the MTS heating technology. These residential systems are intended to be marketed to two-family homes in Europe (Adamson 2005).

British company Ceres Power is focusing its research on metal-supported solid oxide fuel cells that operate at an intermediate temperature, lower than typical SOFC systems. These fuel cells are designed to run off a range of fuels including LPG, natural gas, and methanol, making them more attractive commercially. Ceres is working hard to commercialize its product in the distributed generation and CHP markets using fuel cells combined in stacks to produce between 1 and 25 kW of electricity. "Ceres is partnering with British Gas to incorporate its fuel cells in domestic boilers that will produce both heat and electricity. A similar programme is under way with BOC [a global industrial gas company] to develop fuel cell products using bottled gas for applications where connection to the grid is unfeasible or uneconomic," according to Ceres Power (2005).

Other companies developing small SOFC stationary units include Mitsubishi Materials and Kansia Power, which together are developing 1 kW residential power systems. While almost all small stationary applications use either SOFC or PEM fuel cell technology, GS Yuasa Corporation has developed a 1 kW direct methanol fuel cell system that is being tested and the company hopes to commercialize in 2007 (Adamson 2005). Meanwhile, large stationary applications, generally intended for commercial uses, have a wide range of fuel cell technology types.

*Large stationary applications*

While portable and small stationary applications are intended for the residential and consumer markets, there is extensive research into large stationary applications for commercial use. One primary reason for installing large stationary fuel cell units is to provide reliable backup power for places such as hospitals and banks where power disruptions can be very costly. For example, on August 14, 2003, a major power outage affected much of the northeastern United States. However, New York City's Central Park Police Department, powered by a UTC Power stationary fuel cell remained fully functional. Another justification for large stationary fuel cell units is that production of electricity at the site of use - referred to as distributed generation - will lighten the load on overburdened electricity grids.

In 2005 there were more than 60 large stationary fuel cell installations around the world. This brought the total number of generating systems over 10 kW up near 800 (Baker 2005a). While vehicles depend largely on PEM fuel cells and portable applications rely heavily on DMFC technology, large stationary applications are moving toward molten carbonate technology. Phosphoric acid fuel cells had been a major player in the large stationary sector, but manufacturers are moving away from that technology. PEM fuel cells and solid oxide technologies still are being explored by a limited number of companies.

Hybridization, linking fuel cells in parallel to a gas turbine, is being researched in the large stationary fuel cell sector. This technology, intended to increase efficiency, decrease lifetime costs, and increase the recoverable level of waste heat, is being supported by FuelCell Energy, GE Energy, Rolls Royce, and Siemens Westinghouse.

One of the biggest players in the large stationary fuel cell market is FuelCell Energy, based in Connecticut. FuelCell Energy is developing direct fuel cells (DFC), a molten carbonate fuel cell that uses natural gas as an input rather than hydrogen, but without producing the pollutants associated with burning the natural gas. FuelCell Energy claims, "From industrial and commercial settings, to distributed generation on the existing utility grid, the DFC is the most efficient means of generating electric power from fossil fuel in its size range" (FCE 2006a). Direct fuel cells will allow for faster commercialization of stationary fuel cells because the necessary infrastructure is already in place. While current installations use natural gas, FuelCell Energy reports, "The 'fuel flexibility' of our technology also permits us to pursue niche fuels such as municipal digester gas, coal gas, and biomass fuels including ethanol and biogas from farms" (FCE 2006b).

FuelCell Energy already has their DFCs installed in 31 places including "hotels, hospitals, universities, wastewater treatment plants, telecom

and data centers, and commercial and industrial facilities” (FCE 2006c). FuelCell Energy markets three different size electric generators – 250 kW (DFC 300A), 1 MW (DFC 1500) and 2 MW (DFC 3000).

In collaboration with Marubeni, their Japanese partner, FCE has agreed to install a DFC 300A at the Kawasaki Akashi Works near Osaka, Japan. The unit will undergo testing to aid in the development of a Kawasaki-branded carbonate fuel cell power plant that was to be introduced to the Japanese market in 2006 (Baker 2005b). FuelCell also has an alliance with Marubeni in Korea to distribute Direct FuelCell power plants in Korea. A long-term goal is the production of DFCs throughout Asia and eventually the global markets (Baker 2005b).

In another partnership, FuelCell Energy is working with QuestAir Technologies to develop a hydrogen purification system to produce pure hydrogen from the exhaust of a 1 MW DFC1500. The hydrogen produced using this technology could be used to generate electricity and heat or to power a fleet of hydrogen-powered vehicles. Other partnerships include work with Enbridge to develop “a new multi-megawatt product specifically designed for natural gas pipeline applications in the USA and Canada,” and work commissioned by Concurrent Technologies Corporation (CTC) to modify its fuel cell power plant to run on 95% pure propane and have the ability to alternate quickly between fuels. The project, partially funded by the US Department of Defense, Army, and the Army Corps of Engineers, is aimed at providing a secure source of base-load electricity in situations where fuel supplies are threatened (Baker 2005b).

In the field of phosphoric acid fuel cells (PAFC), UTC Fuel Cells, an American corporation, is a market leader. UTC is involved in fuel cell development in all five major fuel cell technologies and has commercialized its products. More than 275 of its PureCell 200s are used to power schools, offices, hospitals, and manufacturing sites in 19 countries. UTC reports that the PureCell system is two times as efficient as the electric grid because there are no transmission losses “and, more importantly, waste heat is captured to generate additional useable energy for heating or cooling” (UTC Power 2005). The PureCell 200 operates using natural gas, but has the option to use anaerobic digester gas instead. It has 200 kW of constant output and an additional 925 000 Btu/h of heat at 140°F. In September 2005, UTC joined forces with Verizon Communications to build the world’s largest fuel cell installation, using seven PureCell 200s to generate 1.4 MW of electricity. “The units providing cooling, heating and power operate as a hybrid system with diesel and dual fuel gas/diesel reciprocating engines, which can generate a total of 4.4 megawatts of electrical power,” according to Baker (2005b). Funded by the US DOE and the New York State Energy Research and Development

Authority, the project is projected to save Verizon \$250 000 per year in power costs. UTC is also involved in additional power generation projects on Long Island as well as New York City and Russia.

In Japan, Fuji Electric is working on both proton exchange membrane fuel cell (PEMFC) and PAFC technologies. Fuji currently has its 100 kW PAFC installed at 15 facilities and reports more than 50 000 h of successful operations. PACF's most recent model has a working life of 15 years, with the fuel cell stack and reformer needing replacement every 7.5 years (Baker 2005b). Other projects using PAFCs include a 2-year test jointly conducted by Nippon Petroleum Gas and Toshiba International Fuel Cells Corporation at Nippon's Niigata LPG Import Terminal. The 200 kW system is fueled by dimethyl ether (DME) and the direct synthesis technology will allow for production of DME from sources such as gasified waste and fermented methane gas from animal manure in addition to the conventional sources of coal and natural gas (Baker 2005b). In addition to its small stationary application units, Toshiba Fuel Cell Power Systems also has developed a 200 kW PAFC system. The PC25C can run off of either propane or anaerobic digester gas and has an electrical efficiency of approximately 40%. As of November 2004, there were over 200 PC25C series units in use globally, with 50 logging over 40 000 h of operating time (Toshiba 2005).

In addition to their work in the development of PAFC technologies, Japanese companies lead in solid oxide fuel cell advancement. J-Power, a Japanese wholesale electricity provider, is developing Integrated Coal Gasification Fuel Cell Combined Cycle (IGFC) technology. According to the company, "the IGFC generating system is made of a triple set of power generators based on fuel cells, gas turbines and steam turbines that use coal gasification technology. When the development is complete, power generation efficiencies of as high as 60% will be possible, and CO<sub>2</sub> emissions should fall 30% compared with existing coal-fired power generators" (J Power 2005). Beginning in March 2007, using funding from the Japanese government and the New Energy and Industrial Technology Development Organization (NEDO), J-Power will begin testing of the IGFC technology at a coal gasification pilot plant. Also funded by NEDO is a joint effort between Mitsubishi Materials and Kansai Electronics to develop a power system that provides at least 10 kW of power and can operate at lower temperatures than other SOFC systems (800°C). These SOFC power modules are expected to be commercially available in 2007.

In addition to the research by J-Power and Mitsubishi Materials, NEDO is funding two mono-block layer built (MOLB) SOFC projects by Mitsubishi Heavy Industries (MHI). Together with Chubu Electric Power, MHI is developing a 200 kW co-generation system as well as a

350 kW system that is combined with a micro gas turbine. While the system currently is not cost competitive, the companies estimate they can reduce the cost to approximately \$4500/kW by 2008–2009. Baker (2005b) reports, “Their intention is to commercialise a 20 MW–50 MW system combined with high efficiency gas turbine in 2010. They have also announced a large thermal power station (a 700 MW SOFC system) to be in operation by 2015, which is a triple combined cycle using SOFC, gas turbine, and a steam turbine.” In addition to the development of SOFC technology, MHI also is involved in the production of PEM fuel cells in conjunction with Nippon Oil, while Chubu Electric Power is conducting tests of molten carbonate fuel cell (MCFC) technology and the potential for diversification of fuel sources.

Nippon Steel and Sumitomo are working with Acumentrics to modify these prototypes to increase the power output to 100 kW and target the larger commercial application market. Acumentrics is already testing two 5 kW systems with Nippon Steel.

Another American company working in the field of SOFC technology is Siemens Power Generation. Among its current demonstrations is a 250 kW CHP system that has been operating at a Kinetics Inc. test facility in Toronto, Canada, since 2003. In addition, Siemens installed a 220 kW SOFC/gas turbine hybrid at the National Fuel Cell Research Center in Irvine, California, as a proof of concept demonstration. Siemens (2006) claims that the hybrid “operated for nearly 3400 h, and achieved an electrical efficiency of ~53%. This is the highest known electrical efficiency achieved by any large-scale fuel cell system. Eventually, such SOFC/GT hybrids should be capable of electrical efficiencies of 60–70%.” Other companies testing SOFC fuel cells include Rolls-Royce, which has a 80 kW unit, and Ztek, which has demonstrated the use of its 1 kW units and now is testing a 25 kW unit with plans to increase to 1 MW units for distributed electricity (Baker 2005b).

North America leads the way in the area of proton exchange membrane fuel cell development for large stationary applications. In June 2005 Hydrogenics Corporation of Canada “announced it is supplying fuel cell power modules to American Power Conversion Corporation (APC), a leading global supplier of high availability systems for network-critical physical infrastructure (NCPI), for its new InfraStruXure with Integrated Fuel Cell System” (Hydrogenics 2005). Hydrogenics will provide 25 of their HyPm XR fuel cell units to APC. The PEM fuel cells are 10 kW each and can be configured in sets of up to three modules. Hydrogen used to power the HyPm is stored in pressurized canisters that each can provide 79 min of 10 kW continuous power (APC 2005). In another project, Hydrogenics is collaborating

with IdaTech, a subsidiary of IDACORP, under a grant from the US Department of Energy to develop a 50 kW PEM fuel cell unit. The project will combine the fuel cell technology from Hydrogenics with the multi-fuel processing technology from IdaTech to demonstrate efficiency increases and consumption decreases at such places as hotels and hospitals (Baker 2005b). While Hydrogenics is a leader in PEM fuel cell technology for stationary applications, it is also heavily involved in providing hydrogen generation and refueling stations for infrastructure development. Hydrogenics has a dozen HySTAT-A hydrogen generators and refueling stations across the United States, Europe, and Asia (Hydrogenics 2006).

Also developing power generation systems for hospitals and hotels is Nuvera of the United States. Focusing on the market for CHP, Nuvera has developed the third generation Avanti, which generates approximately 5 kW of electricity and 7 kW of heat and demonstrates improvements in efficiency and reliability when compared to previous models. The company notes (Nuvera 2006), "Avanti integrates two key components of a fuel cell system - the fuel processor and a PEM fuel cell stack - into a single product, which allows this power system to use natural gas or propane as the primary fuel source and generate clean, efficient energy."

EletroCell, a Brazilian company, is developing and testing prototypes that range in size from only 25 W, used for demonstration purposes, to 10 kW, which will be marketed for residential use. Using three of the 10 kW units, EletroCell has tested a 30 kW prototype. The company plans on its technology reaching the market in the next few years as backup power supply systems (Baker 2005b).

In addition to FCVs, some major auto manufacturers including General Motors and BMW are involved in developing PEM fuel cells for large stationary applications. In February 2004 Dow Chemical Company began using a General Motors fuel cell to generate electricity at its largest chemical manufacturing plant in Freeport, Texas. The manufacturing processes used at the Dow Chemical plant produce hydrogen as a byproduct. Phase 1 of the project, lasting about 6 months, used a fuel cell to generate 75 kW of electricity, enough to power approximately 50 homes. Eventually, Dow and General Motors plan on installing as many as 400 fuel cells, generating 35 MW of electricity (2% of the total electricity needs of the plant) (General Motors 2004a). This collaboration "is the first time a carmaker has used its fuel cell technology to provide electricity and heat for manufacturing," according to General Motors (2004b).

As part of the "The Hague Project," the BMW Group began providing electricity for its sales branch in The Hague in March 2004. The CHP

system uses a PEM fuel cell to provide a nominal output of 4.6 kW of electricity and 7.0 kW of heat. The system uses a reformer located inside the heating unit to convert natural gas from the existing infrastructure to hydrogen for use in the fuel cell. The system, monitored by Vaillant of Germany, had some reliability problems at the inception of the project, but from April through October 2004 reported nearly uninterrupted power and heat (BMW Group 2004).

## **Conclusion**

As is evidenced from the number of companies involved in hydrogen research, many companies believe hydrogen has a bright future. Scores of companies are gaining practical experience with a variety of fuel cell and other hydrogen configurations, ranging from automotive uses to alternative power sources for cell phones and laptops. These experiences will lead to further technological advances and to cost reductions. For some applications, including military, economics alone may not decide whether fuel cells will gain a significant share. Economics will be very important in the success of hydrogen technologies in the automotive sector, unless hydrogen vehicles can offer something that traditional vehicles cannot, such as mobile power sources. It is also possible that long-term upward trends in oil prices or an environmental disaster clearly attributable to our fossil fuel use could mean that we push towards a hydrogen future.

Other technologies aimed at reducing dependence on foreign oil or with clear environmental benefits have failed to capture significant market share over the years. In the 1950s, proponents of nuclear power envisioned electricity so cheap that homeowners in chilly climates would heat their driveways to melt snow. Solar enthusiasts have heralded the possibility of capturing free energy from the sun for decades. Many thought the introduction of electric vehicles in California, such as the GM EV1, heralded the future of zero emission vehicles. And yet, in 2006, nuclear energy's future is questionable in the United States due to high costs and public concerns associated with this technology. Solar panels are relegated largely to remote applications, where electric lines do not reach. And the EV1 was taken off the road with no future plans for a next-generation electric vehicle.

History can be a cruel reminder of technology's failed promises. A clear lesson is that companies and the government should not overhype their technologies or rush inferior ones to market. One bad public experience could doom a whole line of technologies. The number of companies involved in developing multiple hydrogen options indicates real commercial interest and great promise. Clearly, it is important for

governments to support research and demonstration efforts, but ultimately, hydrogen technologies can succeed only if they satisfy a real market demand.

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# Part IV

## The Hydrogen Futures Simulation Model (H<sub>2</sub>Sim)

A hydrogen future offers a possible solution to many of the problems associated with a heavy reliance on oil and other fossil fuels.<sup>1</sup> There also are many competing visions for a future hydrogen economy. Some suggest a decentralized approach, where hydrogen is produced at the fueling station or even at the household level by reforming natural gas or utilizing electrolysis. Others suggest a more centralized approach, producing the hydrogen at large, centrally located plants and distributing the hydrogen by pipeline, truck, rail, or ship. How the hydrogen economy will evolve is dependent on several factors, ranging from economics to government policies.

The Hydrogen Futures Simulation Model was developed as an educational and policy tool to help users understand the various pathways and trade-offs associated with those pathways. H<sub>2</sub>Sim compares various production, storage, distribution, and end use technologies in 2020, an oft-mentioned time frame for when fuel cells and other hydrogen technologies may be mature enough for market deployment.

This book includes a run-time version of H<sub>2</sub>Sim, referred to as the H<sub>2</sub>Sim Elsevier Edition. The reader can use this version of H<sub>2</sub>Sim to explore many of the scenarios and options discussed in this book. While every screen in the full model is viewable with the Elsevier Edition, several assumptions cannot be altered. The full version of the model is available from Sandia National Laboratories.<sup>2</sup>

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<sup>1</sup>Portions of this section were previously published as a Sandia National Laboratories Technical Report: Thomas E. Drennen, Arnold B. Baker, Scott A. Jones, William J. Kamery, Andrew E. Lutz, and Jennifer E. Rosthal, "The Hydrogen Futures Simulation Technical Description", SAND2004-4937, October 2004.

<sup>2</sup>Contact the primary author, Thomas Drennen, for further information (drennen@hws.edu).

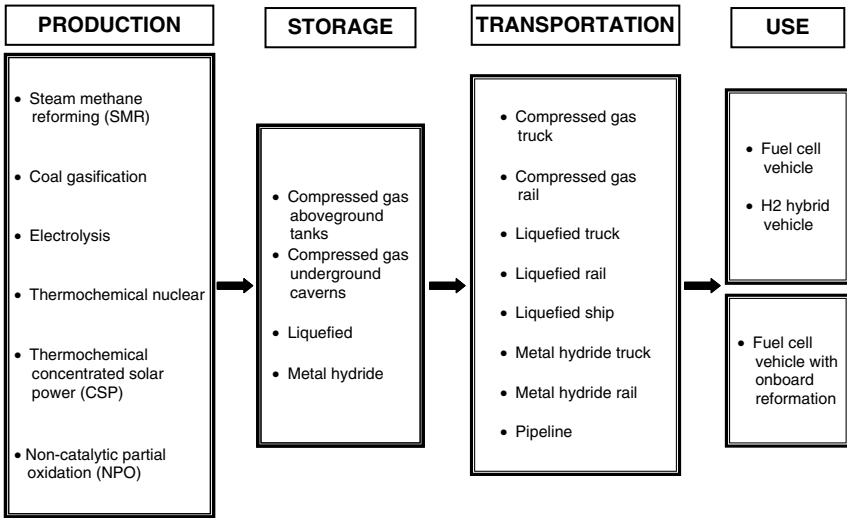


Figure P.1. Hydrogen pathways.

Figure P.1 illustrates potential pathways for hydrogen production and distribution. Several production technologies exist that can separate hydrogen from various feedstocks, including natural gas, coal, crude oil, and water. Transportation options include trucks, rail, ships, or pipelines. Depending on the system configuration, hydrogen may need to be stored at the production facility prior to transportation to the fueling station. Hydrogen can be stored as a gas, a liquid, or trapped in a solid medium (metal hydrides). Finally, several options for using hydrogen (end use) exist. In the transportation sector, hydrogen can be converted to electricity in fuel cells that power an electric motor or be directly combusted in internal combustion engines. Similarly, hydrogen can be used in stationary systems to provide both electricity and heat for residential, commercial, or industrial applications.

A hydrogen future could provide many environmental benefits. The lack of tailpipe emissions would significantly improve urban air quality. Hydrogen offers the potential of reducing future emissions of carbon dioxide, a key greenhouse gas. However, if the hydrogen is derived from hydrocarbons, the carbon must be sequestered to gain this environmental benefit. Several methods for carbon sequestration are in use today or have been demonstrated at the pilot scale, and other hypothetical methods have been developed.

H<sub>2</sub>Sim allows the user to vary production processes, as well as storage and transportation options, for delivering hydrogen for use in the

transportation sector or for stationary cells. H<sub>2</sub>Sim includes options for carbon sequestration. While Figure P.1 illustrates several potential sequestration options, H<sub>2</sub>Sim currently limits the options to include sequestration in underground wells, such as depleted reservoirs. H<sub>2</sub>Sim does not provide a detailed end use analysis for stationary applications at this time.

Several other groups have conducted detailed economic analyses of various hydrogen technologies. Padro and Putsche (1999) provided an excellent overview of the costs for different technologies and an extensive list of references. Several works from the National Renewable Energy Laboratory (NREL) examined hydrogen costs, including Amos (1998), Mann (1995), Spath and Mann (2001), and Simbeck and Chang (2002). Thomas and co-workers (1997, 1999) have completed a series of economic studies of hydrogen applied to various production paths and distribution schemes. Ogden et al. (1998, 1999a,b) have performed economic analyses of a variety of hydrogen infrastructure schemes, including regional case studies. Williams (1996, 2001) and Blok et al. (1997) included carbon sequestration in the economic analyses. Mintz et al. (2002) analyzed different pathways to supply hydrogen for vehicles. More recently, a National Academy of Sciences (2004) report analyzed the likely costs and technical barriers to various hydrogen pathways. Within the United States government, there is a significant effort underway to standardize the methodologies used for hydrogen systems analysis. This effort, supported by the Department of Energy, is referred to as the H2A project.<sup>3</sup>

H<sub>2</sub>Sim was developed by a team of scientists, engineers, and economists at Sandia National Laboratories. What sets apart the H<sub>2</sub>Sim approach from other efforts to construct economic models for hydrogen is the integration of the hydrogen system components into a software-learning tool that easily can be used for parametric studies. The baseline values used in the model were gleaned from the literature or from Sandia experts, but the user can vary the parameters and examine their effect on the cost of hydrogen. While the model is generic, in that it does not apply to a specific region, it provides a high-level picture of the cost trade-offs that would have to be more carefully examined for specific applications.

The following three chapters describe the technical and economic assumptions in H<sub>2</sub>Sim and compare results for various hydrogen pathways. Chapter 6 looks at the options for producing hydrogen.

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<sup>3</sup>Details for the H2A report can be found at [http://www.hydrogen.energy.gov/h2a\\_analysis.html](http://www.hydrogen.energy.gov/h2a_analysis.html).

Distribution and storage options are discussed in chapter 7. Chapter 8 focuses on transportation end use options and discusses insights from the model, specifically what it implies about hydrogen's future. Chapter 6 contains a less technical version of this material and for many readers may suffice.

# Chapter 6

## Hydrogen Production

Although hydrogen is an abundant resource, it is not found in its elemental form. Hydrogen production involves stripping the hydrogen out of hydrocarbons (coal, oil, and natural gas) or water. Several production options exist, including steam reformation of hydrocarbons, usually natural gas; coal gasification; electrolysis; or thermochemical processes, utilizing high-temperature heat from nuclear or concentrated solar-power technologies.

Some of these production technologies (reformation, gasification, NPO, and electrolysis) already are available commercially, whereas others may be future options (thermochemical processes). Certain technologies only make sense for large-scale, centralized hydrogen production (coal gasification and thermochemical nuclear), whereas others offer a decentralized, small-scale solution to hydrogen production (steam reforming and electrolysis).

Globally, about 16 trillion ft<sup>3</sup> of hydrogen are used annually in the chemical and manufacturing sectors (NAE 2004). Hydrogen is used in the manufacture of ammonia-based fertilizer; in refinery operations to convert heavy oil into more useable forms (hydrocracking); and in various reformulated gasoline blends that meet local air pollution standards. Hydrogen routinely is added to unsaturated fats such as margarine to make them spreadable and to increase shelf life. The NAE (2004) study estimates that of this global total, 48% of the hydrogen is derived from natural gas, 30% from oil, 18% from coal, and 4% from electrolysis.

This section explains each production option and the assumptions used in H<sub>2</sub>Sim. For each process, there are separate capital, feedstock, and operating and maintenance (O&M) costs. Since many of these technologies are not yet commercially available, it is difficult to give precise or consistent estimates for their various costs. The estimates chosen represent the model developers' estimates for 2020. Undoubtedly, some of these estimates will either under- or overestimate the 2020 cost and performance characteristics. With this in mind, H<sub>2</sub>Sim was designed

to quickly show projected production costs for a wide range of initial assumptions.

Costs are estimated using a levelized cost of energy (LCOE) approach. The LCOE approach often is used as an economic measure of energy costs since it allows for comparison of technologies with different capital and operating costs, construction times, and capacity factors. The LCOE calculation is given by

$$\text{LCOE} = \frac{IFCR}{Q} + \frac{\text{O\&M}}{Q} + \frac{E}{Q} \quad (1)$$

where  $I$  is the capital investment, including financing charges; FCR is fixed charge rate;  $Q$  is annual plant output (kWh); O&M is fixed and variable O&M;  $E$  is the externality costs.

The methodology for calculating the capital cost component is consistent across technologies. Financing costs assume that capital expenditures are uniformly distributed over the time of construction, and assume a default real interest rate of 5%.<sup>1</sup> Once operational, annual capital costs are determined by multiplying the total capital cost, including finance costs, by a fixed charge rate (FCR):

$$\text{FCR} = \frac{\text{CRF}[1 - bT \sum_{n=1}^M V_n / (1 + d_n)^n - t_c]}{(1 - T)} + p_1 + p_2 \quad (2)$$

where CRF is the capital recovery factor;  $b$  the fraction of investment that can be depreciated;  $T$  the effective tax rate;  $M$  the depreciation period;  $V_n$  the fraction of depreciable base in year  $n$ ;  $d_n$  the nominal discount rate;  $t_c$  the tax credit;  $p_1$  the annual insurance cost; and  $p_2$  is the other taxes.

The FCR typically falls between 0.11 and 0.17 and represents the percentage of capital costs that must be recovered each year. For example, for a \$1 million capital investment and an FCR of 0.15, the annual capital cost for that investment is \$150 000.

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<sup>1</sup> Interest rates refer to the cost of borrowing money from banks, investors, or other sources. Discount rates refer to the "cost of money". The discount rate may be higher than the interest rate if the borrower requires a higher rate of return than implied by the interest rate. The discount rate is often referred to as the opportunity cost of money. "Real" rates means adjusted for inflation. "Nominal" refers to unadjusted values. For example, a gallon of gas averaged \$1.31 in 1981 (nominal price). Adjusted for inflation (real price), that same gallon of gasoline cost \$2.51 in 2005 prices.

Depreciation follows the United States' Modified Accelerated Cost Recovery System (MACRS). Under IRS regulations, most utility-type investments use either a 15- or 20-year depreciation schedule. Certain investments, such as renewables, are allowed to use a 5-year depreciation schedule. The capital recovery factor (CRF) is calculated using

$$\text{CRF} = r \frac{(1+r)^n}{(1+r)^n - 1} \quad (3)$$

where  $r$  is the real discount rate (initially set at 10%) and  $n$  the plant life (initially 20).

Financing costs assume that capital expenditures are uniformly distributed over the time of construction.

The base case, or default assumptions, of H<sub>2</sub>Sim are summarized in Table 6.1. For each option, the base case assumptions use projected cost and performance estimates for 2020, as reported in the literature or as estimated by experts at Sandia National Laboratories.<sup>2</sup> As some of these technologies, such as the thermochemical processes, are not yet commercially available, significant uncertainty exists. H<sub>2</sub>Sim is designed to illustrate hydrogen production costs in 2020 for a wide range of capital costs, allowing the user to understand the sensitivity of the estimated target costs. All numbers in this paper are reported in terms of the hydrogen content. For example, production facilities are reported

Table 6.1. Production facility assumptions

Production method	Capital cost (\$/kW-H <sub>2</sub> )	O&M cost (\$/kWhr-H <sub>2</sub> )	Thermal efficiency (%)	Capacity factor (%)	Construction time (years)	Facility size (MW-H <sub>2</sub> )
Reformation	500.9	0.00452	70.0	100	3	138
Coal gasification	592.4	0.00337	70.3	80	4	1000
Electrolysis	300.0	0.00131	70 <sup>1</sup>	100	1	500
Therm. Ch. CSP	593.6	0.01200	45 <sup>1</sup>	69	3	497
Therm. Ch. nuclear	669.0	0.00135	43 <sup>1</sup>	90	3	600
NPO	500.5	0.00254	36.8	90	3	100

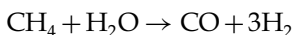
<sup>1</sup> Efficiencies are for production process, not fuel conversion.

<sup>2</sup> The estimates for NPO are estimates for currently operating processes. We do not assume considerable improvement in these costs over the forecast period.

in units of MW-H<sub>2</sub>. A MW of installed hydrogen capacity is equal to 720 kg/day<sup>3</sup> on a lower heating value<sup>4</sup> basis.<sup>5</sup>

### Steam Methane Reformation

Steam reforming of hydrocarbons currently is the most widely used method for producing hydrogen. The most common feedstock for this process is methane. The basic process involves steam heating of the hydrocarbon, such as natural gas (CH<sub>4</sub>), in a catalytic reactor. CH<sub>4</sub> reacts with water vapor under high pressure and temperature, resulting in carbon monoxide and hydrogen:



The process then involves a water-gas shift step, which produces CO<sub>2</sub> and H<sub>2</sub>. The CO<sub>2</sub> and H<sub>2</sub> gas streams are further separated using a pressure swing absorption (PSA) process.

Steam reforming is an option for either large-scale centralized facilities or small-scale decentralized facilities, such as the fueling station or even the home. There are economies of scale. Nemanich (2003) estimates costs are minimized for a plant size of 138 MW-H<sub>2</sub>, or 100 000 kg H<sub>2</sub>/day. A steam methane reformation (SMR) facility of this size is sufficient for fueling 150 000 cars. While economies of scale for hydrogen production favor larger, centralized plants, the costs of transporting the hydrogen to the point of end use are not insignificant. Smaller, but more expensive, decentralized SMR facilities may be economically competitive by greatly reducing transportation and storage costs.

Lutz (2005) estimates the relationship between the reformation facility size and capital cost:

$$P_{\text{Capital}} = P_0 (M_{\text{H}_2})^A \quad (4)$$

where  $P_0 = 22\,000$  \$/yr;  $M_{\text{H}_2}$  is the production rate (kg/day);  $A$  a scaling factor (default = 0.7).

<sup>3</sup>  $1 \text{ MW} \times \text{J/s/W} \times 3600 \text{ s/h} \times 24 \text{ h/day} \times \text{kg}/120 \text{ MJ} = 720 \text{ kg/day}$ .

<sup>4</sup> H<sub>2</sub>Sim uses the lower heating value of hydrogen, 120 MJ/kg, for all calculations. Others, including Williams, utilize the higher heating value of 142 MJ/kg. The lower heating value refers to the energy available in converting hydrogen to steam, whereas the higher heating value assumes the output is liquid.

<sup>5</sup> Similarly, a capital cost estimate of 100 \$/kW-H<sub>2</sub> translates into a capital cost of 138 \$-day/kg (100 \$/kJ  $\times$  120 000 kJ/kg  $\times$  h/3600 s  $\times$  day/24 h = 138 \$day/kg). The use of \$/kW-H<sub>2</sub> makes it much easier to compare to costs of installed electrical capacity.

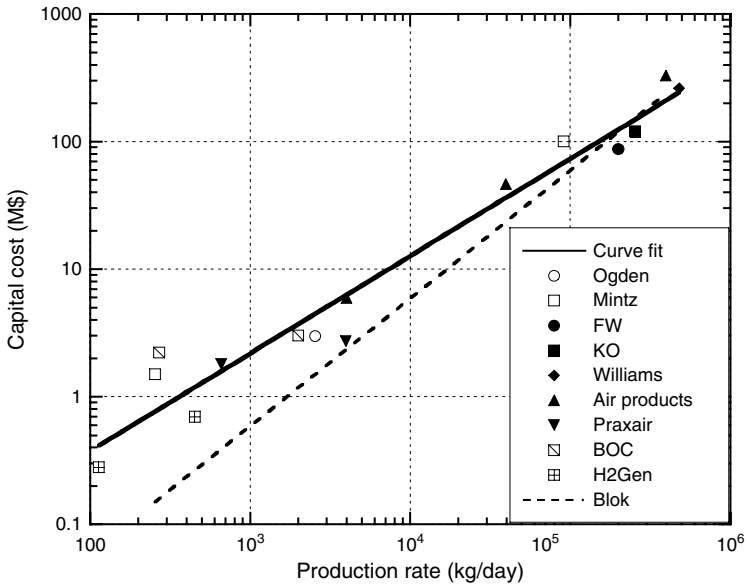


Figure 6.1. Derived relationship between capital cost and production capacity (rate) for SMR.

Figure 6.1 illustrates the estimated relationship for a wide range of estimates found in the literature. An estimated relationship from Blok et al. (1997) is shown for comparison. This line is below Lutz’s estimate and includes a different slope, indicating there is remaining uncertainty regarding these estimates.<sup>6</sup> Equation (2) is not actually used by H<sub>2</sub>Sim, as H<sub>2</sub>Sim calculates hydrogen production costs for all assumed capital costs. Rather, this equation is useful for considering questions of scale, including the projected capital costs associated with smaller, distributed reformers.

Using Equation (2), the capital cost for a 100 000 kg/day facility would be \$69.5 million, or approximately 500 \$/kW-H<sub>2</sub>. The capital costs for a smaller 1000 kg/day facility (possibly located at a fueling station) would be \$2.8 million, or about 2000 \$/kW-H<sub>2</sub>. However, this higher capital cost may be more than offset by reduced storage and transportation costs. For comparison, both Blok et al. (1997) and Thomas et al. (1997)

<sup>6</sup> Equation (2) is not actually used by H<sub>2</sub>Sim, as H<sub>2</sub>Sim calculates hydrogen production costs for all assumed capital costs. Rather, this equation is useful for considering questions of scale, including the projected capital costs associated with smaller, distributed reformers.

suggest lower costs may be possible for mass-produced units. Thomas et al. (1997) estimate a capital cost of 1120 \$/kW for a 450 kg/day unit and 2029 \$/kW for a 100 kg/day unit.

The next cost to consider is that of the feedstock from which the hydrogen is produced – in this case, natural gas. Feedstock costs consider the cost of the input, natural gas ( $P_{\text{feedstock}}$ ), and the overall efficiency,  $\eta$ , of converting that feedstock to hydrogen. The basic relationship is

$$P_{\text{Fuel}} = \frac{P_{\text{feedstock}}}{\eta} \quad (5)$$

H<sub>2</sub>Sim uses a default thermal efficiency of 70%.

SMR production costs are very sensitive to the price of the feedstock. One of the disadvantages of the widespread use of SMR is the potential for volatility of natural gas prices, although such risks can be mitigated, at least partially, through future contracts and hedging mechanisms. Nemanich (2003) estimates that SMR is competitive with hydrogen from coal gasification if natural gas prices are less than 3 \$/MBtu. The delivered costs of natural gas to electric utility plants averaged 6.11, 5.57, and 3.68 \$/MBtu in 2004, 2003, and 2002, respectively. Natural gas prices peaked at a high of 9.36 \$/MBtu in January 2001. For the same years (2004–2002), coal prices averaged: 1.27, 1.28, and 1.27 \$/MBtu (EIA 2006). The DOE long-term projections assume natural gas prices will average 5.44 \$/MBtu by 2025 (EIA 2005).

The literature review suggests that O&M costs for a 100 000 kg/day SMR facility range from 3 million to 8 million \$/year. H<sub>2</sub>Sim assumes O&M costs are a fixed fraction of overnight capital costs (4% per year), as suggested by Williams (2001). For the 100 000 kg/day facility mentioned earlier, this would imply O&M costs of 2.8 million \$/year, at the low end of the literature range.

## Coal Gasification

Hydrogen can be produced by gasifying coal. Unlike steam reforming technologies, coal gasification only makes sense as a centralized production option, due to economies of scale. Several proponents of this option, including Williams (2001), argue that for countries with large reserves, such as the United States, India, and China, coal gasification, along with sequestration of the carbon, may be the least expensive and most attractive option for the large-scale supply of hydrogen.

Coal gasification is a multistep process. Oxygen and steam are used to produce synthesis gas (CO and H<sub>2</sub>); the H<sub>2</sub> then is separated out using a water–gas shift reaction and PSA method, similar to the reformation

process. In an optimized system, the synthesis gas produced can be used in a combined cycle plant to produce electricity as well as hydrogen.<sup>7</sup>

Williams estimates capital costs, without carbon capture and sequestration, of \$592.4 million for a 1000 MW-H<sub>2</sub> facility operating in 2020. Annual capital costs are a function of financed capital costs, construction time, and the CRF, as given by Equation (1).

As with reformation, feedstock costs are determined using Equation (3). The default thermal efficiency is 70.3%, as estimated by Williams (2001). As with SMR, H<sub>2</sub>Sim assumes O&M costs equal to 4% of overnight capital costs.

## Electrolysis

Electrolysis is a commercially viable technology for producing hydrogen and is used today for production of pure oxygen for uses in places such as hospitals and submarines. The basic process is well known: by placing positive and negative electrodes in water, the water is disassociated into hydrogen and oxygen. As economy of scale issues are not as limiting for electrolyzers as other production options, electrolyzers are a viable option for decentralized production. However, electricity or the associated fuel must still be transported. The main cost associated with this option is the electricity.

Proponents of this option suggest the use of cheap, off-peak electricity to produce hydrogen. However, this only works for small-scale production, as peak electricity prices would begin to increase as demand increased. The underutilization of the electrolysis equipment itself would increase projected costs (producing less hydrogen with the same capital costs). In a full-scale hydrogen economy, wide-scale use of electrolysis would require the construction of significant additional generation capability. Several energy industry groups, including both renewable and nuclear energy groups, suggest their technology could power distributed electrolysis systems, providing hydrogen at either the fueling station or even at the household level. For example, the Nuclear Energy Institute (NEI) quotes an estimate by Walters et al. (2002) that 240 new nuclear plants in the United States could power the country's entire transportation.<sup>8</sup>

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<sup>7</sup> H<sub>2</sub>Sim does not currently consider electricity credits in the economic analysis. Including these credits may further reduce projected costs, depending on the specific assumptions. Likewise, this analysis does not consider possible O<sub>2</sub> credits associated with the electrolysis option.

<sup>8</sup> Estimate assumes US cars travel 2600 billion miles per year and need 0.013 kg H<sub>2</sub>/mile driven (Walters et al, 2002).

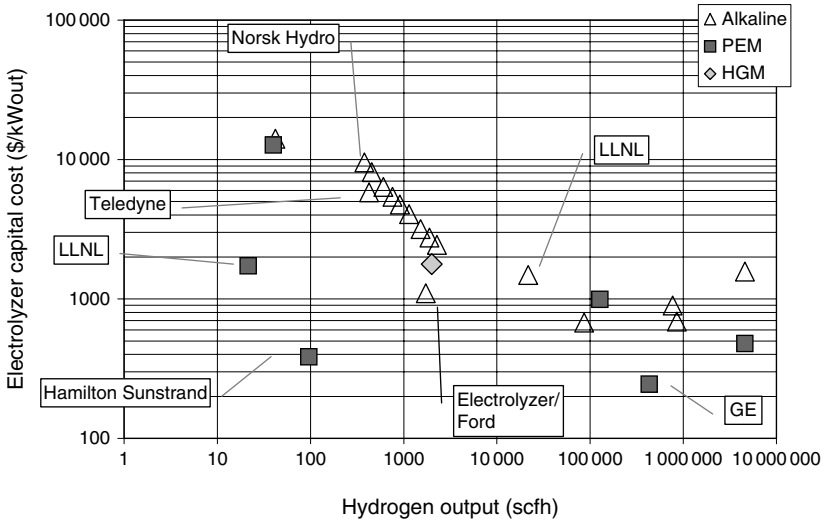


Figure 6.2. Estimated electrolyzer cost.

Capital cost estimates for electrolyzers vary widely (Figure 6.2), depending on type and size. While proton exchange membrane electrolyzers are currently around 1000 \$/kW, several sources suggest that these costs could fall to around 300 \$/kW by 2020 if these units are mass produced (NAE 2004; Schroeder 2004; Williams 2001). Others, including Thomas (2003), suggest that the 300 \$/kW target is highly optimistic, noting that current electrolyzers often exceed 2000 \$/kW (Figure 6.2).  $H_2Sim$  uses the optimistic estimates as the base numbers, as they demonstrate the lowest likely cost of hydrogen produced with this method.

The efficiency of the electrolysis process is estimated to be between 70 and 85%. The default efficiency in  $H_2Sim$  is 70%. Williams (2001) estimates low operation and maintenance costs at approximately one-tenth of a cent per kilowatt hour used. However, as previously mentioned, the primary cost of electrolysis is the electricity required to perform the process.

Electricity costs are projected by  $H_2Sim$  for advanced coal, combined cycle natural gas, natural gas combustion turbines, nuclear, wind, solar thermal, and solar photovoltaic (PV).<sup>9</sup> Projected prices are for the production costs from plants built in 2020 and equipped with the best

<sup>9</sup> The costs given in this paper are for year 2004 technologies for each option.

Table 6.2. Cost and performance characteristics for new generating plants (2003 \$)

	Capital (\$/kW)	Fixed O&M (\$/kW)	Variable O&M (\$/kWhr)	Fuel (\$/MBtu)	Years to construct	Plant size (MW)	Average capacity factor (%)	Heat rate (MBtu/ kWhr)
Nuclear	1694	60.06	0.00044	0.43	6	600	90	10 400
Coal	1134	24.36	0.00406	1.29	4	400	85	8844
Gas CC	517	10.35	0.00177	5.92	3	400	85	6752
Gas CT	356	9.31	0.00280	5.92	2	120	30	9183
Solar PV	3868	10.34	0	0	2	5	24	10 280
Solar thermal	1983	50.23	0	0	3	100	33	10 280
Geo- thermal	2063	104.98	0	0	4	50	95	45 335
Wind	1049	26.81	0	0	3	50	44	0

available pollution control technologies. Assumptions about capital and feedstock costs for the new generating facilities are taken from the EIA (2005). The key assumptions are summarized in Table 6.2. While H<sub>2</sub>Sim defaults to these assumptions, the user can vary the assumptions and view the implications for electricity – and hence electrolysis-produced hydrogen – costs. For example, the user can explore the effect of extended electricity plant construction time or test the economic competitiveness of combined cycle plants at higher projected natural gas prices (Drennen et al. 2003b).

The electricity production costs estimated in H<sub>2</sub>Sim are the levelized costs of electricity over the life of the plant. LCOE often are used as an economic measure of electricity costs as they allow for comparison of technologies with different capital and operating costs over time, as well as different construction times, capacity factors, and plant lives. The LCOE methodology is identical to that used for calculating hydrogen production costs [Equations (1)–(3)].

The electricity prices estimated by H<sub>2</sub>Sim are at the plant gate. If hydrogen production is not done on-site, one must include transmission and distribution costs, typically in the 2 cent/kWh range. H<sub>2</sub>Sim allows the user to evaluate the impact of these prices on hydrogen, as well as consider the impact of off-peak electricity. Table 6.3 summarizes the default assumptions about electricity costs in 2020.

## Thermochemical Processes

Thermochemical processes can produce hydrogen from water using high-temperature heat from either nuclear or concentrated solar power (CSP). There are over 100 thermochemical cycles for hydrogen production in the operating temperature range of 600–2500°C, where direct

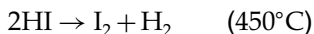
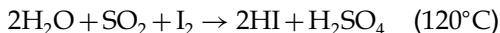
Table 6.3. Projected 2020 electricity costs from GenSim

	Electricity cost (cents/kWh)
Nuclear	5.26
Coal	4.48
Gas CC	5.47
Gas CT	8.20
Solar PV	25.97
Solar thermal	11.54
Geothermal	4.97
Wind	4.62

Source: Drennen et al. (2003).

dissociation of water occurs. In general, as temperatures decrease, the cycles have more intermediate chemical steps and lower efficiency.

Of all the thermochemical cycles, several sources (NAE 2004; Shultz 2003) suggest the most promising cycle is the sulfur-iodine (S-I).<sup>10</sup> The basic process involves combining water with sulfur dioxide and iodine at temperatures of approximately 120°C to form H<sub>2</sub>SO<sub>4</sub> and HI. The HI then can be disassociated at 450°C to produce iodine and hydrogen. The H<sub>2</sub>SO<sub>4</sub> is recycled by heating at 800°C to produce oxygen, sulfur dioxide, and water. The complete cycle is summarized below.



A key advantage of the S-I cycle is that the chemicals all are recycled; there are no effluents. The key challenge is that the process requires high temperatures (800°C) and is still in the experimental stages.

#### *Thermochemical nuclear*

Schultz (2003) estimates the costs for a nuclear thermochemical facility utilizing the S-I cycle. The estimated capital cost for the hydrogen

<sup>10</sup>Several hundred potential thermochemical reactions exist. NAE (2004) state that the two most likely cycles for the production of hydrogen from water are the sulfur-iodine (S-I) and calcium-bromine-iron cycles.

production facility is 669\$/kW-H<sub>2</sub>. Schultz estimates O&M costs, including fuel and waste, to be approximately 7% of the overnight capital costs. H<sub>2</sub>Sim relies on DOE forecasts for nuclear fuel and waste disposal costs. The non-fuel O&M is 1.35 \$/MWh-H<sub>2</sub>. Schultz estimates that for a 50% efficient process, the cost of produced hydrogen is 1.43 \$/kg.<sup>11</sup>

### *Thermochemical concentrated solar power*

The CSP estimates rely heavily on assumptions for the nuclear thermochemical facility for cost estimates for the S-I cycle. Jones (2005) notes that a different cycle may be preferable for use with CSP technologies for several reasons including

- the intermittent, diurnal nature of terrestrial solar resources may favor cycles with efficient heat recovery, solid phase reactants, and a low ratio of fixed to variable costs.
- the ability to heat reactants via direct illumination (photons), unique to concentrating solar technologies, reduces the materials obstacles associated with very high operating temperature cycles (e.g., the Zn/ZnO cycle operating at 1700°C<sup>12</sup>).

However, until the study for CSP is complete and performance and cost estimates for commercial plants developed, the best available information about thermochemical hydrogen production comes from the nuclear studies. Consequently, the basis for the CSP inputs used in this model is the same as for the nuclear thermochemical case – based on the sulfur-iodine cycle cost and performance information from Schultz (2003).

Thermal storage technologies enable a solar resource with a nominal 25% capacity factor to be “spread” out to produce a 69–72% capacity factor that operates at lower output. This technology was proven at the Solar Two plant (Pacheco et al. 2002; Reilly and Kolb 2001) and uses fully commercial technology and commodity materials. Current thermal storage technology is low-cost molten-nitrate salt useful to about 650°C,

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<sup>11</sup> Schultz’s assumptions include: regulated utility with a CRF of 12.6%, 90% capacity factor, 3-year construction period, and a 10% interest rate. The results assume a higher heating value (HHV) of hydrogen of 142 MJ/kg-H<sub>2</sub>.

<sup>12</sup> A solar chemical reactor concept with a windowed rotating cavity-receiver lined with ZnO particles that are held by centrifugal force has been tested. With this arrangement, ZnO is directly exposed to high-flux solar irradiation and serves simultaneously the functions of radiant absorber, thermal insulator, and chemical reactant. The direct irradiation concept provides a very efficient means of heat transfer directly to the reaction site and permits durable metals (rather than ceramics) to be used for reactor wall construction.

but higher temperature options may be applicable in some cases. It is assumed that a thermochemical cycle similar to the sulfur-iodine cycle is found that is compatible with current or future thermal storage technologies. This enables us to use fairly well-defined cost and performance inputs to the model.

Based on the work of Sargent and Lundy (2003), the estimated capital cost of the CSP facility is \$403 million and the H<sub>2</sub> thermochemical facility is \$428 million.<sup>13</sup> Based on the projected hydrogen output of the facility, the combined capital cost is 593 \$/kW-H<sub>2</sub>; O&M cost is 0.012 \$/kWh.

### **Non-catalytic Partial Oxidation**

Another method of production, widely used by refineries, is partial oxidation of hydrocarbons such as crude oil or natural gas. This process is widely used at European refineries to produce hydrogen additives for fuels, petrochemicals, and other hydrogen uses. The basic process is carried out at temperatures of 1200–1450°C and requires pure oxygen. The NPO process is inherently less efficient than steam reforming.

Based on existing technology, a refinery hydrogen unit, using crude oil as a feedstock and a rated output of 100MW-H<sub>2</sub>, has a capital cost of \$50 million, or an overnight capital cost of approximately 500.5 \$/kW-H<sub>2</sub> (CONCAWE 1999). Based on a thermal efficiency of 36.8%, the crude oil input for this facility is estimated at 8.6 million GJ per year, or 3.1 million GJ-H<sub>2</sub>. The O&M costs are difficult to separate from that of the refinery itself. H<sub>2</sub>Sim initially assumes annual O&M costs for the hydrogen refinery unit are 4% of the overnight capital costs.

While the costs for the other production facilities in H<sub>2</sub>Sim are estimates for 2020, the NPO estimates are for a facility built in 2005. H<sub>2</sub>Sim assumes no large changes in these costs (adjusted for inflation) by 2020. The real room for improvement with NPO is the overall efficiency.

### *Carbon capture and sequestration*

If hydrocarbons are used for the production of hydrogen, whether as a feedstock or for the production of electricity, then there will be emissions of carbon dioxide. In reality, cars using hydrogen produced via coal gasification could release higher amounts of carbon dioxide than current vehicles. As concerns about climate change propel the move to a hydrogen economy, it is important to discuss the carbon implications

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<sup>13</sup>This estimate assumes a 1.4GWt solar plant, with a 69% capacity factor and an efficiency of 45% for the H<sub>2</sub> thermochemical facility.

of various strategies and whether carbon capture and sequestration is a viable option.

Dealing with possible CO<sub>2</sub> emissions involves first capturing the CO<sub>2</sub> from the production process and then transporting the CO<sub>2</sub> to a suitable site, such as geologic formations or perhaps the deep ocean, where a large percentage of the CO<sub>2</sub> is expected to remain indefinitely. Ongoing demonstration projects in Norway and Canada may provide needed additional detail regarding the feasibility of long-term storage of CO<sub>2</sub> in deep geologic formations. In addition, CO<sub>2</sub> routinely is injected into partially depleted oil wells as a means of increasing the amount of oil ultimately recoverable from the wells. This process, termed enhanced oil recovery, has not, however, demonstrated the long-term viability of carbon storage. One of the largest projects involves piping the CO<sub>2</sub> 800 km from southwestern Colorado to West Texas.

Capturing the CO<sub>2</sub> released from the production of electricity is a complicated and expensive process. Recent estimates on the costs of capturing CO<sub>2</sub> from electricity production range from 54 \$/tC for integrated gas combined cycle plants to 110 \$/tC for pulverized coal facilities (EPRI 2000). Such costs would add significantly to the expense of generating electricity and hence using electrolysis for electricity. A 50 \$/tC carbon charge would increase the cost of electricity from integrated gasification combined cycle and coal facilities by 1.16 and 0.49 cents/kWh, respectively (Drennen et al. 2003a).

Technically, it is far simpler to remove the CO<sub>2</sub> from either natural gas reformation or coal gasification.

#### *Carbon capture from coal gasification*

H<sub>2</sub>Sim relies on a methodology outlined by Ogden (2002). Ogden's analysis considers carbon capture from large-scale hydrogen and electricity facilities utilizing either natural gas or coal as a feedstock. The captured carbon is then compressed to 15 MPa (2176 psi) for pipeline transmission as a supercritical fluid and injected into underground reservoirs.

Williams provides a detailed analysis of required plant modifications for capturing the CO<sub>2</sub> from a 1000 MW-H<sub>2</sub> hydrogen and electricity facility. These modifications increase the estimated overnight costs by approximately 14.8% (Williams 2001). Williams estimates there is a 2.6% efficiency penalty associated with the carbon capture. In Williams' analysis, CO<sub>2</sub> emissions are reduced to 2.62 kgC/GJ<sub>H<sub>2</sub></sub> from 36.33 kgC/GJ<sub>H<sub>2</sub></sub>, a 92% reduction in CO<sub>2</sub> emissions. The recent NAE study (2004) is more conservative, assuming that future technologies will capture up to 87% of the CO<sub>2</sub> that would be vented in the absence of the carbon capture modifications.

*Carbon capture from natural gas reformation*

During the steam reformation of natural gas, a large percentage of the CO<sub>2</sub> already is separated. According to Blok et al. (1997), CO<sub>2</sub> normally leaves the plant in two streams: “in a diluted stream as a component of the reformer stack gases (about 30% of the total) and in a concentrated stream that is separated from the hydrogen in the pressure swing absorption (PSA) units.” Accordingly, very little additional capital is required to capture the CO<sub>2</sub> exiting the plant in the concentrated stream. Based on Blok et al., the additional capital cost is in the order of 2.8% of the capital cost of the reformation facility.

Both Williams (2001) and NAE assume a higher percentage of CO<sub>2</sub> is captured, 84%. The estimated costs of capturing this additional CO<sub>2</sub> are not minimal. Williams estimates capital costs increase about 32%. Based on this, H<sub>2</sub>Sim assumes that the removal of 84% of the CO<sub>2</sub> will increase the capital costs for the reformation plant from 501 to 661.2 \$/kW-H<sub>2</sub>. H<sub>2</sub>Sim assumes O&M costs of 4% on the additional costs. It assumes an efficiency penalty of 3% associated with the carbon capture.

*Carbon transport and disposal*

Once captured, the CO<sub>2</sub> must be transported to the eventual storage site and injected into wells. Ogden (2002) notes these disposal costs ( $C_D$ ) are the sum of the pipeline transport costs ( $C_{PT}$ ), the costs of drilling and operating the disposal wells ( $C_{DW}$ ), and any surface piping that connects various disposal wells in large operations ( $C_{SP}$ ):

$$C_D = C_{PT} + C_{DW} + C_{SP} \quad (6)$$

For pipeline transport costs, Ogden estimates the following relationship:

$$C_{PT} = C_{PT(0)} \left( \frac{Q}{Q_0} \right)^{-0.52} \left( \frac{L}{L_0} \right)^{1.24} \quad (7)$$

where  $C_{PT}(0) = 3.51$  \$/tCO<sub>2</sub>;  $Q_0 = 445.9$  tCO<sub>2</sub>/h;  $L_0 = 100$  km.

Ogden estimates the cost of the disposal wells, in millions of dollars, as

$$C_{DW} = 1 + 1.25D_w \quad (8)$$

where  $D_w$  = depth of well.

For a 2-km deep well, Ogden’s base and the default case in H<sub>2</sub>Sim, the capital cost would be \$3.5 million. This capital cost is handled in the same manner as are all other capital costs in H<sub>2</sub>Sim.

In the case of large sequestration projects, there will be additional piping connecting the various surface wells. Ogden assumes that each well can handle about 2500 tCO<sub>2</sub>/day. For greater quantities, additional wells are needed. The cost of each additional well is calculated using Equation (8). The cost of surface piping for rates above 2500 tCO<sub>2</sub>/day is given by (Williams 2001):

$$C_{SP} = 0.138(Q - 104.17)^{0.253} \tag{9}$$

**Sensitivity Analysis**

As there is considerable uncertainty in many of the assumptions for various technologies, H<sub>2</sub>Sim is designed to allow the user to easily change them. These changes in key component costs, fuel prices, and process efficiency have varying effects on hydrogen production costs.

H<sub>2</sub>Sim was built using Powersim Studio 2005, a dynamic simulation package. Powersim solves the model equations by integrating them with respect to some variable, normally time. H<sub>2</sub>Sim uses the capital cost as the dynamic variable, rather than time. The advantage of this choice is that the integration automatically produces a parameter study with respect to capital cost.

Since there is no relation between the capital cost and any of the other model parameters, the hydrogen production cost is directly proportional to the capital cost. Figure 6.3 and Table 6.4 illustrate the overall

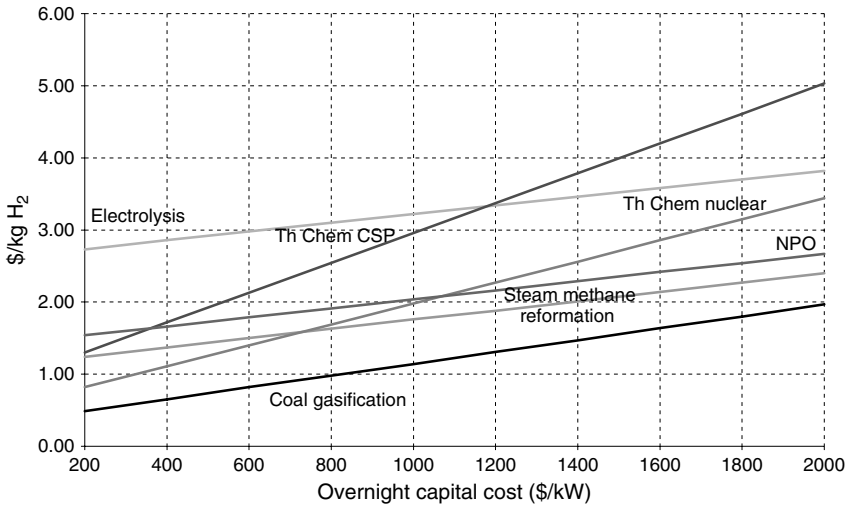


Figure 6.3. Capital cost sensitivity analysis.

Table 6.4. Hydrogen production costs (\$/kg): capital cost sensitivity

Capital (\$/kW)	Steam methane reformation	Coal gasification	Electrolysis <sup>1</sup>	Th Chem CSP	Th Chem nuclear	NPO
200	1.24	0.49	2.73	1.30	0.82	1.54
400	1.37	0.65	2.86	1.72	1.11	1.66
600	1.50	0.82	2.98	2.13	1.40	1.79
800	1.63	0.98	3.10	2.54	1.69	1.91
1000	1.76	1.14	3.22	2.96	1.98	2.04
1200	1.88	1.31	3.34	3.37	2.27	2.16
1400	2.01	1.47	3.46	3.79	2.56	2.29
1600	2.14	1.64	3.58	4.20	2.86	2.42
1800	2.27	1.80	3.70	4.61	3.15	2.54
2000	2.40	1.97	3.82	5.03	3.44	2.67

<sup>1</sup> Assumes use of electricity from natural gas combined cycle without transmission and distribution costs.

sensitivity of the results to assumptions about capital costs.<sup>14</sup> The relative slope of each technology's line indicates the CRF, which varies among the different technologies due to the different construction times, lifetimes, and capacity factors.

Ideally, future work on the model would investigate the connection between capital cost and hydrogen production rate. For example, the capital cost of steam methane reforming may be linked to the production rate as in Equation (2), which will provide a more complicated trade-off. This type of analysis is possible with H<sub>2</sub>Sim, but requires the user to adjust capital costs to reflect the unit size.

As an example of the type of analysis Figure 6.3 or Table 6.4 allows, consider the case of electrolysis. H<sub>2</sub>Sim initially assumes the capital costs of electrolysis will drop from about 600 \$/kW in 2003 to 300 \$/kW by 2020. This anticipated reduction in capital cost is projected to cut the cost to produce hydrogen from 2.98 to 2.80 \$/kg, about 18 cents/kg.

Figure 6.3 illustrates break-even points. For example, a SMR facility costing 600 \$/kW-H<sub>2</sub> is cost competitive with coal gasification facilities with capital costs above about 1400 \$/kW-H<sub>2</sub>, all else constant. Thermochemical CSP capital costs would have to fall below approximately 300 \$/kW to be competitive with the same SMR facility, again all else constant.

Figure 6.3 allows the user to answer questions regarding uncertain capital cost assumptions. For example, the capital cost of thermochemical nuclear is projected to be 669 \$/kW-H<sub>2</sub>. However, some suggest that this figure is on the optimistic side. It is possible that the actual capital

<sup>14</sup> This analysis option is included in H<sub>2</sub>Sim on the "Production, Capital Sensitivity" screen.

cost could be as high as two times that assumption. In that case, the production of hydrogen would cost close to 3\$/kg.

The base case results are sensitive to fuel prices and the overall efficiency of the process. Tables 6.5–6.9 show the relative sensitivity of SMR, coal gasification, electrolysis, NPO, and thermochemical nuclear to fuel costs and thermal efficiency.

SMR results are particularly sensitive to fuel price assumptions (Table 6.5). Natural gas prices historically have exhibited fairly strong price volatility. For example, while the EIA forecasts natural gas prices for utilities will be about 4.27\$/MBtu in 2010 and are expected to reach 5.20\$/MBtu in 2020, natural gas prices averaged much higher in 2004, at 6.11\$/MBtu (EIA 2006). For the default SMR efficiency of 70%, each \$1 rise in natural gas prices increases produced hydrogen costs by 0.16\$/kg. A doubling of predicted prices in 2010 would increase hydrogen production costs by 0.97\$/kg.

Table 6.6 summarizes the sensitivity of hydrogen from coal gasification to coal prices and overall process efficiency. The EIA forecasts coal prices of 1.25\$/MBtu by 2020. A doubling of these prices would increase hydrogen production costs by 0.21\$/kg. The results are not affected particularly by small changes in efficiency (+/–10%).

Hydrogen production costs from electrolysis are highly dependent on electricity prices (Table 6.7). For an electrolyzer efficiency of 70%, each 1-cent increase in electricity prices raises the produced hydrogen cost by 0.47\$/kg. At the average price paid for electricity by residential users in 2003 (8.97 cents/kWh<sup>15</sup>), it would cost about 4.44\$/kg to produce

Table 6.5. SMR fuel and efficiency sensitivity on hydrogen production costs (\$/kg)

Natural gas price (\$/MBtu)	Default efficiency	10% higher efficiency	10% lower efficiency
2	0.80	0.77	0.83
3	0.96	0.92	1.01
4	1.12	1.06	1.19
5	1.29	1.21	1.38
6	1.45	1.36	1.56
7	1.61	1.51	1.74
8	1.77	1.65	1.92
9	1.94	1.80	2.10
10	2.10	1.95	2.28
11	2.26	2.10	2.46
12	2.42	2.25	2.64

<sup>15</sup>EIA, Monthly Energy Review, January 2006.

Table 6.6. Coal gasification fuel price and efficiency sensitivity on hydrogen production costs (\$/kg)

Coal price (\$/MBtu)	Default efficiency	10% higher efficiency	10% lower efficiency
0.50	0.68	0.67	0.69
0.75	0.72	0.71	0.74
1.00	0.76	0.75	0.78
1.25	0.80	0.78	0.82
1.50	0.84	0.82	0.87
1.75	0.88	0.86	0.91
2.00	0.92	0.89	0.96
2.25	0.96	0.93	1.00
2.50	1.00	0.97	1.05
2.75	1.05	1.00	1.09
3.00	1.09	1.04	1.14

Table 6.7. Electrolysis electricity price and efficiency sensitivity on hydrogen production costs (\$/kg)

Electricity cost (cents/kWh)	Default efficiency	10% higher efficiency	10% lower efficiency
1	0.69	0.65	0.75
2	1.16	1.08	1.27
3	1.63	1.51	1.79
4	2.10	1.94	2.31
5	2.57	2.36	2.84
6	3.04	2.79	3.36
7	3.51	3.22	3.88
8	3.98	3.65	4.40
9	4.45	4.07	4.92
10	4.92	4.50	5.45
11	5.39	4.93	5.97
12	5.86	5.35	6.49
13	6.33	5.78	7.01
14	6.80	6.21	7.54
15	7.27	6.64	8.06

hydrogen based on the 2020 capital cost projection of 300 \$/kW-H<sub>2</sub>. Proponents of this option have argued it would make economic sense to produce hydrogen by electrolysis using cheap off-peak electricity. Using 1 cent/kWh electricity, hydrogen production costs are just 0.69\$/kg. However, there are two problems with this assumption. First, the large-scale use of off-peak electricity for hydrogen production would lead to increased prices for this electricity. Second, this off-peak electricity would only be available a few hours per day. If the electrolyzer was only used during these hours, the capacity factor would fall, increasing

hydrogen production prices. For example, whereas an electrolyzer operating 24 h per day with electricity costing 1 cent/kWh would produce hydrogen at 0.69 cents/kWh, operating the same electrolyzer just 6 h per day would increase the produced hydrogen cost to 1.37\$/kg. The results are quite sensitive to the efficiency of the process. For an electricity price of 5 cents/kWh, hydrogen production costs range from 2.36 to 2.84\$/kg for efficiencies of 10% higher or lower than the default assumption of 70%.

Hydrogen produced at refineries using the NPO process is quite sensitive to both the price of the crude oil and the overall efficiency of the process (Table 6.8). At 2006 prices of around 70\$/bbl for crude oil, improving the efficiency from 37 to 47% would drop the cost of hydrogen by 0.85\$/kg. At the default efficiency of 37%, each 5\$/bbl decrease in crude oil price reduces hydrogen production costs by 0.27\$/kg.

Hydrogen produced by a thermochemical nuclear process is sensitive to the price of uranium, as well as the efficiency of the process (Table 6.9). A 10% increase in efficiency at 2005 uranium prices of

Table 6.8. NPO fuel price and efficiency sensitivity on hydrogen production costs (\$/kg)

Crude oil price (\$/bbl)	Default efficiency	10% higher efficiency	10% lower efficiency
20	1.38	1.15	1.78
30	1.91	1.57	2.51
40	2.44	1.99	3.24
50	2.98	2.41	3.97
60	3.51	2.83	4.70
70	4.04	3.25	5.44
80	4.58	3.67	6.17
90	5.11	4.08	6.90
100	5.64	4.50	7.63

Table 6.9. Thermochemical nuclear uranium price and efficiency sensitivity on hydrogen production costs (\$/kg)

Uranium price (\$/MBtu)	Default efficiency	10% higher efficiency	10% lower efficiency
0.00	1.16	1.05	1.28
0.50	1.56	1.42	1.73
1.00	1.96	1.78	2.18
1.50	2.37	2.15	2.63
2.00	2.77	2.52	3.08
2.50	3.17	2.88	3.52
3.00	3.57	3.25	3.97

0.43\$/MBtu results in a 0.14\$/kg decrease in the price of hydrogen, while a 10% decrease in the efficiency results in a 0.17\$/kg increase in the price of hydrogen. At the assumed efficiency of 43%, an increase in the price of uranium of 0.50\$/MBtu results in an increase of approximately 0.40\$/kg of hydrogen.

Figures 6.5–6.7 graphically illustrate the sensitivity of the results to feedstock prices and capital costs. In each graph, the feedstock for one technology varies along the *x*-axis, while all other technologies are held constant. This allows one to see the feedstock prices at which other technologies become cost competitive. In addition, these results illustrate how sensitive the results are to assumptions about capital costs.

Figure 6.4 compares hydrogen production costs from SMR at various natural gas prices to the costs from the other technologies using the default assumptions. The graph illustrates the sensitivity of these results to capital cost assumptions by including lines indicating results for  $\pm 20\%$  of the default capital costs. This analysis shows that SMR is competitive with coal gasification (using the default assumptions) only if natural gas prices fall to 2\$/MBtu. Thermochemical nuclear competes with SMR for natural gas prices above 6.30\$/MBtu. Electrolysis does not become competitive with centralized SMR unless natural gas prices rise past 12\$/MBtu. Of course, as the default electrolysis option in H<sub>2</sub>Sim is natural gas combined cycle, higher fuel costs would increase significantly the cost of producing hydrogen. These results are not particularly sensitive to a  $\pm 20\%$  capital cost change for the SMR technology.

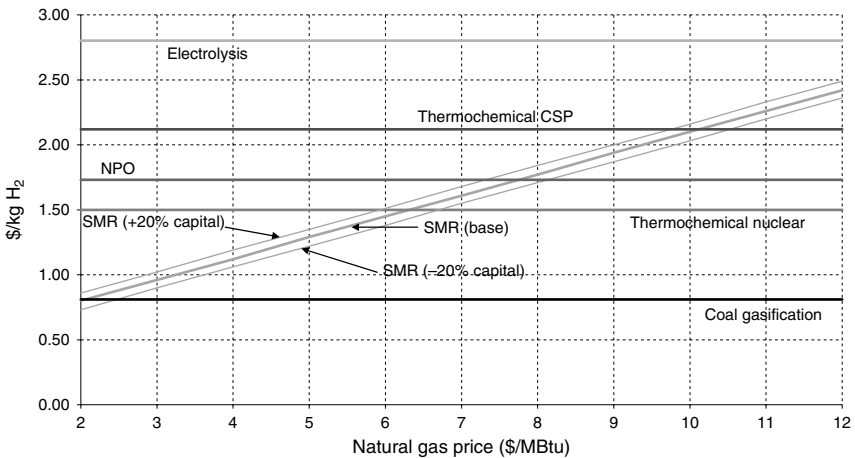


Figure 6.4. SMR sensitivity of natural gas prices on hydrogen production costs (\$/kg).

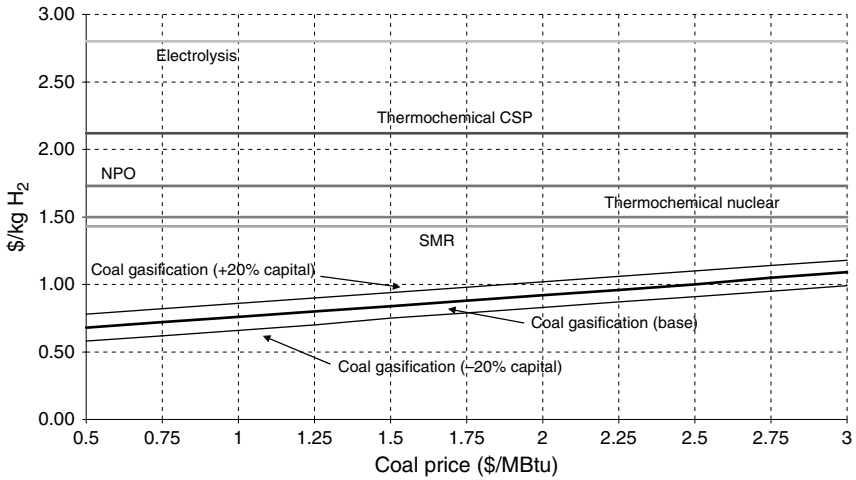


Figure 6.5. Coal gasification sensitivity to coal prices.

Figure 6.5 illustrates the sensitivity of the gasification results to coal prices. SMR becomes cost competitive with coal gasification only when coal prices exceed 3 \$/MBtu. This illustrates that because coal prices are so low, it will be difficult for any of the other technologies to compete.

Figure 6.6 illustrates the sensitivity of the NPO results to crude oil prices. Given the existing technology, crude oil prices would have to

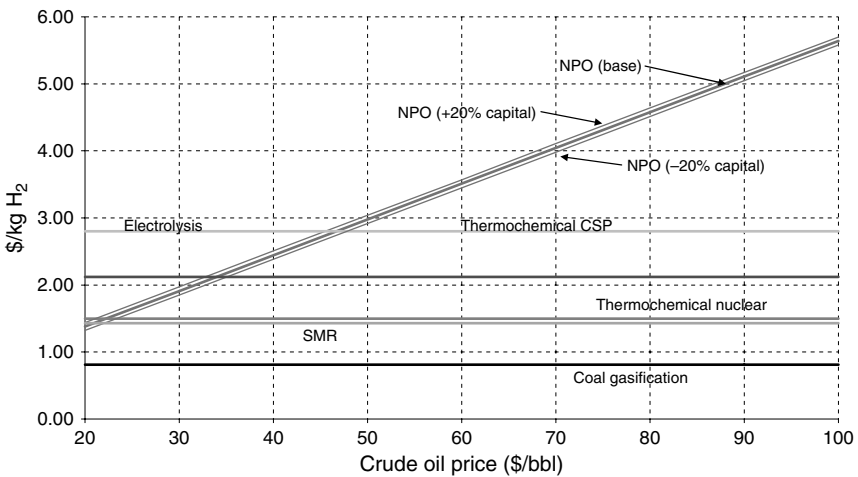


Figure 6.6. NPO sensitivity to crude oil prices.

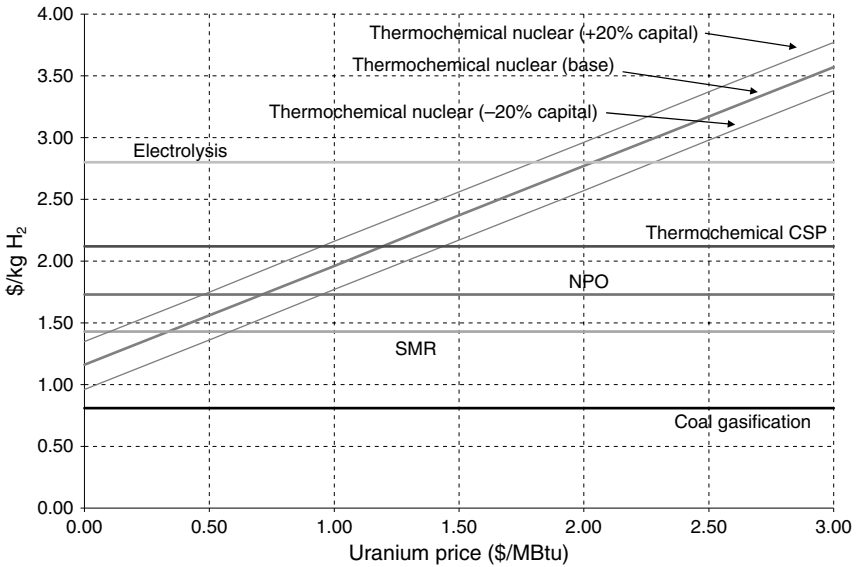


Figure 6.7. Thermochemical nuclear sensitivity to uranium prices.

drop below about 25\$/bbl to be competitive with SMR in 2020 and below 9\$/bbl to be competitive with coal gasification in 2020. Electrolysis competes with NPO at crude oil prices above 45\$/bbl.

Thermochemical nuclear production of hydrogen is sensitive to the price of uranium (Figure 6.7). At the 2005 price of uranium of 0.43 \$/MBtu, thermochemical nuclear is competitive with all hydrogen production options except coal gasification and SMR. The price of uranium would have to be below 0.35 \$/MBtu for thermochemical nuclear to become cost competitive with SMR, and there is no uranium price at which it is competitive with coal gasification. For every \$1 increase in the price of uranium, the cost of hydrogen increases by approximately 0.80 \$/kg. At a uranium price of 1.20 \$/MBtu, thermochemical nuclear no longer is competitive with any production option except electrolysis. Figure 6.7 indicates that increasing or decreasing the capital cost by 20% changes the results by 0.20 \$/kg.

### Carbon Emissions

One of the potential benefits of hydrogen is a decrease in carbon emissions, thought to be the leading anthropogenic contributor to global climate change. Conventional ICE vehicles emit approximately 1.04 tons of carbon annually, based on the default assumptions about efficiency

Table 6.10. Carbon capture and sequestration costs (\$/kg -H<sub>2</sub>)

	Reformation 70% reduction	Reformation 84% reduction	Gasification 87% reduction
Capital	0.01	0.08	0.06
Variable O&M	0.00	0.05	0.02
Fuel	0.04	0.04	0.01
Pipeline	0.02	0.03	0.05
Disposal well	0.03	0.03	0.02
Total	0.10	0.22	0.15

and miles driven.<sup>16</sup> Hydrogen vehicles offer the potential for zero carbon emissions if the hydrogen is produced using electrolysis from a non-carbon emitting source or a thermochemical process. Hydrogen produced using coal gasification or SMR will result in significant carbon emissions unless these options include some form of carbon capture and sequestration.

Table 6.10 summarizes estimated costs, in terms of \$/kg-H<sub>2</sub>, for carbon capture and sequestration. The results indicate that an 87% reduction in carbon emissions from coal gasification will add \$0.15 to each kilogram of hydrogen produced from this option. For natural gas reformation, estimates range from 0.10 to 0.22 \$/kg-H<sub>2</sub>, depending on the percentage of CO<sub>2</sub> removed. These results do not change the fundamental results, shown in Table 6.10. Coal gasification remains the cheapest option for producing hydrogen, even with 87% CO<sub>2</sub> capture and sequestration. There is, however, considerable uncertainty about sequestration possibilities. Ongoing demonstration projects should help establish the long-term viability of storing large amounts of carbon produced from the production of hydrogen.

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<sup>16</sup> Vehicle assumptions are discussed in Chapter 10.

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# Chapter 7

## Hydrogen Distribution

Once hydrogen is produced at a centralized facility, it must be delivered to the fueling station. Depending on the delivery method, there may be storage costs at both the production facility and fueling station. The delivery cost can be quite expensive, and may determine the overall viability of the hydrogen option. This section outlines the various options for distribution and how these options are included in H<sub>2</sub>Sim.

While several authors estimate the costs of hydrogen storage and transportation, few provide the formulas used to derive those costs. Simbeck and Chang (2002) of SFA Pacific report costs associated with the handling and storage of compressed gas and liquefied hydrogen as well as the costs associated with three of the most likely hydrogen transportation options: pipeline, compressed gas tube trailers via truck, and liquefied hydrogen cryogenic tanks via truck. They estimate these costs for several different pathways, including production, storage, transportation, and dispensation of hydrogen as well as the option of on-site, or forecourt, production. Their analysis reports the results for a narrow range of assumptions regarding compression pressures, production rates, and transportation distances and options. While their analysis is based on a simulation model that allows the user to vary key assumptions, the model is proprietary and their report provides limited information for a few key assumptions.

A 2002 analysis by Thomas et al. from Directed Technologies Inc. focuses on the cost of a hydrogen infrastructure compared to the costs associated with maintaining the current gasoline infrastructure. Their analysis focuses on three main fueling options: gasoline, methanol, and hydrogen. The team from Directed Technologies examined the possibilities of on-site steam methane reformation of natural gas using the existing infrastructure as well as on-site hydrogen production and the reformation of methanol. They conclude that the cost of building and supporting an infrastructure that would allow for the on-site reformation of natural gas for the production of hydrogen was significantly

less expensive than the costs associated with maintaining the current gasoline infrastructure.

Thomas et al. (2001) also discuss the costs associated with the compression of hydrogen, a major part of the fueling station cost. The analysis includes formulas used to determine the energy and power requirements of compression as well as a comparison of different storage tank options involving construction materials and compression levels. They consider both cascade compressors, which compress hydrogen in stages to its final pressure, and booster compressors, which dispense gas that is at a low compression level into the fuel cell vehicle and then further compress during dispensation. While their analysis provides a lot of detail about the costs of compression and storage at the fueling station, it gives limited detail regarding expenses associated with storage at the production site and transportation to fueling stations.

In a 1998 report published by the National Renewable Energy Laboratory, Wade Amos examines possible storage and transportation options for hydrogen. Amos presents a detailed economic analysis of the capital and operating costs for currently available technologies. The analysis includes four potential storage options: compressed gas aboveground, compressed gas underground, liquefied, and metal hydride storage. This storage is presumed to occur at the site of centralized hydrogen production. Additionally, Amos examined eight options for hydrogen transport: truck and rail transport for each of the three phases of hydrogen (compressed gas, liquid, and metal hydride), ship transport for liquefied hydrogen, and pipeline transport of gaseous hydrogen. For each, Amos presents results for a base case scenario, with assumption specifications and a range of production levels, storage times, and transportation distances. Furthermore, he presents the equations and sizing factors used to determine the costs associated with each option. This allows for an easy reconstruction and the potential to vary some of the key assumptions.

The storage and transportation cost results from Amos' analysis are compared to the results from Simbeck and Chang's analysis in Table 7.1. This comparison assumes a production rate of 150 000 kg/day (enough to serve approximately 225 000 vehicles), storage time of 12 h, compression from 1 MPa (145 psi) to 21.5 MPa (3000 psi) and a transport distance of 150 km. A transport pressure of 3000 psi is lower than the expected 5000–10 000 psi range of pressures for use in vehicles.

The SFA results are significantly higher than those presented by Amos, and highlight the huge degree of uncertainty associated with various transport options. For example, whereas Amos estimates hydrogen could be delivered for about 0.10 \$/kg by pipeline, the SFA study estimates costs of 2.94 \$/kg. They do follow a similar pattern, with

Table 7.1. SFA Pacific and Amos transportation results comparison (\$/kg)

	SFA	Amos
Production rate = 150 000 kg/day		
Storage time = 12 h		
Compression from 1 MPa–21.5 MPa		
Transport distance = 150 km		
<b>Storage</b>		
Compressed gas	0.44	0.07
Liquefied	1.31	0.10
<b>Transportation</b>		
Pipeline	2.94	0.10
GH truck	2.09	1.32
LH truck	0.18	0.06

Source: Simbeck and Chang (2002), and Amos (1998).

compressed gas storage and liquefied hydrogen truck transport the least expensive options for these parameters. In the case of pipeline transportation, SFA assumes that there is a factor of four penalty in building the pipeline infrastructure. Rather than transporting the hydrogen through a single pipeline, which Amos assumes, Simbeck and Chang present costs associated with transporting hydrogen from one site in four different directions. Neither Amos nor Simbeck and Chang account for capital financing costs in their analyses. In addition to the options summarized in Table 7.1, Amos examines storage and transportation of metal hydrides, which are not included in Simbeck and Chang's analysis.

This section outlines the equations used in the model to determine the costs associated with on-site hydrogen storage and transportation. While several of these equations are from the Amos study, others were derived by the modeling team or other sources, as indicated. When using Amos' work, we included the cost of capital financing, which Amos did not.

### Storage

Unless hydrogen is produced on demand, such as via electrolysis at the fueling station, it will require storage. Hydrogen can be stored in three different phases: compressed gas, liquefied, and within metal hydrides. Each option has different costs associated with transforming the hydrogen from its production state to its storage state as well as storage

maintenance. The total cost of storage is based on two primary factors: production rate and storage time. Additionally, the storage time is partly a function of the production rate and is also a function of the transportation distance. When a production facility produces a low quantity of hydrogen, the hydrogen is likely to be stored for a longer period of time at the production facility before the transportation unit is full. This section summarizes assumptions and formulas used to derive the costs of storage for each of the three phases of hydrogen.

### Compressed gas

Compressed gas storage of hydrogen can take place aboveground in tanks or belowground in some type of cavern. Both gaseous storage options require hydrogen compression, and thus include the cost of the compressor and the energy associated with compression. Amos provides base case assumptions as well as sizing factors for the compressor cost. These assumptions are summarized in Table 7.2.

These variables are used to determine costs associated with hydrogen compression for both types of gaseous storage using a multistage compressor. The energy required (kW) for isothermal compression is a function of the production rate as well as the inlet and outlet pressures

$$W = \left( \frac{mRT}{\eta} \right) \ln \left( \frac{P_{\text{Inlet}}}{DP} \right) \quad (1)$$

where  $m$  is the mass flow rate (g/h);  $R$  is hydrogen gas constant (J/g K);  $T$  is temperature (K);  $\eta$  is efficiency (initially 80%);  $P_{\text{Inlet}}$  is inlet pressure (MPa);  $DP$  is the delivery pressure (MPa).

The total capital cost of the compressor is determined using sizing factors to adjust from the baseline size (4000 kW) and cost (1000 \$/kW) provided by Amos (1998). Specifically, the total capital cost of the

Table 7.2. Compressor assumptions

Description	Unit	Assumption
Base case compressor cost	\$/kW	1000
Base case compressor size	kW	4000
Base case compressor pressure	MPa	20
Compressor sizing exponent		0.8
Compressor pressure factor		0.18
Compressor power requirement	kWh/kg	2.205
Compressor cooling water requirement	gal/kg	13.23

Source: Amos (1998).

compressor ( $C_{Cap}$ ) is determined partly by the energy and cooling water requirements

$$C_{Cap} = CC \times CS \left( \frac{E}{CS} \right)^{CompExp} \left( \frac{P}{P_0} \right)^{CPExp} \tag{2}$$

where  $CC$  is the base compressor cost (\$/kW);  $CS$  is base compressor size (kW);  $E$  is compressor power (kW);  $CompExp$  is compressor sizing exponent;  $P$  is operating pressure (MPa);  $CPExp$  is compressor pressure factor;  $P_0$  is the baseline operating pressure (MPa).

The variable costs for storage include the energy and cooling water costs; both are a function of the desired level of pressurization, compressor efficiency, and electricity cost.

In addition to the compressor capital and variable costs, each type of compressed gas storage has other costs unique to that storage type.

*Aboveground pressurized tanks*

Aboveground storage of compressed gas requires high-pressure storage tanks. Using a baseline tank size of approximately 225 kg and cost of approximately 1300 \$/kg, the capital cost of the tank is determined using a sizing factor, given by Amos (1998) and based on a baseline operating pressure of 20 MPa (Table 7.3).

Total capital costs for tank storage are given by

$$T_{Cap} = (TC \times TS) \left( \frac{SC \frac{TP}{P}}{TS} \right)^{0.75} \left( \frac{P}{TP_0} \right)^{0.44} \tag{3}$$

where  $TC$  is base tank cost (\$/kW);  $TS$  is base tank capacity (kg);  $SC$  is storage capacity (kg);  $TP_0$  is baseline tank pressure (MPa); and  $P$  is the operating pressure (MPa).

Amos assumes the capital costs are divided evenly over the life of the unit. This ignores financing costs.  $H_2Sim$  treats the capital costs

Table 7.3. Aboveground compressed gas storage assumptions

Description	Unit	Assumption
Base case tank cost	\$/kg	1323
Base case tank capacity	kg	226.76
Base case tank pressure	MPa	20
Tank sizing exponent		0.75
Tank pressure factor		0.44

Source: Amos (1998).

associated with storage the same way it does capital costs associated with production, and includes taxes and financing costs. The total cost of aboveground compressed gas storage per kilogram of hydrogen is given by the sum of the annual cost components (capital, energy, and cooling water) distributed over the total annual production.

#### *Underground pressurized caverns*

Underground storage provides an alternative option for compressed gas storage. However, this option is available in very limited locations, as it requires the existence of some type of cavern. The costs of underground storage are determined by the cost of hydrogen compression as well as the cost of the cavern. Amos assumes a capital storage cost of 8.82 \$/kg of storage capacity, regardless of cavern size. Therefore, storage costs are a function of facility size and storage pressure

$$CV_{\text{Cap}} = UC \left( CS \left( \frac{TP}{P} \right) \right) \quad (4)$$

where UC is the underground cavern cost (\$/kg); CS is cavern capacity (kg); TP is baseline storage tank pressure (MPa); and  $P$  is the operating pressure (MPa).

Again, the total capital cost is determined by the sum of the compressor cost and the underground storage cavern cost. The calculation for the total annual cost of the depreciating capital is found using the total capital cost and accounting for financing with the capital recovery factor. The total cost per kilogram for gaseous underground storage is determined by the total capital and variable costs divided over the annual production of the hydrogen facility.

One of the biggest problems with hydrogen stored as a compressed gas is its very low volumetric density and the resulting need for large storage facilities. Liquefied hydrogen provides one solution to this problem.

#### *Liquefied*

Liquefied hydrogen can be stored in smaller spaces than compressed gas hydrogen. However, it requires very low temperatures to prevent boil-off, which occurs when hydrogen evaporates into a gaseous state. The costs associated with liquefied hydrogen storage include liquefaction, the capital costs of the storage tanks, and operation and maintenance. The power requirements for liquefaction are significant; Amos assumes 9.92 kWh/kg. The default assumptions in H<sub>2</sub>Sim for determining liquefied storage costs are summarized in Table 7.4.

Table 7.4. Liquefied hydrogen storage base case assumptions

Description	Unit	Assumption
Base case liquefier cost	\$/ (kg/h)	44 100
Base case liquefier size	kg/h	454
Liquefier sizing exponent		0.65
Liquefier power requirement	kWh/kg	9.92
Liquefier cooling water requirement	gal/kg	165
Base case dewar cost	\$/kg	441
Base case dewar capacity	kg	221
Dewar sizing exponent		0.70
Boil-off rate	%/day	0.10

Source: Amos (1998).

The costs associated with liquefied hydrogen storage are determined by the production rate, storage time, and boil-off rate. Equation (5) is used to determine the net production accounting for the losses incurred from the boil-off effect

$$F_{\text{BOR}} = F(1 + (1 - e^{(-\text{BOR} \times \text{ST})})) \quad (5)$$

where  $F$  is the production rate (kg/h); BOR is boil-off rate (%/day); and ST is the storage time (days).

In addition to the variable energy and cooling water costs, the total cost of liquefied hydrogen storage includes the capital costs of the liquefier as well as the dewars, or liquefied hydrogen storage tanks. The cost of the liquefier varies with the production rate and uses a sizing exponent to determine the capital cost

$$L_{\text{Cap}} = \text{LC} \times \text{LS} \left( \frac{F_{\text{BOR}}}{\text{LS}} \right)^{0.65} \quad (6)$$

where LC is the base liquefier cost (\$/[kg/h]); LS is base liquefier size (kg/h); and  $F_{\text{BOR}}$  is the production rate including boil-off (kg/h).

The capital cost of the dewar is also determined using a sizing exponent and the ratio of the base cost and size to the actual storage capacity of the dewar

$$D_{\text{Cap}} = \text{DC} \times \text{DS} \left( \frac{\text{SC}}{\text{DS}} \right)^{0.70} \quad (7)$$

where DC is the base dewar cost (\$); DS is base dewar size (kg); and SC is the storage capacity (kg).

The total capital cost must then be adjusted for depreciation to determine the annual capital cost using the CRF. The total cost of liquefied hydrogen storage is the sum of the liquefier, dewar, energy, and cooling water costs.

An alternative to gaseous and liquefied storage of hydrogen is storage as a solid, in the form of a metal hydride.

### *Metal hydride*

Metal hydrides provide a solid-state storage option in which hydrogen is absorbed into the lattice of the metal. This option for storage is probably the least understood at this time, but in many ways could prove to be the most appealing. For example, it might someday be possible to build the vehicle frame out of a material that also stores the hydrogen.

The cost of metal hydride storage includes cooling the water, heating, equipment necessary to create the hydrogen absorption and release, and the metal hydride itself. Table 7.5 provides the base case assumptions used in determining the total cost of metal hydride hydrogen storage.

Storing hydrogen in metal hydride form requires cooling and heating. Cooling is required to absorb hydrogen into the metal; steam heat is needed to release the hydrogen. Both costs are included in Amos' analysis. The annual cost associated with this energy consumption is determined by the assumed heating requirement, the energy cost, and the annual production rate. Similarly, the annual cost for cooling water is calculated based on the assumed water requirement, cost of water, and production rate.

Amos assumes that the capital cost is independent of facility storage size. This eliminates the need for a sizing exponent, which had been required to determine the costs of gaseous and liquefied hydrogen storage. Annual capital costs again are found by multiplying the total financed costs by the capital recovery factor. The total cost of metal hydride storage is the sum of the annual capital, steam, and cooling water costs distributed over the annual production rate.

Table 7.5. Metal hydride storage base case assumptions

Description	Unit	Assumption
Metal hydride cost	\$/kg	2205
Metal hydride heat requirement	kWh/kg	6.46
Metal hydride cooling water requirement	gal/kg	55

Source: Amos (1998).

In summary, the three main storage options for hydrogen are: compressed gaseous storage, either aboveground or belowground; liquefied storage in tanks; and metal hydride storage. As mentioned earlier, storage may take place in more than one setting. For certain production processes, for example, it may make sense to store the hydrogen at the production site prior to transport. Additional storage may be needed at the fueling site. It also may be possible to avoid storage at the production site, such as when gas is shipped via pipelines.

### Transportation

Hydrogen produced at a centralized facility must be transported to a fueling station. Hydrogen can be transported in many ways, ranging from gaseous or liquefied truck transport to large-scale pipelines. Getting hydrogen to the end-use site also may require multiple modes of transport, including large, regional pipelines that connect to either smaller, local pipelines or to trucks, ships, or rail cars.

H<sub>2</sub>Sim provides various ways to transport hydrogen, including likely storage options. The relevant assumptions associated with each of these nine transport options are summarized in Table 7.6. As an example, Option 1 uses underground, gaseous storage of hydrogen in caverns. Large pipelines (9–14 in.) carry the gaseous hydrogen to a series of smaller, local pipelines (2–4 in.), which deliver the hydrogen to a fueling station that includes gaseous storage tanks.

Some of the assumptions used for truck and rail transport remain constant for gaseous, liquefied, and metal hydride transport (Table 7.7).

Table 7.6. Distribution options in H<sub>2</sub>Sim

Option	Storage	Transport 1	Transport 2	Fueling station
1	Underground, Gaseous	Pipeline, Large	Pipeline, Local	Gaseous
2	Tanks, Gaseous	Pipeline, Large	Pipeline, Local	Gaseous
3	Tanks, Gaseous	Truck, Gaseous	None	Gaseous
4	Tanks, Liquefied	Truck, Liquid	None	Liquefied
5	Tanks, Gaseous	Pipeline, Large	Truck, Gaseous	Gaseous
6	Metal hydride	Truck, Metal hydride	None	Metal hydride
7	Tanks, Gaseous	Rail, Gaseous	Truck, Gaseous	Gaseous
8	Tanks, Liquefied	Ship, Liquid	Truck, Liquid	Gaseous
9	Tanks, Liquefied	Rail, Liquid	Truck, Liquid	Gaseous

Table 7.7. Truck and rail transport assumptions

Description	Unit	Assumption
Truck undercarriage cost	\$	60 000
Truck cab cost	\$	90 000
Truck average mileage	mi/gal	6
Truck average speed	mi/h	50
Truck load/Unload time	h	2
Truck daily availability	h/day	24
Truck trailer depreciation time	yr	6
Truck tractor depreciation time	yr	4
Truck driver wages and benefits	\$/h	28.75
Truck driver daily availability	h/day	12
Diesel price	\$/gal	1
Rail undercarriage cost	\$	100 000
Rail freight cost	\$	400
Rail average speed	mi/h	25
Rail load/Unload time	h	24
Rail availability	h/day	24

Source: Amos (1998).

### Compressed gas

As a compressed gas, hydrogen can be transported by truck, ship, rail, or pipeline, or some combination of the above.

#### Truck

The total cost of truck transport includes the capital cost of the trucks, compressed gas handling tubes, and the labor and fuel costs associated with driving the truck from the production site to the fueling station. The total annual capital cost is based, in large part, on the number of trucks necessary to transport the hydrogen, which is determined by the transport rate, truck capacity, and truck transport characteristics. Initially, the gaseous hydrogen truck tube cost is assumed to be \$100 000 and the capacity is assumed to be 180 kg. The low capacity is a result of the necessary weight of the tube trailers and the low density of compressed hydrogen. This low density results in a large number of trips and ultimately a large quantity of trucks to transport seemingly small quantities of hydrogen. Based on the required number of trips and trucks, determined by the annual production, truck capacity, distance, and transport speed, the annual capital costs are

$$\begin{aligned}
 CC_{\text{Annual}} = & (T(TC_{\text{GH}_2} + TC_{\text{Under}})\text{TrailerCRF}) \\
 & + ((TTC_{\text{Cab}})\text{TractorCRF})
 \end{aligned}
 \tag{8}$$

where  $T$  is the required number of trucks;  $TC_{GH_2}$  is gaseous hydrogen tube cost (\$);  $TC_{Under}$  is truck undercarriage cost (\$);  $TrailerCRF$  is trailer capital recovery factor (%);  $TC_{Cab}$  is truck cab cost (\$); and  $TractorCRF$  is the cab capital recovery factor (%).

In addition to the capital costs associated with truck transport of gaseous hydrogen, annual fuel costs are based on the number of trips required, the travel distance, and the price of diesel. The final cost that is included in the total transportation cost is the labor cost

$$C_{Labor} = WTR \left( \left( \frac{TW}{TS} \right) + TL \right) \quad (9)$$

where  $TR$  is the annual trips;  $TW$  is two-way transport distance (miles);  $TS$  is average truck speed (miles/h);  $TL$  is truck load/unload time (h);  $W$  is the driver wage and benefits (\$/h).

In summary, the total cost per kilogram for transporting hydrogen is the total annual capital, fuel, and labor costs, divided by the annual production rate.

### Rail

The total cost of rail transport is determined by two costs: capital and freight, which includes such variables as the rail conductor wage. The default assumption is that each railcar gaseous storage container costs \$200 000 and has a capacity of 450 kg of hydrogen. An important variable is the required number of trips, which is a function of the annual production rate and the capacity of the hydrogen railcars. The required number of trips then is used to determine the total delivery time, number of railcars, and ultimately the total capital cost. Total delivery time, which includes the return time of the railcars, is found using

$$\text{Time} = TR \left( \left( \frac{TW}{RS} \right) + RL \right) \quad (10)$$

where  $TR$  is trips required annually (#/yr);  $TW$  is two-way delivery distance (miles);  $RS$  is average rail speed (miles/h); and  $RL$  is the rail load/unload time (h).

This delivery time is used to determine the required number of railcars and the annual capital cost accounting for financing using the CRF:

$$\text{DepCost} = \left( \frac{\text{Time}}{RA \times \text{OpDays}} \right) (RC_{GH_2} + RC_{Under}) \text{RailCRF} \quad (11)$$

where  $\text{Time}$  is the total delivery time (h/yr);  $RA$  is rail availability (h/day);  $\text{OpDays}$  is days of operation (days/yr);  $RC_{GH_2}$  is gaseous

hydrogen railcar container cost (\$); and  $RC_{\text{Under}}$  is the railcar capital recovery factor (%).

In summary, the total cost for rail transport of gaseous hydrogen is found by combining annual capital costs for the rail cars and the per load freight costs.

### *Liquefied*

Liquefied hydrogen requires less volume than gaseous hydrogen, but very low temperatures are necessary to avoid boil-off, or the evaporation of hydrogen. The formulas used to determine the cost of liquefied hydrogen transport are very similar to the cost of transporting gaseous hydrogen via truck or rail, except for the need to account for the boil-off of liquefied hydrogen. The differences in the methodologies and the option of ship transport are explained in this section.

### *Truck*

Because of the nature of liquefied hydrogen, the capital cost of a transport unit is higher than the cost of a gaseous transport unit, but the capacity is also higher. Initially, the cost is assumed to be \$350 000 per truck with a capacity of 4082 kg. Substituting the liquefied hydrogen truck capacity for the gaseous hydrogen truck capacity determines the number of trips required to transport the hydrogen and thus the number of trucks and the vehicles' total capital cost. Approximately 3%/day of the liquefied hydrogen is lost due to boil-off. Total delivered hydrogen is given by

$$\text{Delivered} = AP \times e^{\left(-\text{TruckBOR} \left(\frac{D}{TS} L\right)\right)} \quad (12)$$

where AP is the annual production of hydrogen (kg/yr); TruckBOR is truck boil-off rate (%/day);  $D$  is one-way transport distance (miles); and TS is the average truck speed (miles/h).

With all other formulas remaining the same as those that determine compressed gas truck transport costs, the total delivered cost per kilogram is found using the recalculated capital, fuel, and labor costs and dividing those costs by the delivered quantity of hydrogen, accounting for the boil-off.

### *Rail*

The transportation cost of liquefied hydrogen via rail is found in much the same way as the cost of rail transport of compressed gas, but the

capacity size is 9070 kg of hydrogen. For rail transport the total boil-off effect is greater because of the increased transport time. The delivered quantity of hydrogen accounting for boil-off is calculated using:

$$\text{Delivered} = AP \times e^{\left(-\text{RailBOR} \left( \frac{D}{RS} \right) \right)} \quad (13)$$

where  $D$  is the one-way transport distance (miles);  $RS$  is average rail speed (miles/h);  $AP$  is annual production of hydrogen; and  $\text{RailBOR}$  is rail boil-off rate (%/day).

The total cost per kilogram of liquefied hydrogen transported by rail can be determined in the same way that it is for compressed gas and metal hydrides, while accounting for the losses due to boil-off.

### Ship

Ship transport is an option that exists only for liquefied hydrogen. Table 7.8 summarizes the initial assumptions used in determining the costs of ship transport.

The cost of ship transport has two components: capital and freight. The delivered cost must be adjusted for the boil-off that occurs during transport. The delivered hydrogen is then found using the equation:

$$\text{Delivered} = AP \times e^{\left(-\text{ShipBOR} \left( \frac{D}{SS} \right) \right)} \quad (14)$$

where  $D$  is the one-way travel distance (miles);  $SS$  is average ship speed (miles/h);  $AP$  is annual production of hydrogen; and  $\text{ShipBOR}$  is the ship boil-off rate (%/day).

The capital cost is a function of production level, ship capacity, load time, and freight cost. Freight cost is given by

$$\text{FC} = \left( \frac{AP}{SS_{\text{LH2}}} \right) \text{SF} \times 2 \quad (15)$$

Table 7.8. Ship transport assumptions

Description	Unit	Assumption
Liquefied ship cost	\$	350 000
Liquefied ship capacity	kg	4082
Ship speed	mi/h	10
Ship load/Unload time	h	48
Ship availability	h/day	24
Ship freight	\$	3000
Ship boil-off rate	%/day	0.3

Source: Amos (1998).

where AP is the annual production of hydrogen (kg/yr);  $SS_{LH_2}$  is liquefied hydrogen ship capacity (kg); and SF is the ship freight cost (\$).

Therefore, the total cost per kilogram of transporting liquefied hydrogen by ship can be found in the same way that other transportation costs are determined, dividing the annual cost over the annual production while accounting for boil-off.

### *Metal hydride*

Metal hydrides provide a solid-state transport option for hydrogen and can be transported either by trucks or rail. The formulas used to determine these costs are very similar to those used to determine the cost of gaseous hydrogen transport. The difference between the cost of transporting gaseous hydrogen and metal hydrides lies in the cost of the vehicle as determined in terms of dollars per kilogram of hydrogen transported rather than one absolute cost.

### *Truck*

The capital cost associated with truck transport uses two assumptions. The estimated initial capital cost is 2200 \$/kg (1000 \$/lb) of hydrogen for a truck capacity of 450 kg. By using the size of the metal hydride truck and the total transport distance, the necessary number of trips and the required number of trucks for metal hydride transport can be calculated. The formula used to determine the total capital cost, however, changes due to the units used for the cost of the metal hydride truck. The annual capital cost is calculated by:

$$\begin{aligned} \text{DepCost} = & ((T((TC_{MH_2} TS_{MH_2}) + TC_{\text{Under}}))\text{TrailerCRF}) \\ & + (TTC_{\text{Cab}}\text{TractorCRF}) \end{aligned} \quad (16)$$

where  $T$  is the metal hydride required number of trucks;  $TC_{MH_2}$  is metal hydride truck container cost (\$/kg);  $TS_{MH_2}$  is metal hydride truck container capacity (kg);  $TC_{\text{Under}}$  is truck undercarriage cost (\$); TrailerCRF is truck trailer capital recovery factor (%);  $TC_{\text{Cab}}$  is truck cab cost (\$); and TractorCRF is the truck tractor capital recovery factor (%).

The fuel and labor costs of metal hydride truck transport are found using the same calculations as those used for gaseous hydrogen transport, adjusting for the number of trips necessary based on the capacities of the vehicles. Therefore, total cost is found in the same way, with the annual capital cost adjusted for the unit differences.

### Rail

Costs of rail transport of metal hydrides are determined in much the same way as rail transport of gaseous hydrogen. The only difference, again, is that the unit in which the railcar cost is measured is dollars per kilogram, changing the capital cost calculation in the same way that the capital cost was calculated for truck transport.

Using the metal hydride railcar capacity, initially assumed to be 900 kg, and the production rate determines the required number of trips annually. The formula used to determine total delivery time remains the same, and the annual capital cost is calculated using

$$\text{DepCost} = \left( \frac{\text{Time}}{\text{RA} \times \text{OpDays}} \right) ((\text{RC}_{\text{MH}_2} \text{RS}_{\text{MH}_2}) + \text{RC}_{\text{Under}}) \text{RailCRF} \quad (17)$$

where Time is total delivery time (h/yr); RA is rail availability (h/day); OpDays is days of operation (days/yr);  $\text{RC}_{\text{MH}_2}$  is metal hydride railcar cost (\$/kg);  $\text{RS}_{\text{MH}_2}$  is metal hydride railcar capacity (kg);  $\text{RC}_{\text{Under}}$  is railcar undercarriage cost (\$); and RailCRF is the railcar capital recovery factor (%).

Initially, the cost of the metal hydride rail car is assumed to be 2200 \$/kg of hydrogen. Therefore, the total annual cost is the sum of the freight cost, found in the same way as other rail transport options. Capital cost can be distributed through the hydrogen produced annually.

### Pipeline

Gaseous hydrogen may be carried widely by pipelines. Pipeline transportation costs are divided into three components: energy, compressor capital cost, and pipeline capital cost. Pipeline transportation costs are affected by the pipeline characteristics, compressor characteristics, production rate, transportation distance, and hydrogen properties. Unlike other transportation options, the methodology used in H<sub>2</sub>Sim to determine pipeline transportation costs is not drawn from Amos' (1998) work, as it offers users considerably more options than just a single pipeline. The basic assumptions regarding the pipeline and compressor characteristics are summarized in Table 7.9.

Hydrogen pipelines may follow a pattern similar to that illustrated in Figure 7.1. One large pipeline (initially 12 in. in diameter) is used to transport the hydrogen from the production facility to the city gate and around the delivery area, and multiple small pipelines (initially 3 in. in diameter) are used for local delivery. Alternatively, the larger pipeline may be a long, straight line, branching out to either smaller, local pipelines or connecting to truck, rail, or ship. Figure 7.2 illustrates the case of large pipelines and local truck transport. In the case of smaller

Table 7.9. Pipeline and compressor characteristic assumptions

Variable	Unit	Assumption
Pipeline temperature	K	283
Pipeline friction factor		0.005
Hydrogen gas constant	J/kg*K	4.124
Compressor temperature	K	300
Compressor baseline cost	\$/kW	1000
Compressor baseline size	kW	4000
Compressor baseline pressure	MPa	20
Compressor sizing exponent		0.80
Compressor pressure factor		0.18

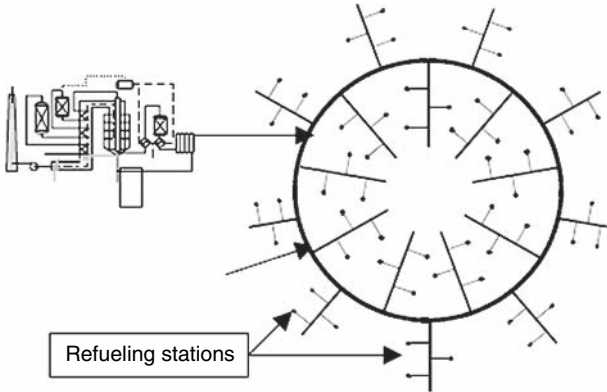


Figure 7.1. Hydrogen pipeline distribution schematic.  
(Source: Mintz et al. 2002.)

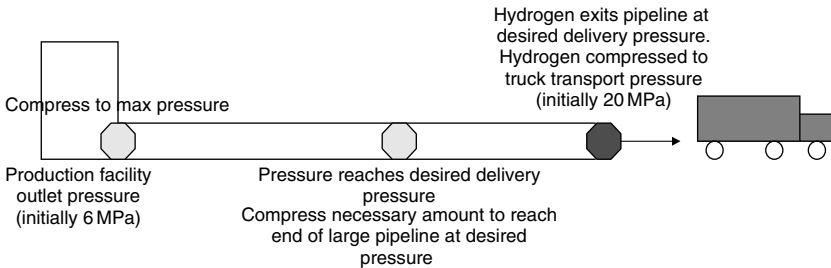


Figure 7.2. Large pipelines and local truck transports.

pipelines, H<sub>2</sub>Sim allows the user to set the number of local pipelines that come from the large pipeline. Doing this will determine automatically the flow rate through the local pipelines, using the total flow rate set by the user.

How many compressors will be needed along the pipeline is a function of several variables, including output pressure of the production option, the desired delivery pressure, maximum allowed pipe pressure, and pipeline length. Whether compressors are required in both the large and small pipelines depends on the delivery distance and pressure.

Pipeline transport requires a number of compressors; the first is located at the production site. Depending on the overall pipeline distance, compressors are placed throughout the large pipeline to compress the hydrogen along the way and deliver it at the desired pressure (initially assumed to be 2MPa) to the local pipelines. The hydrogen is compressed to the maximum pressure allowed in the pipeline (initially 6.7MPa [1000 psi]) unless  $P_{Inlet}$  (Equation 17) calculates that a lower pressure is required for delivery. Compressors are placed throughout the pipeline whenever the pipeline pressure falls below the desired delivery pressure. The necessary inlet pressure (MPa) to reach the desired outlet pressure is determined using the equation

$$P_{Inlet} = \frac{\sqrt{\left(\frac{4 \times FF \times D \times Flux^2 \times RH_2 \times T}{PD}\right) + DP^2}}{1\,000\,000} \quad (18)$$

where FF is the friction factor;  $D$  is transport distance (m); Flux is hydrogen flux through pipeline (kg/m<sup>2</sup>s); RH<sub>2</sub> is hydrogen gas constant (N m/kg K);  $T$  is temperature (K); PD is pipe diameter (m); and DP is the delivery pressure (Pa).

Using Equation (17), solving for the distance, and assuming  $P_{Inlet}$  is equal to the maximum allowed pressure of the pipeline, H<sub>2</sub>Sim calculates the distance before a new compressor is needed based on the desired delivery pressure. At this point a new compressor is added, which compresses the hydrogen to either the maximum pressure or the necessary pressure for the remainder of the transportation distance, determined by  $P_{Inlet}$ . This process is continued so that the final compressor will likely be smaller and only compress the hydrogen to the necessary pressure to result in the desired delivery pressure at the end of the large pipeline. In addition to the last compressor being smaller, the first compressor is also likely to be smaller, as the necessary compression is determined by the pressure of the hydrogen after production. For example, some production options release the hydrogen at a pressure of 6MPa. In some cases this will be enough pressure to travel the entire transportation distance. If not, the first compressor will only

be required to compress the hydrogen from 6 MPa to the maximum allowed pressure.

At the end of the large pipeline there is one more compressor, which compresses the hydrogen to the level required for local transportation. For the case of local pipeline distribution, this pressure loss is the difference between  $P_{Inlet}$ , calculated for the characteristics of the local pipeline, and the desired delivery pressure. If  $P_{Inlet}$  for local delivery is greater than the maximum pressure allowed in local pipelines (initially 6.7 MPa), there are compressors placed along the pipeline in the same fashion as the large pipeline. For the case of local transport by trucks, the compressors located at the end of the pipeline must be large enough to compress the hydrogen to the desired truck delivery pressure, initially assumed to be 20 MPa.

Once the number of compressors is determined, the work requirement (kW) for these compressors is found using Equation (10). This work requirement, or necessary compressor size, is used to determine the total energy requirement for the compressor, based on the capacity factor. It also is used to determine the capital cost of the compressor using the same method as the compressors in hydrogen storage.

In addition to the capital cost of the compressors, H<sub>2</sub>Sim calculates the capital cost of the pipelines. This is determined by the diameter and length of the pipeline. The diameter of the pipeline can be set by the user or determined by the model based on the flow rate. Estimates for pipeline costs are summarized in Table 7.10.

The pipeline costs used in the model take the value of the higher diameter it is between two of the options (i.e. a 10-in. pipeline is assumed to cost \$1 000 000 per mile).

For the cost of local pipelines the total length must be considered, so the average length of each local pipeline must be multiplied by the number of local pipelines to determine the total capital cost. The total capital cost of the pipeline and the compressors are then annualized using the pipeline capital recovery factor, calculated in the model.

Table 7.10. Pipeline cost estimates

Diameter (inches)	Pipeline cost (\$/mile)
3	400 000
9	900 000
12	1 000 000
14	1 400 000

Source: Mintz et al. (2002).

Finally, the total cost per kilogram for hydrogen transport via pipeline is found in the same way that other options are calculated, by dividing the total annual cost by annual production.

### Hydrogen distribution

Hydrogen distribution costs include storage, transportation, and fuel station costs. H<sub>2</sub>Sim includes nine possible scenarios. Table 7.11 summarizes estimated distribution costs for the default H<sub>2</sub>Sim scenario of low production (100 000 kg/day) and short delivery distance (100 miles). Estimated costs for high production (1 000 000 kg/day) and long distance (500 miles) are summarized in Table 7.12. Each option assumes hydrogen is stored for one day. As indicated in the tables, the hydrogen distribution costs may be significant, suggesting that the future viability of a hydrogen economy may depend on achieving reductions in these storage and transportation costs.

NAE (2004) recently reached a similar conclusion. Specifically, NAE found that pipeline shipment and dispensing would be the lowest cost option, costing 0.96 \$/kg, “which is essentially equal to the cost of production.” The authors conclude that “even with possible future improvements in shipping and distribution, this cost is much more than today’s gasoline dispensing and distribution costs, at 0.19 \$/gal.” And NAS notes that the analysis “demonstrates the realities of shipping H<sub>2</sub> gas versus the much more efficient shipment of a liquid.”

For the default case (Table 7.11), estimated costs range from a low of 1.13 \$/kg to 4.29 \$/kg. At the low end is underground storage of compressed gas with large pipelines connected to a series of smaller pipelines that deliver the hydrogen to a fueling station with compressed gaseous storage (Option 1). Another lower-cost option (Option 4), at 1.44 \$/kg, is the case of liquid storage, with truck delivery. Transporting the liquid hydrogen by truck is fairly inexpensive (0.07 \$/kg). The largest cost, included here in the storage costs (0.87 \$/kg), are the liquefaction costs. Distribution of gaseous hydrogen by truck or rail would be considerably more expensive (2.02–4.29 \$/kg) due to the low volumetric density of the hydrogen. Note that while the estimated fueling station costs are significant (0.41 \$/kg for gaseous storage and dispensing; 0.50 \$/kg for liquid storage and dispensing), other sources including Ogden (1999) suggest that such costs could add as much as 0.52–0.78 \$/kg to the costs presented here.

For greater quantities of hydrogen (Table 7.12), while it may make sense to use gaseous truck transport for local delivery (Option 5), gaseous truck transport becomes prohibitively expensive for long distances. For the case of pipelines, while distance has increased five times

Table 7.11. Hydrogen distribution costs for nine H<sub>2</sub>Sim scenarios: low production (100 000 kg/day), short distance (100 miles)

Scenarios <sup>1</sup>	UND pipe-large pipe-local FS	GH pipe-large pipe-local FS	GH truck-GH none FS	LH truck-LH none FS	GH pipe-large truck-GH FS	MH truck-MH none MH	GH rail-GH truck-GH FS	LH ship-LH truck-LH FS	LH rail-LH truck-LH FS
Storage 1	0.16	0.25	0.25	0.87	0.25	0.84	0.25	0.87	0.87
Delivery 1	0.44	0.44	1.36	0.07	0.50	0.87	3.05	1.70	0.20
Local delivery	0.13	0.13	0.00	0.00	0.61	0.00	0.61	0.03	0.03
End storage	0.41	0.41	0.41	0.50	0.41	0.84	0.41	0.50	0.50
Total	1.13	1.22	2.02	1.44	1.77	2.56	4.29	3.09	1.59

<sup>1</sup> Scenarios written Storage 1/Delivery 1/Local delivery/End storage.

UND, Underground; GH, Gaseous hydrogen; LH, Liquefied Hydrogen; MH, Metal Hydride; FS, Fueling Station.

Table 7.12. Hydrogen distribution costs for nine H<sub>2</sub>Sim scenarios: high production (1 000 000 kg/day), long distance (500 miles)

Scenarios <sup>1</sup>	UND Pipe-large Pipe-local FS	GH Pipe-large Pipe-local FS	GH Truck-GH none FS	LH Truck-LH none FS	GH Pipe-large Truck-GH FS	MH truck-MH none MH	GH rail-GH truck-GH FS	LH ship-LH truck-LH FS	LH rail-LH truck-LH FS
Storage 1	0.15	0.20	0.20	0.70	0.20	0.84	0.20	0.70	0.70
Delivery 1	1.38	1.38	5.22	0.27	1.44	3.27	3.05	1.93	0.20
Local delivery	1.04	1.04	0.00	0.00	0.61	0.00	0.61	0.03	0.03
End storage	0.41	0.41	0.41	0.50	0.41	0.84	0.41	0.50	0.50
Total	2.98	3.03	5.83	1.46	2.66	4.95	4.26	3.15	1.42

<sup>1</sup> Scenarios written Storage 1/Delivery 1/Local delivery/End storage.

UND, Underground; GH, Gaseous Hydrogen; LH, Liquefied Hydrogen; MH, Metal Hydride; FS, Fueling Station.

and the flow rate eight times, pipeline delivery costs triple as pipeline capacity is used more adequately. These results also suggest the cost of delivering liquid hydrogen actually drops, largely due to economies of scale associated with the liquefaction process. A close look at the differences between the two scenarios suggests picking the low-cost option for any particular region will require some type of optimization that take the key factors into account. For example, for less densely populated areas, the low-cost option may not include pipelines. For areas of greater demand, some combination of pipeline and/or truck delivery may minimize costs. The results also show ways in which H<sub>2</sub>Sim requires future work. For example, the model suggests rail transport costs are identical in multiple model scenarios, since distance is not explicitly taken into account.

### Sensitivity Analysis

This section further analyzes the sensitivity of the distribution results to several key variables including storage time, hydrogen production rates, and transport distances.

Storage costs are highly dependent on the type of storage, storage time, and hydrogen production rates (Figures 7.3 and 7.4).

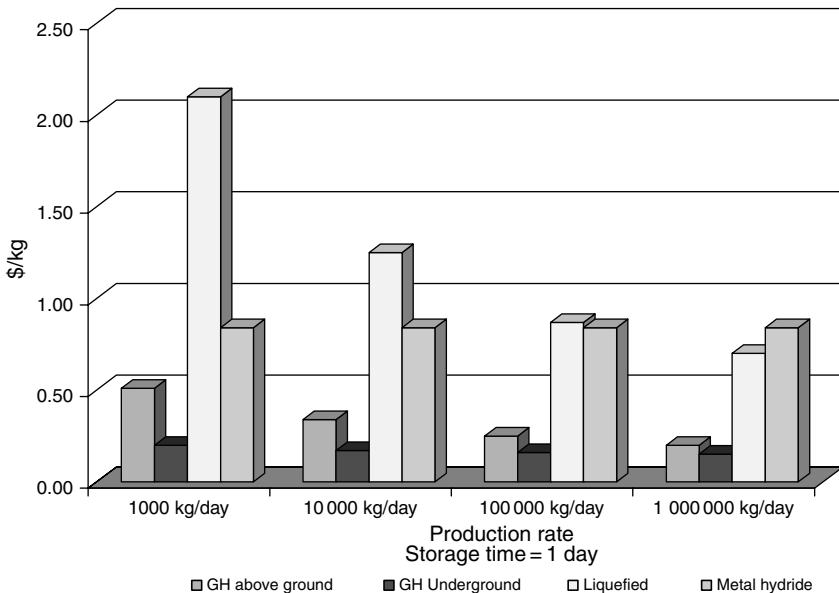


Figure 7.3. Storage costs as a function of hydrogen production rate.

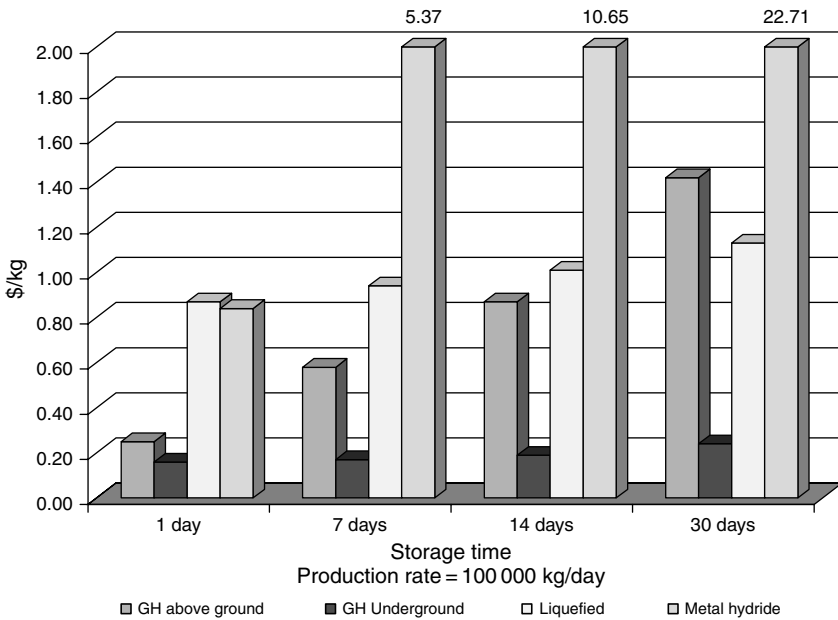


Figure 7.4. Storage costs as a function of storage time.  
 (Note: Metal hydride storage costs exceed the scale for storage times of 7 days or more.)

Figure 7.3 shows how production rates affect projected storage costs. Storage costs are generally lowest for underground storage options, although this option requires the existence of underground caverns suitable for storage. With the exception of metal hydride storage, costs decrease as the production rate increases, due to economies of scale. Aboveground gaseous storage is the second-cheapest option. However, it is more expensive to transport hydrogen in a gaseous form due to its low density.

As the storage time and the necessary capacity increases, the costs of some storage options are greatly affected while others are less sensitive (Figure 7.4). While the low cost of underground gaseous storage remains essentially unchanged, costs for aboveground storage increase, as increased storage time requires a larger number of tanks. Because liquefied hydrogen storage is less sensitive to storage time than aboveground gaseous storage, it becomes the least costly and most consistently available option for long storage times, while underground gaseous storage remains the least expensive option when geographically possible. In contrast, metal hydride storage is extremely sensitive to storage time, becoming progressively more expensive than other options as storage time increases.

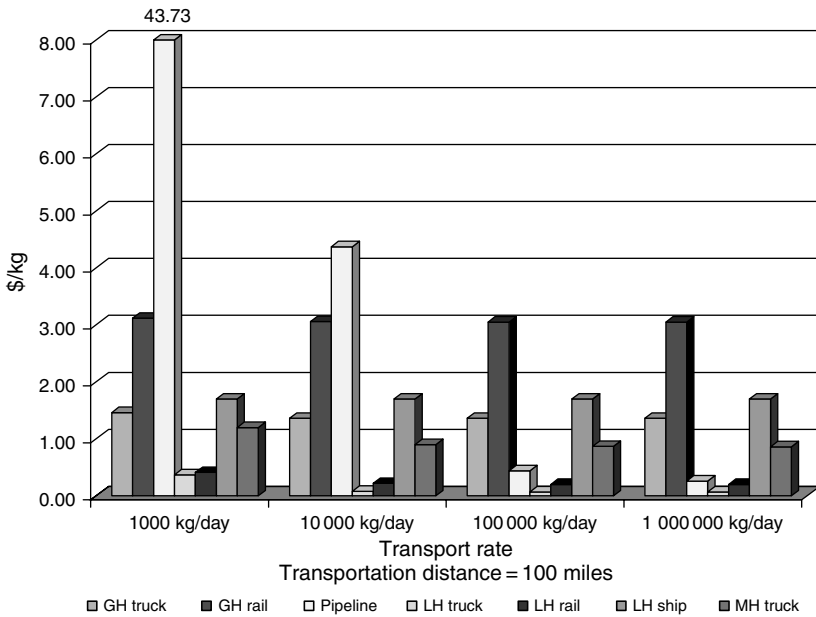


Figure 7.5. Transportation costs for 100 miles as a function of hydrogen transport rate. (Note: Pipeline transportation costs exceed the scale for a transport rate of 1000 kg/day.)

Hydrogen transportation costs are determined by two primary factors: transport rate and transportation distance. Figure 7.5 illustrates the relationship between transportation costs and transport rate for hydrogen delivered 100 miles ( $H_2Sim$ 's default setting). Liquefied hydrogen and pipeline transport are the two options most affected by transportation rates. With the exception of pipeline transport, costs level off at rates greater than 10 000 kg/day. The cost of the other options level off after reaching a transport rate of 10 000 kg/day. Pipeline transport is the most sensitive due to the pipelines' high capital cost, which is spread over a larger delivered quantity as the production rate increases. With all other transport options, the quantity of trucks and railcars is easily varied to meet the demand.

As transport distance increases, so do transportation costs. Figure 7.6 illustrates the sensitivity of transportation options to transport rates for a higher transportation distance of 1000 miles. For example, gaseous hydrogen transport by truck would cost about 10\$/kg for a transportation distance of 1000 miles compared to a cost of just over 1\$/kg for a transportation distance of 100 miles (Figure 7.5) regardless of the transportation rate. As with shorter transportation distances, pipeline

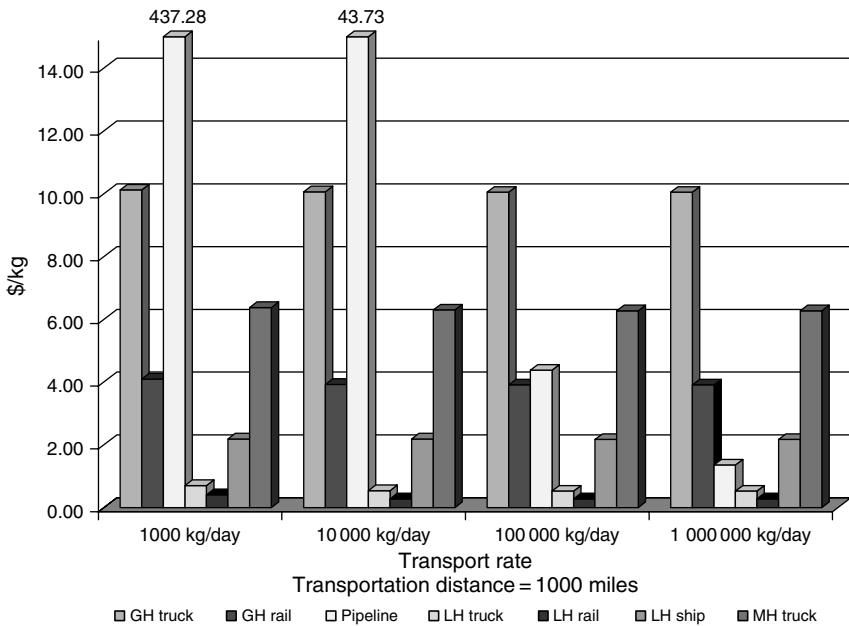


Figure 7.6. Transportation costs for 1000 miles as a function of hydrogen transport rate. (Note: Pipeline transportation costs exceed the scale for transport rates of 10 000 kg/day or less.)

transportation is very sensitive to the flow rate, costing far more than any other option in the two lower transportation rate scenarios. However, as the flow rate increases, costs decrease, reaching 1.52 \$/kg for a flow rate of 1 000 000 kg/day. Minimizing the pipeline costs for this high transport, high flow rate requires utilizing a larger pipeline (14 in.) than is assumed for the other cases (12 in.). For the case of 12-in. pipelines, H<sub>2</sub>Sim suggests pipeline transport costs are minimized in the 1000 mile case at flow rates of around 500 000 kg/day (1.46 \$/kg). Liquefied transport costs are also fairly low, but when coupled with liquefaction and storage costs, would not be less expensive than pipeline transport.

Transportation costs increase across the board as distance increases. Figure 7.7 examines this relationship further, showing the sensitivity of each transportation option to the transportation distance at a constant transport rate. At the shortest distance of 10 miles, which could be used for local hydrogen distribution, pipelines and liquefied hydrogen trucks provide the least expensive options. However, the price of transporting liquefied hydrogen via rail, or truck transportation of gaseous hydrogen or metal hydrides, also is low, adding less than 0.61 \$/kg. This cost does

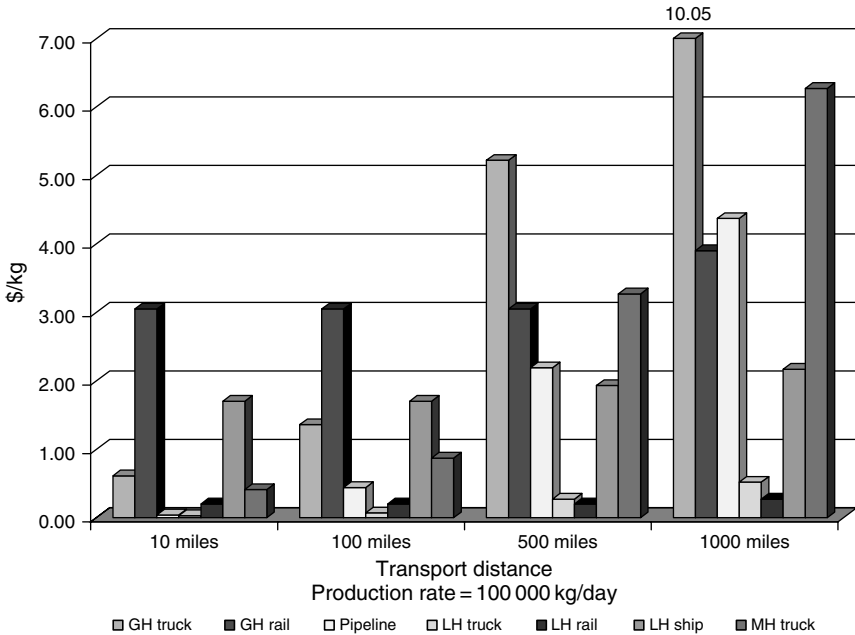


Figure 7.7. Transportation costs as a function of distance.  
(Note: GH Truck costs exceed the scale for a distance of 1000 miles.)

not include the liquefaction costs, which are significant. However, for this relatively low flow rate, as the transportation distance increases, the cost of some options increase greatly, while others remain fairly constant. While pipeline was very inexpensive at a low transportation distance, it is highly sensitive. Therefore costs increase quickly with respect to longer transport distances. The same is true for other gaseous hydrogen transportation options and metal hydride transport. However, all liquefied hydrogen transportation options, especially rail, are relatively insensitive to distance. Liquefied hydrogen is, therefore, the least expensive option when distances reach 1000 miles at the  $H_2Sim$  default transport rate of 100 000 kg/day.

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# Chapter 8

## End Use

Hydrogen can be used in both vehicles and stationary sources. The current version of H<sub>2</sub>Sim focuses mainly on end use in the transportation sector. Future versions may contain additional analysis of stationary options.

### Vehicles

H<sub>2</sub>Sim compares costs of existing vehicle types (conventional internal combustion engines [ICE], hybrid, and electric) with 2020 forecasted technologies (fuel cell vehicles [FCVs], hybrids running on hydrogen [H<sub>2</sub>Hybrid] vehicles and FCVs with onboard reformation [FCV OB]). Of course, current technologies also may improve dramatically by 2020. The fuel efficiency of ICE vehicles, for example, may increase dramatically if there is a large shift to light-weight materials.

The default assumptions for each vehicle type are summarized in Table 8.1. The assumed cost and performance of the gasoline hybrid and electric vehicles are based on current technology. The hybrid price and estimated mileage is based on the average retail price and efficiencies of the three existing hybrid vehicles on the market – the Honda Insight, the Honda Civic, and the Toyota Prius. The cost and performance of the electric vehicle (EV) is based on the recently retired GM EV1.

Costs of FCVs are 2020 mid-size vehicle estimates from Weiss et al. (2000, 2003) at MIT. However, while Weiss et al. suggest fuel efficiencies for FCVs above 90 miles per gallon gas equivalent (mpgge) in their 2000 study and even higher in an updated 2003 study, we have chosen a more conservative estimate for fuel efficiency of 69.5 mpgge. This is 2.5 times the assumed efficiency of the ICE vehicle. The implications of this assumption are explored in the sensitivity results section of this paper. H<sub>2</sub>Sim assumes H<sub>2</sub>Hybrid vehicles will be comparably priced to ICE vehicles (\$18 000) once mass-produced, as the technology is

Table 8.1. Default vehicle assumptions

Vehicle	Technology year	Vehicle price (\$)	Maintenance	Insurance (\$/yr <sup>2</sup> )	License and registration	Fuel efficiency (mpg)
ICE		18000	696	972	384	27.8
Hybrid	2003	19736	696	972	384	55.0
EV		33995	696	972	384	46.3
H <sub>2</sub>						
Hybrid		18000	696	972	384	45.0
FCV	2020	22100	696	1104	480	69.5
FCV OB		25910 <sup>1</sup>	696	1104	480	61.0

<sup>1</sup> Includes a vehicle cost of \$22100 and a reformer cost of \$3810.

<sup>2</sup> Based on the vehicle being driven 12000 miles per year.

not significantly more advanced. Maintenance, insurance, and licensing costs all are based on estimates from Weiss et al. (2000).

Onboard reformation of gasoline solves many problems associated with the lack of a hydrogen infrastructure. Drivers would continue to fuel their vehicles the same way they do now. The fuel then would be reformed onboard the vehicle, providing hydrogen for the fuel cell. Proponents of this option suggest onboard reformation might be a good transition strategy. Once sufficient cars are equipped with fuel cells, the hydrogen infrastructure could develop. This option does not resolve concerns about CO<sub>2</sub> emissions.

While it is technically possible to use fuels other than gasoline, such as methanol, for this process, H<sub>2</sub>Sim initially assumes onboard reformers would utilize gasoline.

A.D. Little (2001) estimates that a reformer sized to fuel a 50 kW fuel cell would cost approximately \$3810, or 76 \$/kW, assuming an operating efficiency of 48.1%. This capital cost is added to the assumed cost of the FCV. The extra weight of the reformer means that this vehicle will be less fuel efficient than the FCV. H<sub>2</sub>Sim assumes a default fuel efficiency of 61 mpgge. The rated input for this reformer is 136.9 kilojoules per second (kJ/s) gasoline. Based on an efficiency of 48.1%, the hydrogen output is 103.9 kJ/s.<sup>1</sup> The cost of hydrogen is then given by:

$$P_H = P_G \frac{\text{Gas}_{\text{in}}}{H_{\text{Out}} \text{LHV}_H} \quad (1)$$

where:  $P_H$  is the hydrogen production cost (\$/GJ);  $P_G$  is wholesale gasoline cost (\$/gallon);  $\text{Gas}_{\text{in}}$  is gasoline flow rate (gallon/h);  $H_{\text{out}}$

<sup>1</sup> 50 kW = 50 kJ/s / 0.481 = 103.9 kJ-H/sec

Table 8.2. Fuel carbon coefficients

Fuel	Carbon coefficient (MtCO <sub>2</sub> /Quad)
Coal	94.46
Natural gas	53.06
Gasoline	70.99
Crude oil	74.22

is hydrogen flow rate (kg/hr);  $LHV_H$  is the hydrogen lower heating value (GJ/kg).

### Carbon Emissions

H<sub>2</sub>Sim calculates the carbon emissions associated with each fuel choice. Table 8.2 summarizes the carbon coefficients, in million metric tons carbon per quad (MtCO<sub>2</sub>/quad), used in H<sub>2</sub>Sim.<sup>2</sup> These coefficients do not include carbon emissions associated with car manufacture or fuel delivery, and hence understate total carbon emissions. Actual emissions are determined by the efficiency of the conversion process as well as the use. For example, the total emissions from a vehicle using hydrogen produced by electrolysis are determined by the efficiency of the electricity production, electrolysis process, and FCV.

### End Use Costs

H<sub>2</sub>Sim compares the end-use cost of using hydrogen in either FCV or hybridized, direct hydrogen combustion vehicles in 2020 with today's internal combustion engine vehicles, hybrid, and electric vehicles. It also considers a 2020 FCV with onboard production of hydrogen. The default costs associated with each of the vehicles included in H<sub>2</sub>Sim were summarized in Table 8.1. This chapter focuses on the fuel and the total end-use costs associated with each vehicle based on fuel and vehicle cost sensitivity analysis.

Table 8.3 summarizes fuel costs, in cents per mile driven, for the various vehicle types. These results use the default values in H<sub>2</sub>Sim, including the assumption of low hydrogen production and short distance. These costs do not include any carbon capture and sequestration. Depending on the distribution option selected, the estimated fuel costs

<sup>2</sup> Carbon coefficients from DOE (1999), Table B1.

Table 8.3. Fuel costs (cents/mile) for ICE, hybrid, EV, H<sub>2</sub>Hybrid, FCV, and FCV OB, assuming the default vehicle efficiencies summarized in Table 8.1

Vehicle Prod method <sup>2</sup>	Storage and delivery method <sup>1</sup>									
	UND pipe-large pipe-local FS	GH pipe-large pipe-local FS	GH truck-GH none FS	LH truck-LH none FS	GH pipe-large truck-GH FS	MH truck-MH none MH	GH rail-GH truck-GH FS	LH ship-LH truck-LH FS	LH rail-LH turck-LH FS	none
ICE	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56
Hybrid	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
EV	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42
H <sub>2</sub> Hybrid										
SMR	6.26	6.49	8.44	7.03	7.83	9.75	14.05	11.06	7.40	3.50
Coal gas	4.73	4.97	6.91	5.50	6.30	8.23	12.52	9.53	5.87	1.98
Electrolysis <sup>3</sup>	9.58	9.82	11.76	10.35	11.15	13.08	17.37	14.38	10.72	6.83
Th CSP <sup>4</sup>	7.93	8.16	10.10	8.69	9.50	11.42	15.71	12.73	9.07	5.17
Th nuclear	6.42	6.66	8.60	7.19	7.99	9.92	14.21	11.22	7.56	3.67
NPO	6.97	7.21	9.15	7.74	8.54	10.47	14.76	11.77	8.11	4.22
FCV										
SMR	4.05	4.20	5.46	4.55	5.07	6.32	9.09	7.16	4.79	2.27
Coal gas	3.06	3.22	4.47	3.56	4.08	5.33	8.10	6.17	3.80	1.28
Electrolysis <sup>3</sup>	6.21	6.36	7.61	6.70	7.22	8.47	11.25	9.31	6.94	4.42
Th CSP	5.13	5.28	6.54	5.63	6.15	7.39	10.17	8.24	5.87	3.35
Th nuclear	4.16	4.31	5.57	4.65	5.17	6.42	9.20	7.26	4.90	2.37
NPO	4.51	4.67	5.92	5.01	5.53	6.78	9.56	7.62	5.25	2.73
FCV OB	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32

<sup>1</sup> Scenarios written Storage 1/Delivery 1/Local delivery/End storage.

UND, Underground; GH, Gaseous hydrogen; LH, Liquefied hydrogen; MH, Metal hydride; FS, Fueling station.

<sup>2</sup> ICE, Hybrid, EV are vehicle technology in 2003. H<sub>2</sub> Hybrid, FCV, FCV OB are vehicle technology in 2020.

ICE, Internal combustion engine; EV, Electric vehicle; FCV, Fuel cell vehicle; FCV OB, Fuel cell vehicle with onboard reformer.

<sup>3</sup> Assumes the use of electricity from gas combined cycle.

<sup>4</sup> Th, Thermochemical.

will change as hydrogen production rates and distances increase. Obviously, the cost of hydrogen does not affect the operating costs of the ICE, hybrid, FCV OB, or EV. The EV, which is fueled by electricity, has the lowest fuel cost per mile (1.42 cents/mile), followed by hybrid vehicles (1.80 cents/mile) because of their high fuel efficiencies. The conventional ICE vehicle has the highest fuel cost of the non-hydrogen vehicles (3.56 cents/mile) because of its lower fuel efficiency.

Of the various hydrogen options, H<sub>2</sub>Sim suggests that fuel costs for a FCV may be as low as 3.06 cents/mile for hydrogen from coal gasification delivered by large regional pipelines and smaller local pipelines. This compares favorably to the fuel costs for the conventional ICE vehicle (3.56 cents/mile), but is more expensive than the hybrid vehicles (1.80 cents/mile). At higher flow rates (800 000 kg/day delivered 100 miles), the hydrogen fuel costs fall as low as 2.68 cents/mile. For the H<sub>2</sub>Hybrid vehicle, the estimated fuel cost for the default value is 6.26 cents/mile, somewhat higher than the FCV option (4.05 cents/mile) due to the lower overall vehicle efficiency. The FCV with onboard processing has estimated costs of 2.32 cents/mile. In terms of yearly fuel costs, it would cost \$427 for the conventional ICE vehicle compared to \$367 for the FCV (least cost option), an annual savings of just \$60, suggesting a simple payback in excess of 68 years for the FCV.

Focusing on fuel costs per mile (or even aggregate) is rather misleading, however, as fuel costs are a small component of total driving costs. The total cost per mile is determined by the cost of the vehicle, license and registration, insurance, maintenance, and fuel. Table 8.4 summarizes the total costs per mile for each vehicle in H<sub>2</sub>Sim. As previously mentioned, H<sub>2</sub>Sim compares predicted 2020 costs for the hydrogen vehicles

Table 8.4. Total end-use costs

Vehicle	Total cost (\$/mile)	Vehicle cost
ICE	0.55	18 000
Hybrid	0.56	19 736
EV <sup>1</sup>	0.82-0.88	33 995
H <sub>2</sub> Hybrid <sup>2</sup>	0.56-0.61	18 000
FCV <sup>2</sup>	0.64-0.67	22 100
FCV OB	0.70	25 910 <sup>3</sup>

<sup>1</sup> Ranges from least expensive to most expensive electricity production options; does not include T&D costs.

<sup>2</sup> Ranges from least expensive to most expensive hydrogen production options; assumes distribution Option 1.

<sup>3</sup> Includes a vehicle cost of \$22 100 and a reformer cost of \$3810.

with 2003 costs for the ICE, hybrid, and electric vehicle technologies. The results here must be interpreted carefully as existing vehicles also will experience technological improvements that may increase their overall efficiency.

In considering the least expensive hydrogen production option (coal gasification), the H<sub>2</sub>Hybrid vehicle is the cheapest hydrogen vehicle to operate overall and is competitive with today's ICE vehicle (with 2020 wholesale gasoline prices). However, if other hydrogen production options are used, today's ICE vehicle and today's hybrid are the lowest cost. Today's EV and the 2020 FCV OB have the highest end-use costs because of the EV battery costs and the FCV OB's onboard reformer cost (which adds almost \$4000 to the vehicle cost). Despite the lower overall fuel costs, H<sub>2</sub>Sim estimates FCVs will cost 9–11 cents more per mile to operate than conventional ICE vehicles. This is an important result; despite higher fuel efficiency and lower fuel costs, FCVs will have a difficult time competing with conventional ICE or hybrid technologies. The actual cost of delivered hydrogen is not that important in terms of the overall economic competitiveness of the FCV.

### Sensitivity Analysis

Figure 8.1 illustrates break-even costs for the various vehicle types as a function of hydrogen price. Based on the default assumptions of

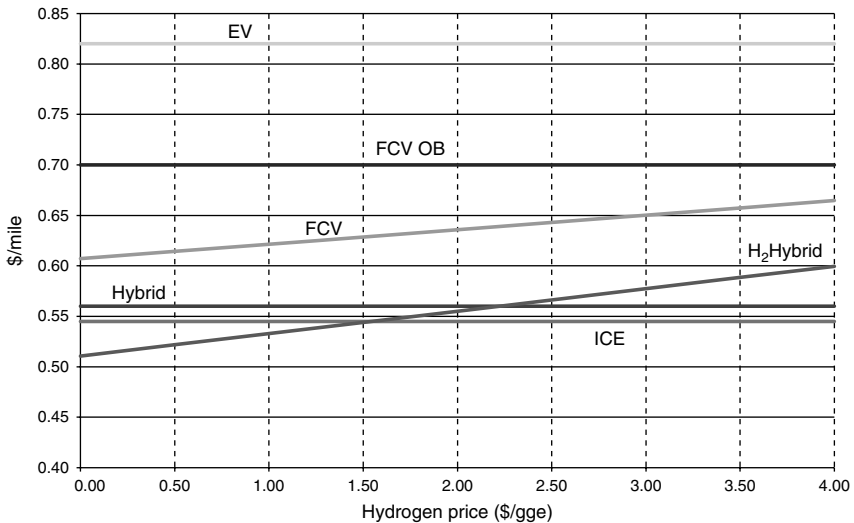


Figure 8.1. Hydrogen price end-use sensitivity.

H<sub>2</sub>Sim, 2020 H<sub>2</sub>Hybrid vehicles become competitive with ICE vehicles, using today's technologies, when the delivered price of hydrogen is 1.95 \$ gallon gas equivalent (gge).<sup>3</sup> Based on the default assumptions about FCVs, they cannot compete with ICE or hybrid technologies, even if the hydrogen is free. The implication is that FCVs will require further reductions in vehicle costs or significant increases in gasoline prices, through market forces or government policy changes, in order to compete with other technologies. Alternatively, the FCV will have to offer something new that consumers are willing to pay more for, such as performance, emissions profile, or some other factor.

Vehicle price and gasoline costs are factors in the overall competitiveness of the FCV. As Table 8.4 showed, vehicle price rather than fuel price dominates the total cost per mile. Figure 8.2 illustrates the vehicle costs required for advanced technologies to be competitive with existing conventional ICE vehicles. This analysis assumes that the hydrogen is produced from coal gasification, without carbon capture and sequestration, and utilizes distribution option 1 from Table 7.6 (underground gaseous storage, large central pipeline, small, local pipeline connecting to fueling stations). Based on the default assumptions for the ICE

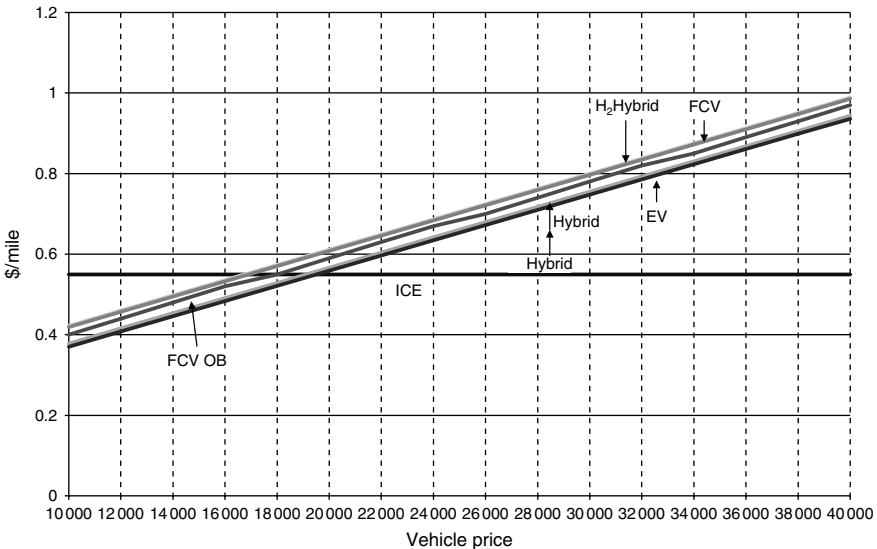


Figure 8.2. Vehicle price sensitivity.

<sup>3</sup> Compared on a Btu basis.

technology, this analysis shows that hybrids must be priced at \$19 300 and electric vehicles at \$19 500, to become competitive with the default ICE vehicle. FCVs and H<sub>2</sub>Hybrid vehicles, however, are only competitive at prices of \$17 000 or less, a decrease of \$5100 and \$1000 from the default values, respectively. The price of the FCV with OB reformation would have to fall to around \$18 000, including the cost of the onboard reformation system.

The relative competitiveness of hydrogen vehicles to gasoline vehicles is sensitive to the price of gasoline. As gasoline prices increase, so do gasoline vehicle end-use costs, especially for today's less efficient ICE vehicles (Figure 8.3). The greater efficiencies of today's hybrids and FCV OBs makes them less susceptible to gasoline price variations. H<sub>2</sub>Hybrid vehicles fueled with hydrogen from a centralized coal gasification facility, with liquefied storage and truck transport, are the least expensive hydrogen option. H<sub>2</sub>Hybrid vehicles become cost competitive with hybrids and ICE vehicles when wholesale gasoline prices reach approximately 1.60 \$/gallon and 1.75 \$/gallon, respectively. Fuel cell vehicles, using the same delivered hydrogen option, however, do not become cost competitive with ICE vehicles until wholesale gasoline prices exceed 3.50 \$/gallon. Gasoline prices would have to exceed 5.20 \$/gallon before FCVs were competitive with existing hybrids, a highly

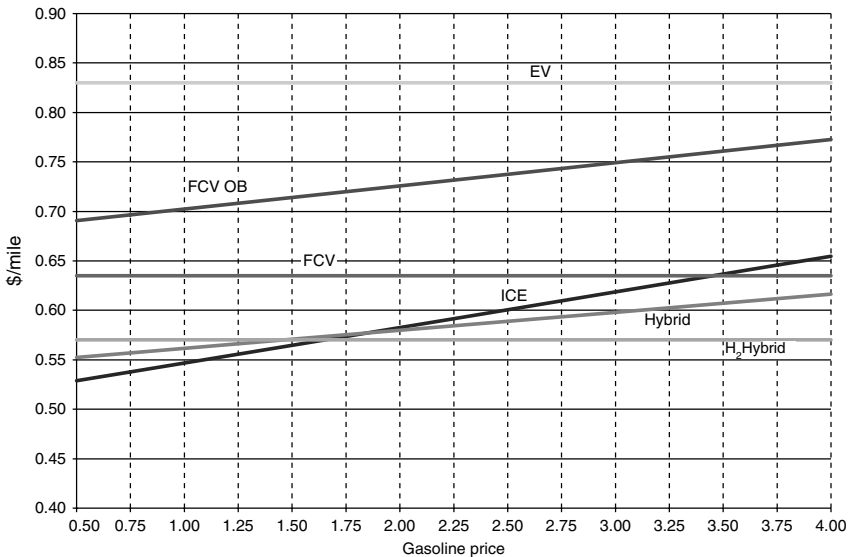


Figure 8.3. Wholesale gasoline price end-use sensitivity.

Table 8.5. Total carbon emissions by vehicle type

Vehicle/Fuel option	Carbon emissions (metric tons C/yr)
ICE	1.04
Hybrid	0.52
EV <sup>1</sup>	0.00–0.71
H <sub>2</sub> Hybrid	
Steam methane reformation <sup>2</sup>	0.65/0.11
Coal gasification <sup>2</sup>	1.16/0.16
Electrolysis <sup>1</sup>	0.00–2.08
Thermochemical CSP	0.00
Thermochemical nuclear	0.00
NPO	1.74
FCV	
Steam methane reformation <sup>2</sup>	0.42/0.07
Coal gasification <sup>2</sup>	0.75/0.10
Electrolysis <sup>1</sup>	0.00–1.35
Thermochemical CSP	0.00
Thermochemical nuclear	0.00
NPO	1.13
FCV OB	0.82

<sup>1</sup> Depends on generating source. Lowest levels are from Nuclear, Solar PV, Solar thermal, and Wind. Highest emissions are from coal.

<sup>2</sup> Without sequestration/With sequestration

unlikely scenario for the United States in the absence of higher taxes. Furthermore, FCV OB and today's EV vehicles are not competitive with hydrogen, ICE, or hybrid vehicles at any gasoline price.

Estimated annual carbon emissions by vehicle type and fuel source are summarized in Table 8.5. Existing hybrid vehicles emit half as much carbon as 2003 ICE vehicles, explainable by the difference in assumed fuel efficiencies. For the EV, annual carbon emissions depend on the source of electricity. Annual estimates range from zero for non-carbon based electricity sources to 0.71 tons per year if coal is used to produce electricity.

Estimated carbon emissions for the various future technologies depend on the source of hydrogen and whether the carbon is captured and sequestered. In the absence of carbon sequestration, carbon emissions may be greater than from existing hybrid vehicles (0.75 tC per year for hydrogen from coal gasification). However, with carbon sequestration, the same FCV would release 90% less than existing vehicles (0.10 tC per year). If fueled with hydrogen from electrolysis using carbon-based electricity, annual emissions would actually be greater than existing

vehicles (1.35 tC/year), clearly illustrating that wide-scale adoption of FCVs does not guarantee lower carbon emissions.

## **References**

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# Chapter 9

## User's Guide

The Hydrogen Futures Simulation Model allows the user to explore options for producing, distributing, and using hydrogen. The model provides answers to questions about economic viability and the environmental and energy security consequences associated with various hydrogen pathways by allowing the user to quickly change key assumptions. This guide is intended for the first-time user. It demonstrates use of the model, including the running of reference cases and altering of key assumptions. Several examples take the user step-by-step through illustrative scenarios.

### System Requirements

H<sub>2</sub>Sim will run on all Pentium class computers. It is best viewed with display resolutions set to 1024 × 768, large fonts. It also will run satisfactorily with the display settings higher than 1024 × 768, large fonts, or set to 800 × 600, small fonts. The user can change the display settings by opening the display icon in the control panel, accessible from the START menu in Windows. For systems running Windows XP, the font selection is on the settings tab under “advanced.” The model is written in Powersim Studio 2005, a dynamic simulation modeling language.<sup>1</sup>

### Starting the Model and Running a Base Case

The CD includes the necessary Powersim Studio 2005 software to run H<sub>2</sub>Sim. To install the Powersim software, follow these steps:

1. PLACE the CD in the appropriate computer drive on the target computer, locate and open the file “PS2005” on the CD.
2. FOLLOW the installation instructions for Powersim Studio 2005.

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<sup>1</sup>More information about Powersim is available at their website: [www.powersim.com](http://www.powersim.com)

3. ENTER the long serial number listed on the CD cover when prompted on the Customer Information page.
4. ACCEPT the license agreement to use the software.
5. CHOOSE the Complete installation option.
6. CLICK install.

While H<sub>2</sub>Sim can run directly from the CD, performance will improve if the files are copied to your computer. Double click on the file “H<sub>2</sub>Sim.sip” to open the model. To open the model while the Powersim Studio software is running, choose files of type “.sip” in the “Open” window. Locate the file “H<sub>2</sub>Sim.sip” on the CD and click “Open” to run the model.

The model opens on the license agreement page. Accepting the terms of use takes the user to the title page (Figure 9.1). The user advances from this point by clicking on the large arrow labeled **Model** in the lower right-hand corner of the screen. The next screen is a pictorial representation of the hydrogen pathway, followed by the third screen, labeled **Sectional Overview**. The **Sectional Overview** screen explains the four main components of H<sub>2</sub>Sim (Production, Carbon Pathway, Storage and Delivery, and End Use) (Figure 9.2). Clicking on any of the four areas takes the user directly to that section of H<sub>2</sub>Sim. From that point, the user is ready to run the model.

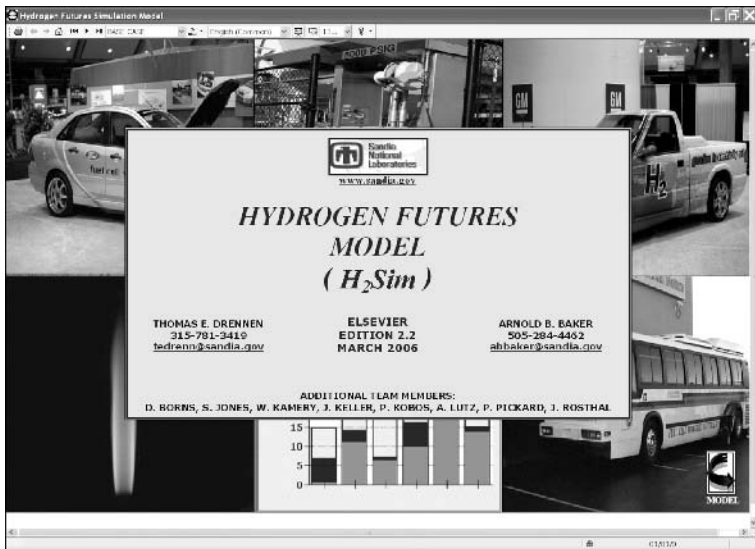



Figure 9.1. H<sub>2</sub>Sim’s title page.





Figure 9.2. Sectional overview screen.

In the bottom right-hand corner of the **Sectional Overview** screen, there is a link to H<sub>2</sub>Sim's legend, which explains the user controls associated with H<sub>2</sub>Sim. Key model controls are summarized below.

### Model Operation

**PLAY**  Click to start model simulation or click during simulation to stop.


**REWIND**  Click to reset simulation.


**PLAY/PAUSE**  Click to advance the model one step.

### Model Navigation

**MAIN TOOLBAR** – Click on desired model section (**Production, Carbon Pathway, Storage and Delivery, Use**) to navigate there.




**HYPERLINK** – Any underlined word acts as a hyperlink. Click on any hyperlink to navigate to the specified location.

**BACK**  **Back** Click to return to previously visited screen.

LEGEND  Click on the compass icon at any time to go to the legend page for a more detailed description of model control and navigation options.

Select **Production** to start at the beginning of the hydrogen pathway.

## Production

H<sub>2</sub>Sim generates output based on the dynamic variable, capital cost. To start the model at the beginning of the simulation, press **Rewind** (). Rewinding the model at any time will restore all assumptions to their default values. To run the model without pause, press **Play** (). To run the model one step forward, use the **Run/Pause** button (). Each model step in H<sub>2</sub>Sim corresponds to a 10 \$/kW-H<sub>2</sub> increase in assumed capital costs<sup>2</sup> for the various technology options, from a capital cost of 0 \$/kW-H<sub>2</sub> to 2000 \$/kW-H<sub>2</sub>. The model pauses automatically at 670 \$/kW-H<sub>2</sub> – the highest assumed 2020 capital cost for any of the production technologies (thermochemical nuclear). If the user sets capital costs at higher values, the model then would pause automatically at that user-set capital cost. The capital cost for which the model is currently calculating costs always is depicted on the right-hand side of the title bar, towards the top of the page.

The results change as the model runs. To change the displayed units, click on the hyperlinks on the left-hand side of each graph (**\$/Kg** or **\$/GJ**). To view the results in tabular form, click on the **Table** hyperlink.

Within the **Production** section, there are hyperlinks to detailed analyses of the six hydrogen production options included in H<sub>2</sub>Sim. Figure 9.3 illustrates the natural gas reformation option. This screen also illustrates the default model results. Key assumptions on each production page include capital, operation and maintenance, and fuel costs, thermal efficiency of the process, interest and discount rates, construction time, plant life, and capacity factor. While some of the assumptions are specific to that production option, changes to assumed interest or discount rates apply to the entire model. Any shaded boxes, such as capital recovery factor, cannot be changed by the user, but will change as other variables (in this case discount rate) do. With the exception of

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<sup>2</sup> Economists typically discuss capital costs in terms of dollars per unit or output. This per unit capital cost is usually dependent on the facility size. A larger unit may have lower per unit capital costs than a smaller unit, due to economies of scale. Total capital costs for a facility would then be the per unit capital costs times the assumed output. For example, a hydrogen plant costing 500.9 \$/kW - H<sub>2</sub> that produces 100 000 kg/day of hydrogen would cost approximately 69.5 million \$500.9 \$/kW - H<sub>2</sub> \*kW/1000W\* W/J/s \*10<sup>6</sup>J/MJ\*120 MJ/kg-H<sub>2</sub> \*hr/3600s\*day/24hr\*100 000 kg - H<sub>2</sub>/day.

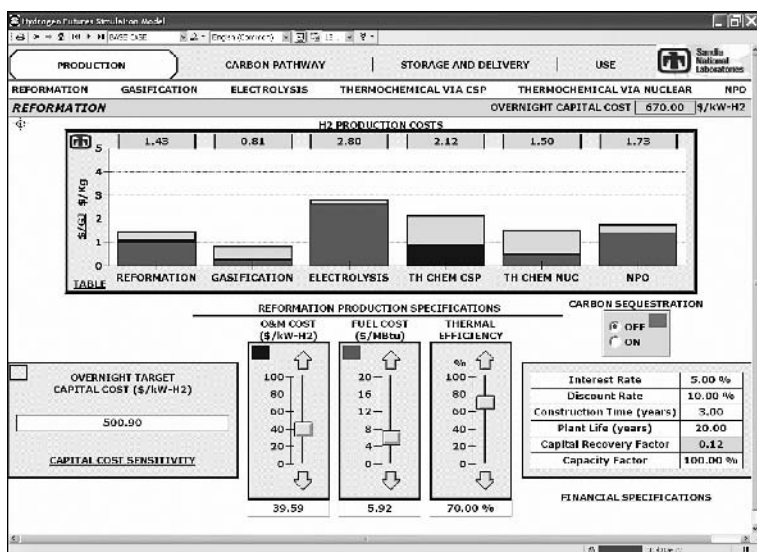


Figure 9.3. Reformation production sensitivity screen.

capital cost, these variables may be changed at any point during the simulation via a slider (Thermal Efficiency, Figure 9.3) or a white number box (Interest Rate, Figure 9.3). Since the model runs on capital cost, this assumption must be changed prior to running the model. (See the shaded box which follows for an example of changing the capital costs.)

### Capital Cost Sensitivity

The **Capital Cost Sensitivity** link, located below the edit boxes for all hydrogen production facilities, takes the user to a summary of projected hydrogen production costs for all capital costs (Figure 9.4). While on this page, one can rerun or change any of the assumptions about a production option; the new scenario will appear as a thin line, while the default scenario will appear as the thick line. Figure 9.4 illustrates this concept by running H<sub>2</sub>Sim to its default stop (670 \$/kW-H<sub>2</sub>). At this point, the price of natural gas was increased to 9 \$/MBtu. The new production costs are shown as the thin green line. This change can be made at beginning of a model run, as shown in Figure 9.3, or during a model run. Clicking on the magnifying glass icon, will take the user to an enlarged view of this graph. Clicking on the **Table** hyperlink in the bottom corner of the graph will take the user to a table summarizing the same information. Arrows on the tabular page indicate the default

### Illustrative Example of Defining a Custom Overnight Target Capital Cost

The default capital cost for natural gas reformation is 500.90 \$/kW-H<sub>2</sub>, based on the estimated costs for a 100 000 kg/day facility built in 2020. Smaller reformation plants likely will have a higher per unit capital cost. One estimate suggests that a smaller, fueling station-sized reformer may cost in the range of 1800 \$/kW-H<sub>2</sub>. This example illustrates how to change the assumed target overnight capital cost from 500 to 1800 \$/kW-H<sub>2</sub>.

- Step 1: Reset the model with the **Rewind** icon (⏮).
- Step 2: Click in the number box labeled **Overnight Target Capital Cost** and change the value to 1800 \$/kW-H<sub>2</sub>.
- Step 3: Press the **Play** icon (▶).

H<sub>2</sub>Sim now stops at 1800 \$/kW-H<sub>2</sub> as the model always stops at the highest specified capital cost of any technology. Based on this increased capital cost, hydrogen production costs, via natural gas reformation, increase from 0.74 \$/kg to 2.17 \$/kg.

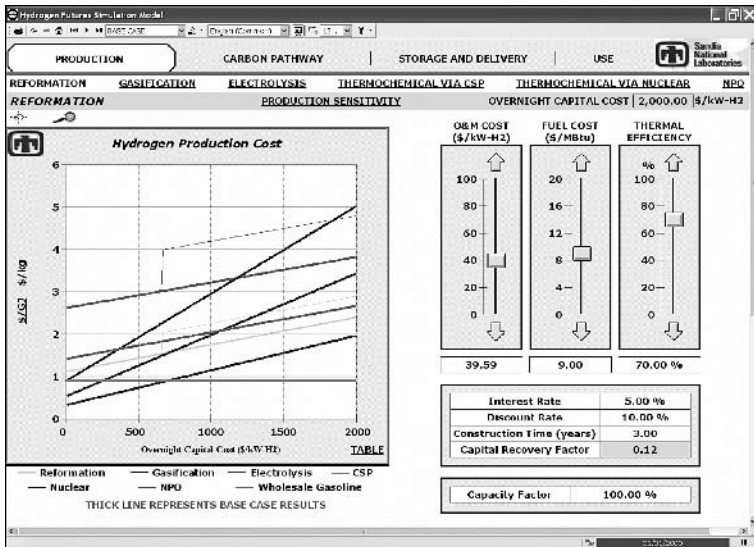


Figure 9.4. Capital cost sensitivity screen.

target capital cost of each production option. From here, one can explore other production options or move on to other parts of the model. With the exception of the electrolysis option, the other production screens are similar to the reformation screen.

The capital cost sensitivity analysis can not be done with Elsevier Edition 2.2 of H<sub>2</sub>Sim. A full version of H<sub>2</sub>Sim is required.

*Electrolysis*

The production sensitivity and capital cost sensitivity for electrolysis allow the user to alter the source of the electricity. The default electricity option assumes electricity is produced using gas combined cycle technology (GasCC). The user may also directly set a price (User Set option). The electricity costs are calculated at the plant gate and do not include transmission and distribution (T&D) costs. T&D costs may be added by the user (Electricity Transmission and Distribution box).

Basic assumptions about the electricity generation in H<sub>2</sub>Sim can be changed by clicking on the Electricity Generation Sensitivity hyperlink. This section of the model allows the user to alter basic assumptions about each electricity production option, including capital costs, fuel prices, and construction time. Figure 9.5 illustrates the options for a GasCC facility. All of the variables on this screen are unique to the electricity

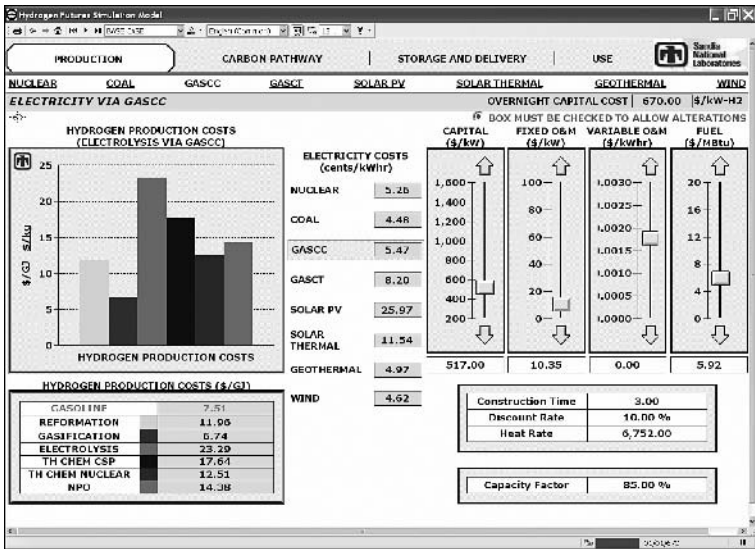


Figure 9.5. Electricity generation sensitivity analysis screen.

generation option with the exception of the discount rate, which carries over throughout the model. The user must select **Allow Alterations** box prior to making changes on this screen. By checking this box, the user is selecting the electricity generation type that the electrolysis production process will use. The electricity generation sensitivity screen also shows a comparison of different production options, allowing the user to examine the competitiveness of hydrogen produced via electrolysis as generating facility assumptions are changed.

The electricity generation sensitivity analysis can not be done with Elsevier Edition 2.2 of H<sub>2</sub>Sim. A full version of H<sub>2</sub>Sim is required.

### **At What Price Would Hydrogen Produced From Electrolysis be Competitive with Other Options?**

This example demonstrates the “what if?” capabilities of H<sub>2</sub>Sim. Using the default assumptions, the cheapest production option for hydrogen is coal gasification (0.81 \$/kg), followed by natural gas reformation (1.43 \$/kg). Hydrogen produced from electrolysis is considerably more expensive (2.80 \$/kg). This example demonstrates how H<sub>2</sub>Sim can be used to find the electricity price at which the electrolysis option is competitive.

- Step 1: Run the model to its default stopping point (670 \$/kW-H<sub>2</sub>).
- Step 2: Click the **Electrolysis** hyperlink at the top of the production summary screen.
- Step 3: Click on the **User Set** option in the plant gate electricity cost **Source** box.
- Step 4: Experiment with electricity prices until the user finds the price at which the electrolysis option is competitive with coal gasification. The user will find that electricity must cost 1.24 cents/kWh.

### **Carbon Pathway**

Both the reformation and gasification options would release significant quantities of carbon during the production process. H<sub>2</sub>Sim allows the user to explore the options for carbon capture, sequestration, and the impact on overall economic competitiveness. Figure 9.6 illustrates the carbon sequestration screen for the coal gasification option. From this screen, the user can specify the additional capital and O&M costs associated with the carbon capture, the percentage of carbon removed (default

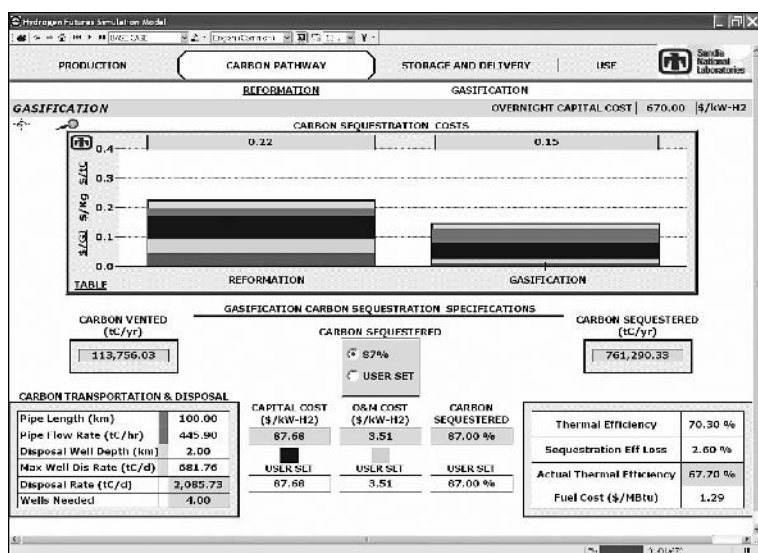


Figure 9.6. Carbon pathway screen for coal gasification option.

is 87%), and the efficiency penalty associated with carbon capture in terms of the hydrogen production process (default is 2.6%). This screen also contains basic assumptions about the distance and rate of carbon transport and the depth of the disposal wells.

For the example illustrated in Figure 9.6, carbon capture and transport adds 0.15 \$/kg (totals may not equal sum of components, due to independent rounding) to the price of hydrogen produced from coal gasification. As with most graphs in  $H_2$ Sim, the results are color coded to show the composition of costs. Clicking on the **Table** hyperlink provides additional detail. From the table, the default assumptions suggest that 0.09 \$/kg of the cost is associated with carbon capture (capital, variable O&M, fuel), while the remaining cost of 0.07 \$/kg is for the sequestration (pipeline, disposal well). The results in this section are also available in units of \$/tC (to view, click on the specific unit along the vertical axis).

## Storage and Delivery

Clicking on the **Storage and Delivery** tab at the top of the screen advances the user to the screen shown in Figure 9.7.  $H_2$ Sim provides nine options for storing and distributing the hydrogen (Table 9.1). Each of the nine options, illustrated by a column in Figure 9.7, includes four

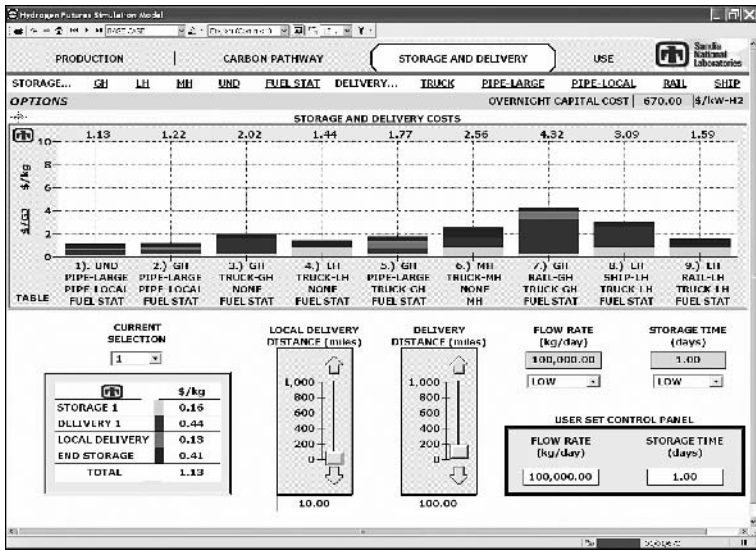


Figure 9.7. Storage and delivery screen.

Table 9.1. Distribution options in H<sub>2</sub>Sim

Option	Storage	Transport 1	Transport 2	Fueling station
1	Underground, Gaseous	Pipeline, Large	Pipeline, Local	Gaseous
2	Tanks, Gaseous	Pipeline, Large	Pipeline, Local	Gaseous
3	Tanks, Gaseous	Truck, Gaseous	None	Gaseous
4	Tanks, Liquefied	Truck, Liquid	None	Liquefied
5	Tanks, Gaseous	Pipeline, Large	Truck, Gaseous	Gaseous
6	Metal hydride	Truck, Metal hydride	None	Metal hydride
7	Tanks, Gaseous	Rail, Gaseous	Truck, Gaseous	Gaseous
8	Tanks, Liquefied	Ship, Liquid	Truck, Liquid	Gaseous
9	Tanks, Liquefied	Rail, Liquid	Truck, Liquid	Gaseous

steps: storage on site prior to transport (if necessary), primary transport method, secondary transport method, and fuel station costs.

While this screen, Figure 9.7, shows the costs for all nine options, the user must specify which option to use as the basis for calculating total costs of delivered hydrogen. Option 1 is the default scenario (underground, gaseous storage, transport by large pipeline connected to smaller, local pipelines, and storage at the fueling station in gaseous form). To select one of the other options, use the pull down menu on

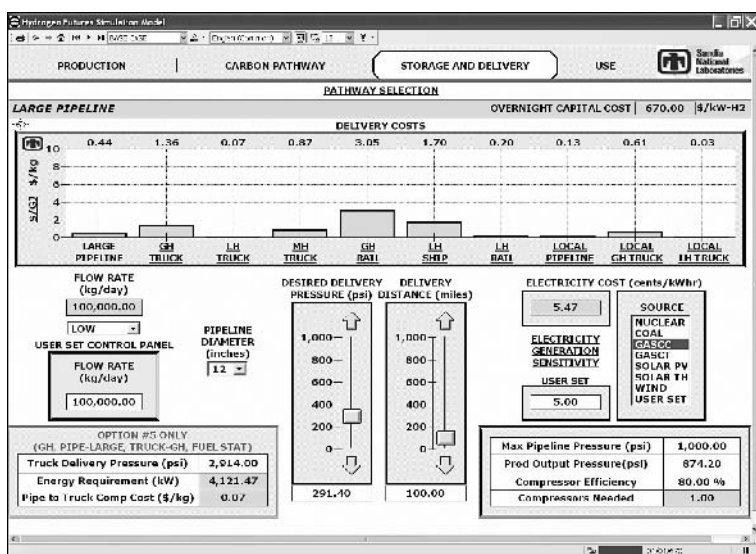


Figure 9.8. Hydrogen pathway sensitivity screen (large pipeline screen).

the left-hand side of the screen, labeled **Current Selection**. The table located below this pull down menu reports the costs associated with the selection made.

In addition to selecting the mode of storage and transport, the **Storage and Delivery** screen allows for considerable sensitivity analysis of the key variables affecting distribution, including distance (both primary and secondary), production flow rate, and storage time. Clicking specific storage or delivery modes along the top of the screen provides access to additional assumptions. For example, clicking on the **Large Pipeline** link allows one to change assumptions about flow rate, pipe size, delivery pressure, compressor efficiency, and electricity price (Figure 9.8).

The Elsevier Edition 2.2 of H<sub>2</sub>Sim does not allow the user to examine the specific characteristics of the storage and delivery options. A full version of H<sub>2</sub>Sim is required.

## End Use

The final section of the model is the End Use section. This version of H<sub>2</sub>Sim allows the user to compare the economics and carbon emissions from a variety of existing vehicle technologies (ICE vehicles, hybrids, and EV vehicles) with projected 2020 vehicle technologies (FCV, FCV OB, and direct combustion H<sub>2</sub>Hybrid). While hydrogen may be used for

commercial and residential stationary applications as well, these options are not included in this version of H<sub>2</sub>Sim.

Figure 9.9 illustrates the FCV screen in the End Use section. There are separate screens for each vehicle type. The current technology options are on the left-hand side of the **Total Vehicle Costs** graph (yellow background); future technologies are on the right-hand side (gray background). Vehicle costs, initially displayed in terms of cents per mile to operate, include capital, operating (maintenance, license, and insurance), and fuel costs. The costs are broken down and color coded by category. To view annual results, click on the **\$1000/year** hyperlink on that graph.

Each of the end-use screens shows basic assumptions about annual maintenance, insurance, license and registration costs, vehicle price, efficiency relative to the ICE vehicle (default ICE efficiency is 27.8 mpg), interest rates, amortization period, and annual miles driven. For ICE, hybrid vehicles, and FCV with onboard reformation of gasoline, wholesale gasoline price (before taxes) also is displayed. For the hydrogen vehicles, the user selects the source of hydrogen production. The resulting delivered cost of hydrogen is shown below the **Hydrogen Source** box.

For example, in Figure 9.9, reformation is selected, along with Option 1 for storage and delivery (gaseous storage with large regional

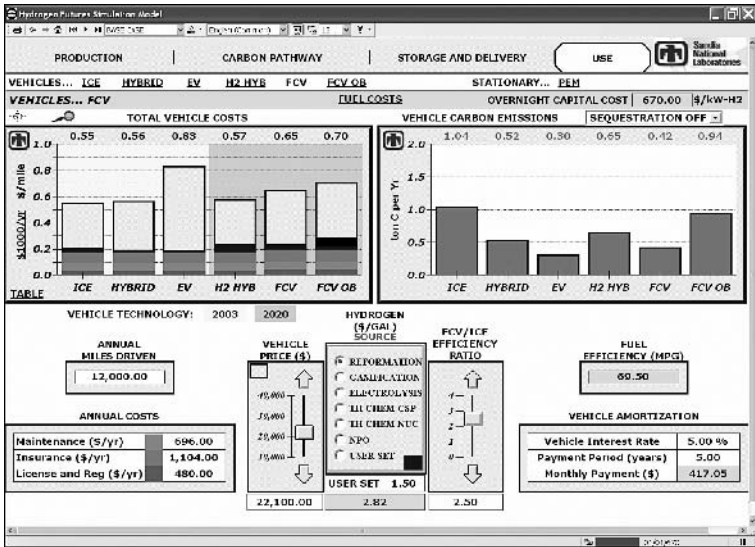


Figure 9.9. End use screen (fuel cell vehicle sensitivity screen).

pipelines connected to smaller pipelines and gaseous fueling stations) selected in the **Storage and Delivery** section of the model. This example also assumes no carbon capture and storage (upper right corner of screen via pull down menu). The user also may set the delivered hydrogen cost directly on this page with the **User Set** option. Finally, the graph on the upper right displays the projected carbon emissions for each vehicle type for the selected assumptions. Because each hydrogen production option has a different carbon profile, projected carbon emissions will vary as the user clicks on different hydrogen options. For example, selecting the thermochemical options for hydrogen production results in zero carbon emissions.

### **At What Gasoline Price Could Fuel Cell Vehicles Using Hydrogen From Coal Gasification Compete With Current Technology ICE Vehicles?**

The base case results suggest FCVs will have a difficult time competing with current technology ICE vehicles; the FCV would cost about 9 cents per mile more to drive. One option for making the FCV more attractive would be if gasoline prices were higher, either due to market forces or as a result of government action. This example provides a step by step guide to finding the necessary gasoline price at which FCVs could compete.

- Step 1: Reset and run the model to its default stopping point (670 \$/kW-H<sub>2</sub>).
- Step 2: Go to the **FCV** screen within the **End Use** section.
- Step 3: Select **Gasification** as the hydrogen source.
- Step 4: Go to **ICE** screen within the **End Use** section. Using the slider, increase the price of gasoline, observing the effect on ICE vehicle costs. Once the top of the slider is reached, continue increasing the assumed gasoline costs by 25 cents per gallon by typing numbers in the box below the slider until the ICE vehicle costs are equal to the FCV costs (3.50 \$/gallon). This result implies wholesale gasoline prices would have to increase by about 2.50 \$/gallon for the FCV to compete with the ICE technology.
- Step 5: Return the price of gasoline to 0.99 \$/gallon and experiment with other key assumptions that could make the FCVs competitive (efficiency, vehicle price, hydrogen price).

There are other slight variations between end-use options. The FCV OB screen contains an additional slider for the reformer cost. The EV

screen includes detail about the electricity generation source, allowing the user to select the electricity source. As with other parts of the model, this screen has a hyperlink to the **Electricity Generation Sensitivity** section of the model (not available in Elsevier Edition 2.2). Changing the electricity source also will impact carbon emissions.

## **Conclusion**

The H<sub>2</sub>Sim User's Guide provides the first-time user with the basic information required to run H<sub>2</sub>Sim, change key assumptions, and use more advanced options. Once the user understands the basic functions, H<sub>2</sub>Sim can be employed to explore a wide variety of scenarios.

Part V

**Conclusion and Discussion**

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## Chapter 10

# From Here to There: the Transition to a Hydrogen Future

The gasoline engine is entrenched firmly in our culture. The inertia of the current transportation system is huge. Doubters of a hydrogen future argue it will be extremely difficult, if not impossible, to move away from our current reliance on gasoline-powered engines until such time as we simply run out of fuel or until gasoline just becomes too expensive.

And yet, evidence is clear that we need to begin the transition from gasoline-powered vehicles as soon as possible. Hydrogen-powered vehicles offer a way forward. Clearly, many companies and governments believe in the hydrogen option. There is no other way to explain the vast sums of money that companies are investing in technologies ranging from fuel cell vehicles to mobile phone charging systems to military power units.

Interest in hydrogen as an energy carrier has grown for three main reasons: (1) scarcity and distribution of fossil fuel resources; (2) energy security; and (3) local and global environmental concerns. Significant barriers to a hydrogen-based economy certainly exist. The wide-scale implementation of hydrogen technologies will require widespread availability of hydrogen. Doubters note this is a classic chicken-and-egg problem. Consumers will not buy these technologies unless assured of a stable and economical supply of hydrogen. And hydrogen would not be available for consumers unless hydrogen producers and distributors are convinced they will be able to sell the hydrogen.

A hydrogen future may promise more benefits than can be delivered, however. The hydrogen first must be produced, liberating it either from water or hydrocarbon (fossil fuel) chains. One possible hydrogen source is natural gas. But there are several types of vehicles that now can run on compressed natural gas. Supplying natural gas for these vehicles is more straightforward than supplying hydrogen for a fuel cell vehicle (FCV) or hybrid hydrogen (H<sub>2</sub>Hybrid) vehicle. Likewise, considerable

energy is needed to separate hydrogen from water using electrolysis. Does it really make sense to generate electricity, which is often less than 40% efficient, for use in electrolysis? The answer is, "It depends." Using hydrogen produced by electrolysis to generate electricity for one's home would not be logical, as it would be far more efficient just to use the electricity in the first place.

And yet, because of the three reasons listed earlier, the widespread use of hydrogen in the transportation and other sectors is an appealing possibility. But first, the chicken-and-egg problem must be resolved. General Motors can push to have commercially viable FCVs in 2010, but consumers will not purchase them without reliable access to hydrogen-fueling stations. Likewise, without some type of government regulation and promotion of a hydrogen future, it is hard to envision how fueling stations would develop without demand from end users.

Fuel cell or H<sub>2</sub>Hybrid vehicles may make little sense if gasoline is relatively cheap and abundant. The confluence of several key factors in 2005 and 2006 led to inflated gasoline prices worldwide, but one should not assume this is the new status quo. Gasoline prices have been high in the past, only to recede to lower levels as market fundamentals reassert themselves. When gas prices fall again, interest in hydrogen may wane in countries - including the United States - that have relatively low gasoline taxes.

Despite these challenges to a hydrogen future, several potential paths forward are evident. The first is the gradual introduction of FCVs or H<sub>2</sub>Hybrid vehicles in the United States starting around 2020. Hydrogen initially would be produced at decentralized locations, most likely existing fueling stations. As the new technologies capture broader market shares, a more centralized system of hydrogen production and distribution would evolve. In this stage, the hydrogen would be produced from coal gasification or possibly thermochemical processes. If one of the goals of this hydrogen future is to have carbon-free vehicles, it is imperative that the coal gasification includes carbon capture and sequestration. Implementing this vision in the United States would address all three purposes listed earlier for pursuing a hydrogen future. The US dependence on scarce oil reserves, and therefore its reliance on unstable oil-producing countries, would be reduced. And local and global environmental concerns would lessen, since oil-based transportation sector is a major source of pollutants.

The second path forward involves the European Union (EU). While the first path focuses on implementing the hydrogen vision in the United States, action may occur first in another country or region facing similar concerns, such as Europe. Europeans have shown a willingness to enact policies aimed at controlling vehicular use and emissions, including high

gasoline taxes and strong vehicular emission standards for carbon dioxide. On the second path, the introduction of fuel cell or hybrid hydrogen technologies is encouraged by a strong carbon-emission trading scheme that seeks to reduce carbon emissions using tradeable, marketable permits that reward innovators.

The third path is one in which a rapidly developing country, such as China, whose transportation infrastructure is less developed and hence less ingrained, moves first to a hydrogen-based system. Cars may not even be the main, or initial, focus of this path. Rather, the transition may begin with fuel cell scooters and bikes. For China, with its vast coal resources, lack of domestic oil, and serious pollution concerns, this path has a strong appeal. The result could be a dominating lead in future fuel cell markets.

For every path forward, some caveats are necessary. First, implementing a hydrogen future will require government policies and assistance. The gasoline-powered engine has too strong a stranglehold on the existing infrastructure for private companies alone to spearhead the transition. Governmental involvement is justified because of the long-term benefits of moving away from an oil-based economy. Types of governmental assistance required include: funding at least part of an initial national system of refueling stations; incentives for consumers to purchase the new technologies; and possible mandated targets for FCV production, such as 10% of vehicle sales by 2030.

Second, unproven technologies must not be forced into the marketplace. Controlled release of prototypes, such as Honda's placement of an FCX with a California family, makes sense if the company receives useful feedback and experience. But the extensive introduction of inferior products, possibly due to a strong government push, could only give a black eye to the whole concept. If consumers are burned by early versions of a new technology, they may reject later, improved models. The year 2020 appears to be a sensible time frame for widespread introduction of fuel cell and hybrid technologies, based on progress to date on the various technologies.

The third caveat is that the transition to hydrogen will not happen overnight, but likely will take several decades. Market penetration of new technologies typically follows an S-shaped curve (Figure 10.1). The "innovators," those who like new products/inventions and are willing to take on the incumbent risks, are the first purchasers of new technologies. They are followed by "early adopters" who like new technologies but usually wait until prices begin to drop. Most consumers, however, are risk-averse and do not rush out to purchase a new technology. As market share for the new technology reaches about 10%, penetration sharply increases. Any new technology can expect to achieve a

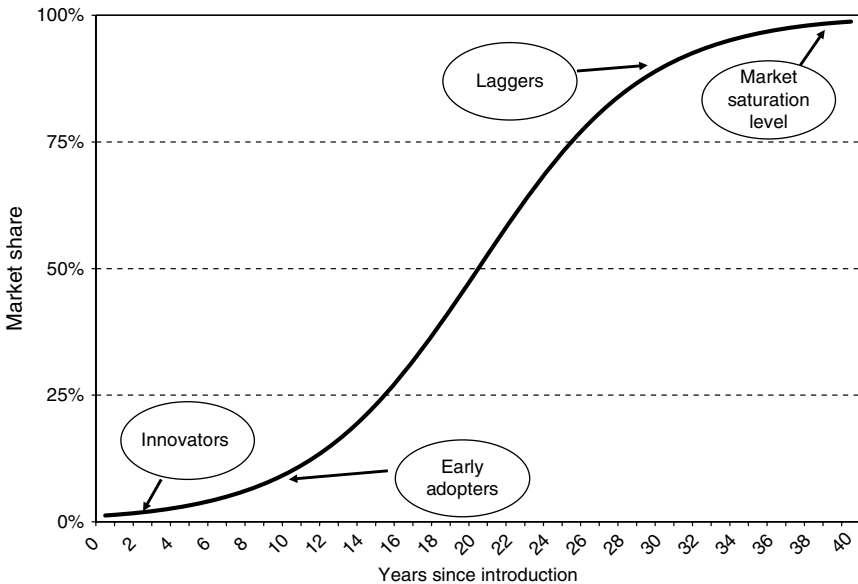


Figure 10.1. Market diffusion curve for new technologies.

maximum saturation level. While some technologies, such as refrigerators, achieve 100% market share, other technologies typically do not. Not all houses, for example, have DVD players or computers.

The specific shape of the market diffusion curve is dependent on several factors. For hydrogen, a key factor will be supply and demand considerations in the oil markets. Oil-producing countries will not simply give up market share to a new technology. Unless markets have entered a period of scarcity marked by increasing prices at the time hydrogen vehicles are introduced, decreasing demand for oil naturally would lead to plunging world oil prices as production exceeds demand. In this new world, oil-producing countries would have two choices: cut back production in an effort to maintain higher prices and hence export revenues, or let oil prices fall to make the hydrogen option the more costly option. Substantially decreased gasoline prices could stall the transition to hydrogen, but cheap oil will not last forever.

### **A Decentralized Approach to Hydrogen Production for the United States**

The first path forward involves the decentralized production of hydrogen from natural gas or electrolysis at fueling stations in the United

States. This approach may not achieve all the stated objectives for transitioning to a hydrogen economy. Specifically, much of the hydrogen production will rely on the heavy use of fossil fuels, whether produced from natural gas reformation or electrolysis using largely grid-supplied electric power. A distributed hydrogen system will, however, reduce the transport sector's reliance on imported sources of petroleum.

A sufficient number of fueling stations would have to sell hydrogen for consumers to be comfortable owning a FCV or H<sub>2</sub>Hybrid vehicle. Matthew Fronk, lead engineer for fuel cell development at General Motors in Honeoye Falls, New York, argues that launching a national hydrogen infrastructure in the United States would require making hydrogen available at about 7% of the 169 000 existing fueling stations across the country (Fronk 2006). Fronk assumes the need for a hydrogen-fueling station every 24 miles along each of America's 130 000 miles of highways. In urban areas where some 70% of the US population resides, Fronk assumes a station is needed approximately every two miles, so drivers pass a hydrogen-fueling station on the way to work. This would require about 6500 urban stations and 5200 stations on highways. Fronk assumes retrofitting each of the 11 700 fueling stations with hydrogen-refueling capabilities will cost about \$1 million, not including the cost of the hydrogen production system, for a total national commitment of \$10–15 billion. While this initial investment is sizable, the amount is relatively small compared to current US expenditures on highways and roads, which totaled \$138 billion in 2003 (Census Bureau 2006).

Joan Ogden at University of California, Davis, also has studied infrastructure requirements in the early phases of a hydrogen economy. In a study of the Sacramento area, Ogden (2005) estimated how many hydrogen-fueling stations would be needed to minimize drive time. She concluded that 10–30% of gas stations would have to offer hydrogen, or 32–96 stations. There is not, however, a large difference in travel time for the two scenarios because of Sacramento's population density. With only 10% of stations offering hydrogen, the average time for anyone to reach a station would be about 3 minutes, compared to just 2 minutes for the 30% scenario.

Hydrogen production costs at the decentralized fueling stations will be higher than those of large-scale centralized facilities. Chapter 6 discussed hydrogen production options and noted the relationship between capital cost and hydrogen production rate. Specifically, it estimated the capital cost for a large 100 000 kg/day steam methane reformation (SMR) facility would be \$69.5 million, or approximately 500 \$/kW-H<sub>2</sub>. The capital costs for a smaller 1000 kg/day facility that could be located at a fueling station are estimated at \$2.8 million, or about 2000 \$/kW-H<sub>2</sub>. Using this estimate of capital costs, the Hydrogen Futures Simulation

Model estimates that each kilogram of H<sub>2</sub> would cost about \$2.29.<sup>1</sup> Adding the estimated cost of dispensing hydrogen at a fueling station (0.41 \$/kg) increases the cost before taxes or profits to 2.70 \$/kg. This result is also highly sensitive to the price of natural gas. Each \$1 increase in natural gas costs from the assumed base of 5.92 \$/MBtu increases the hydrogen cost by 0.16 \$/kg. These are not minor caveats; wholesale gasoline costs during 2005 averaged 1.73 \$/gallon and the US Department of Energy's February 2006 forecast for 2030 was 1.59 \$/gallon (DOE 2006).

Hydrogen produced at centralized locations would be cheaper. The Hydrogen Futures Simulation Model suggests that hydrogen could be produced for as low as 0.81 \$/kg from large-scale, centralized coal gasification.<sup>2</sup> Hydrogen produced from electrolysis is significantly more expensive, ranging from 2.33 \$/kg to a high of 12.43 \$/kg, depending on the source of electricity. The lower range assumes the electricity is from a newly constructed coal facility. The higher estimate assumes the electricity is from a newly installed solar photovoltaic system. Hydrogen produced from the reformation of natural gas at a centralized facility is the second-lowest cost option at 1.43 \$/kg, a result highly sensitive to the price of natural gas.

But unless the hydrogen is produced at the fueling station or even at the household level, there are also storage, distribution and fueling station costs. These expenses add another 1.13–1.44 \$/kg to the total hydrogen cost.<sup>3</sup> For the case of hydrogen produced from a coal gasification plant at a cost of 0.81 \$/kg, the total delivered cost likely would range from 1.94 to 2.25 \$/kg once economies of scale are achieved. Because these economies of scale could not be realized in the early days of the hydrogen economy, however, they cannot validly be compared to the higher projected (2.70 \$/kg) decentralized costs.

As emphasized in Chapter 8, fuel is not a major component of total driving expenses and is unlikely to make or break the economic viability of hydrogen vehicles. For the least expensive hydrogen production option (centralized coal gasification) with pipeline transportation, the H<sub>2</sub>Hybrid vehicle is already economically competitive (0.56 \$/mile) with 2005 internal combustion engine (ICE) vehicles (0.55 \$/mile). A FCV, with a base efficiency 2.5 times that of a comparably sized ICE vehicle and costing \$4100 more, has an estimated operating cost of \$0.62–0.70 per mile – at least 7 cents higher than the ICE vehicle. The fuel cost

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<sup>1</sup> Each kg of hydrogen has the approximate energy content of a gallon of gasoline.

<sup>2</sup> The user can verify all numbers using the run-time version of H<sub>2</sub>Sim included with this book.

<sup>3</sup> These estimates are for the “low” hydrogen production scenarios of Chapter 7.

per mile for both vehicles is identical, however, even with an assumed gasoline cost of 0.99 \$/gallon,<sup>4</sup> the default H<sub>2</sub>Sim assumption. While consumers may focus on fuel costs, the vehicle's purchase price, maintenance, and insurance are significantly more expensive. Manufacturers and the government should focus on ensuring the vehicle price is competitive with existing vehicles. Alternatively, these vehicles will have to offer something that conventional vehicles cannot, such as remote electricity hookups, cleaner air, or a new excitement factor.

The two options for hydrogen production at the station level are reformation of natural gas or electrolysis. Doubters of the decentralized approach will note the concern about natural gas availability and electricity generation capacity. Confronting those doubts requires understanding the potential increase in demand for natural gas that would be associated with the move to a hydrogen future.

Consider two scenarios for the introduction of FCV or H<sub>2</sub>Hybrid vehicles into the United States market in 2020 (Figure 10.2). Both scenarios assume market saturation occurs at 80% of new vehicle sales. It seems unlikely that gasoline-powered vehicles would be replaced completely by FCV. Residents of rural areas, where hydrogen would not be available widely, would be likely holdouts. The first scenario assumes a moderately paced introduction of FCV starting in 2020. The second

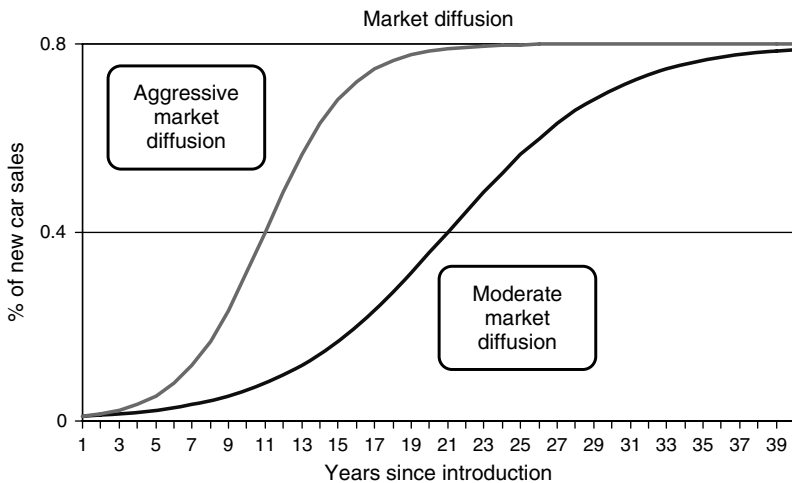


Figure 10.2. Two market diffusion scenarios for the decentralized scenario.

<sup>4</sup> The estimate for 2020 in the Annual Energy Outlook 2004.

scenario assumes a more aggressive transition, marked by higher consumer demand for the new technology. This could be purely market-driven or the result of orchestrated government policies.

Both scenarios include all types of passenger vehicles, including mini-vans and light duty trucks. A key difference between the two scenarios is the assumed time required to go from 10 to 90% of the likely market share at saturation. The moderate growth scenario assumes it takes 20 years for market share to go from 10 to 90%; the aggressive growth scenario assumes this happens in 10 years. Table 10.1 summarizes the results from the two scenarios.

### *Moderate growth scenario*

These results illustrate the lengthy time required for the transition to hydrogen. The hydrogen vehicles are introduced in 2020. By 2030, FCV account for 8% of all vehicle sales (Table 10.1). The share increases to 40% by 2040 and 72% by 2050. Even though the market share of new vehicles reaches 40% by 2040, FCVs account for just 18% of all vehicles on the road that year because of slow turnover in the existing car fleet.

Table 10.2 also shows the natural gas or electricity requirements required to produce hydrogen for the fleet of vehicles and compares these requirements to projected use of natural gas and electricity for other sectors in the United States. For the moderate growth case, natural gas requirements for the entire projected fleet of FCVs accounts for 1%, 7%, and 19% of total projected natural gas consumption in 2030, 2040, and 2050, respectively. These results suggest that the additional natural gas requirements in the early stages of the transition to a hydrogen economy would not add considerable extra demand on the natural gas markets. By the third decade of the transition, one would expect a more centralized system of hydrogen production to develop, particularly for the more heavily populated areas.

Table 10.1. Fuel cell vehicles (FCV) on road, moderate growth case

YEAR	Vehicles on road (millions)				FCV Sales			
	Cars		Light trucks		Cars		Light trucks	
	ICE	FCV	ICE	FCV	millions	% of ICE	millions	% of ICE
2003	131.4	0.0	107.0	0.0	0.0	0.0	0.0	0.0
2020	140.5	0.1	163.4	0.1	0.1	1.0	0.1	1.0
2030	143.4	3.2	175.1	4.2	0.7	8.0	0.9	8.0
2040	133.3	22.8	162.0	29.6	3.7	40.0	4.9	40.0
2050	95.0	71.7	113.2	91.4	7.1	72.0	9.4	72.0

Table 10.2. Projected natural gas or electricity requirements for FCV with comparison to existing demand, moderate growth case

	Reformation				Electrolysis				
	Cars	Light truck	Total	% of total natural gas demand	Cars	Light truck	Total	% of total electricity demand	Electricity requirement (GWh)
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2099
2030	0.1	0.2	0.3	1.1	0.2	0.3	0.6	2.1	84727
2040	0.8	1.2	2.1	7.1	1.6	2.4	4.0	12.9	595813
2050	2.6	3.8	6.4	19.0	5.0	7.5	12.5	31.5	1851932

Table 10.2 also shows how much electricity is needed to generate enough hydrogen from electrolysis for the entire fleet of vehicles. For ease of comparison with the earlier results for natural gas reformation, these results assume electricity from newly constructed, highly efficient combined cycle facilities fueled with natural gas.<sup>5</sup> Producing hydrogen from electrolysis in this manner would increase natural gas demand by 2, 13, and 31% of total projected demand in 2030, 2040, and 2050, respectively. This is higher than the forecasted extra demand for the natural gas reformation case, due to the inherent inefficiency of generating electricity. This does not need to be the case; a new fleet of nuclear plants could just as easily provide the electricity. This new demand is equivalent to building by 2050 more than 230 new 1000 MW nuclear or coal-fired facilities, a common size for these types of plants.

#### *Aggressive growth scenario*

Market share increases significantly faster in the aggressive growth scenario (Table 10.3). By 2030, the new vehicles capture 40% of the new vehicle market share, compared to just 8% in the moderate growth case. The market share reaches 79% by 2040 and 80% by 2050, the maximum assumed saturation level for hydrogen vehicles. In this aggressive scenario, hydrogen vehicles account for 72% of all vehicles on the road by 2050.

Even with this much faster rate of introduction, the natural gas required to produce all the hydrogen for these vehicles is just a fraction of the total demand projected for other sectors in the United States (Table 10.4). The projected increase in demand is 4% in 2030, increasing

<sup>5</sup> Assumes a heat rate of 6800 Btu/kWh.

Table 10.3. Fuel cell vehicles (FCV) on road, aggressive growth case

Year	Vehicles on road (millions)				FCV Sales			
	Cars		Light trucks		Cars		Light trucks	
	ICE	FCV	ICE	FCV	millions	% of ICE	millions	% of ICE
2003	131.4	0.0	107.0	0.0	0.0	0.0	0.0	0.0
2020	140.5	0.1	163.4	0.1	0.1	1.0	0.1	1.0
2030	134.4	12.3	163.1	16.2	3.5	40.0	4.6	40.0
2040	85.7	70.4	101.1	90.5	7.3	79.0	9.7	79.0
2050	48.6	118.1	56.9	147.7	7.9	80.0	10.5	80.0

Table 10.4. Projected natural gas or electricity requirements for FCV with comparison to existing demand, aggressive growth case

Year	Reformation				Electrolysis				
	Cars	Light truck	Total	% of total natural gas demand	Cars	Light truck	Total	% of total electricity demand	Electricity requirement (GWh)
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2099
2030	0.4	0.7	1.1	4.0	0.9	1.3	2.2	7.5	324619
2040	2.5	3.8	6.3	18.9	4.9	7.4	12.3	31.3	1828514
2050	4.2	6.2	10.4	27.7	8.2	12.1	20.4	42.8	3016040

to 19% by 2040 and 28% by 2050. As with the moderate growth case, these numbers also show the feasibility of relying on natural gas in the early stages of this scenario. The pace of sales in this more aggressive scenario also would support a more centralized system faster than would be the case for the moderate growth scenario.

If the aggressive case relied on hydrogen produced by electrolysis from natural gas-fired plants, the demand for natural gas would increase 8% by 2030, 31% by 2040, and 43% by 2050. Again, these numbers are significantly higher than those for the reformation of natural gas due to the inefficiency of electrical generation. In terms of new generating facilities, this increased demand is the equivalent of 382 new 1000 MW nuclear or coal-fired plants by 2050.

### A Push from Carbon Markets in the European Union

Global efforts to reduce carbon dioxide and other greenhouse gas emissions also could be the pathway to a hydrogen future. Several countries

are obligated under the terms of the Kyoto Protocol to reduce emissions of carbon dioxide and other greenhouse gases to below 1990 levels by 2012. To help meet its collective target at the lowest possible cost, the member nations of the European Union (EU) established an emissions-trading scheme (EU ETS). This system could improve the economic competitiveness of the hydrogen option by establishing a market price for carbon that ultimately will make gasoline more expensive.

The EU ETS has grown steadily since its 2005 inception. Under the plan, each EU member nation is granted an annual allocation of permits. The system currently covers some 11 500 energy-intensive installations across the EU, which jointly represents about half of European emissions (European Commission 2006). The initial program did not include the transportation sector. As the allowance markets evolve, it is reasonable to expect countries to consider expanding the system to further reduce emissions from all sectors.

Emission-trading schemes allow countries and companies to minimize the costs of compliance with regulatory targets. Those companies that can reduce emissions cheaply will do so if they can sell their excess permits at a higher price. In the United States, markets for sulfur dioxide and nitrous oxides are well-established and have played a key role in reducing emissions of those pollutants. Since trading in the EU ETS commenced in 2005, volume has increased steadily from 94 million tons (CO<sub>2</sub> equivalents) to 799 million tons in 2006 (Point Carbon 2006). A survey of market participants conducted by Point Carbon (2006) shows that a majority of market participants expect prices will continue to increase as the lowest-cost options for reducing emissions are realized and as market demand continues to strengthen. A potential problem with the current EU trading system may be an oversupply of permits, which could lead to depressed prices post-2006.

As the EU trading scheme gains widespread acceptability, it could expand to other sectors and countries, establishing an international price for carbon. An international carbon price would improve the overall economic viability of the hydrogen economy. The transport sector is an obvious target for expansion of the program. Negotiations have begun on expanding the system to include aviation sources after the original Kyoto commitment period. The International Civil Aviation Organization (ICAO), for example, notes that "an emissions trading system... would be a cost-effective measure to limit or reduce CO<sub>2</sub> emitted by civil aviation in the long term, provided that the system is an open one across economic sectors" (ICAO 2006). British Airways also supports the use of the ETS: "Over the long term, we support the incorporation of aviation into an international system of emissions trading for greenhouse gases" (British Airways 2006).

Expanding the system to include vehicles is technically feasible. For example, each country could be allocated enough permits to cover a certain percent of current or projected emissions from vehicles (such as 95% of 2006 levels). While governments could enact emission standards or use other regulatory tools to ensure compliance, they also could pass along the international price of a carbon permit in the form of a fuel tax at the pump. The government of each country would be ultimately responsible for assuring there were sufficient permits to cover that country's allocation. If a country did not have enough permits, they would have to buy permits on the open market. This would drive up the international price of permits, as well as the price at the pump.

Europeans are accustomed to the use of gas taxes as a policy option to control vehicular use. In many European countries, prices at the pump are more than \$2 per gallon higher than in the United States, where any mention of gasoline taxes is politically taboo. Actual permit prices for the EU ETS averaged €20 (\$25.45) per metric ton of carbon dioxide (MtCO<sub>2</sub>) in 2005 (Figure 10.3). Passing this cost along to the consumer would increase gasoline prices by about 0.23 \$/gallon.<sup>6</sup> While prices fell

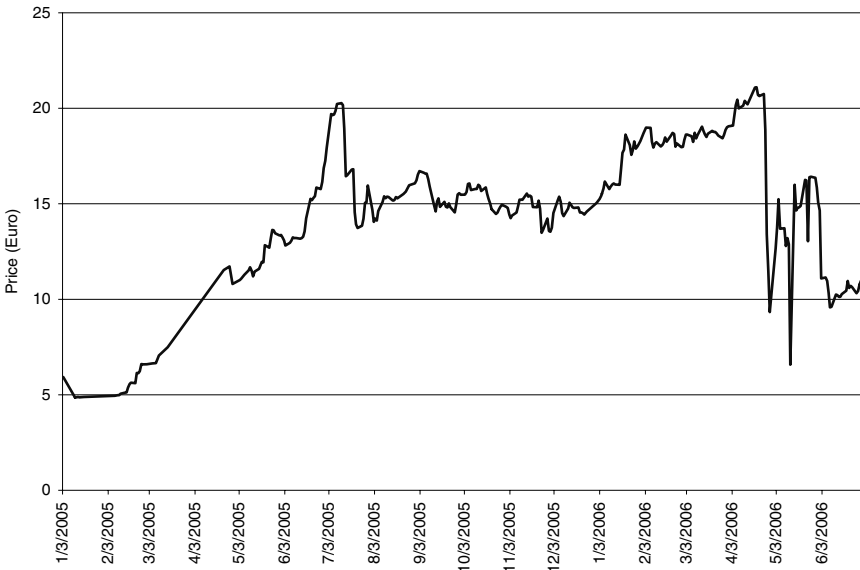


Figure 10.3. Daily closing prices for emission permits in the EU ETS.

(Source: Bloomberg, 2006.)

<sup>6</sup> Assumes each gallon of gasoline releases 19.564 lbs CO<sub>2</sub> per gallon [2.35 kg CO<sub>2</sub>/liter].

in 2006 due to concerns about an oversupply of permits, the majority of market participants in the Point Carbon survey believe prices will rebound and will increase. As permit prices increase, gasoline taxes also would increase. A \$100 per metric ton permit price would add 0.91 \$/gallon.

### **The Push from Rapidly Developing Countries**

The hydrogen transition could follow many other pathways. The decentralized fueling station approach probably makes the most sense for a country such as the United States. However, it is possible that the transition will not begin in industrialized countries. A country such as China – with a huge appetite for cars but few oil reserves – could make the move first. For the Chinese, it may make sense to move immediately to a centralized system. China has proven its willingness to take on large projects. The Three Gorges Dam on the Yangtze River, for example, required the relocation of upward of 1.2 million people when some 300 miles of the Three Gorges area was turned into a reservoir. The Chinese also have initiated a decades-long giant water diversion project that ultimately will connect China's major rivers and that requires the construction of three south-to-north canals. Once completed, the diversion canals are expected to assure adequate supplies to water-starved northern areas. Why not a hydrogen infrastructure that utilizes China's vast coal resources and would assure the Chinese a domestic means for fueling their transport needs? China's recent ventures to secure future oil supplies emphasize the country's transport concerns. China could realize another benefit from a hydrogen infrastructure: the Chinese could be the ones to produce the FCVs, giving the country a huge export opportunity.

The transition might not start with cars. Scooters are an inexpensive substitute for cars in many countries. Several companies believe fuel cell scooters can be a viable option in these countries. Gasoline-powered scooters have been banned from cities such as Beijing and Shanghai because of the amount of pollution they spew. These bikes and scooters are very popular in Beijing, where the scooters sell for less than \$300. In response to such bans, a market in electric bicycles and scooters has developed. While these bikes do not travel at the speeds of scooters, they are considerably cheaper. *China Daily* (2006) reports that China plans on producing 30 million electric bikes per year by 2010 and notes that "electric bike production in China accounts for about 90% of the world's total." While these bikes are not powered by fuel cells, they do offer speedy transportation at a fraction of the cost of automobiles.

Several companies are developing fuel cell scooters. One company, Vetrix, located in the United States and Europe, already is promoting

what it refers to as “the world’s first full-size, high-performance, long-range, low-emission electric scooter.” Rather than plugging the scooter in to recharge, the batteries are continuously charged by onboard fuel cells. Vetrrix’s stated plan is to heavily market the scooter to commuters in major cities by 2008 to 2010. The real benefit is that the fuel cell is sized not to power the scooter, but rather just to charge the batteries. The company expects the scooter to have a top speed of 62 mph (100 km/hr) and to accelerate from 0 to 60 mph (0 to 100 km/hr) in about 8 s.

In China, the Vetrrix scooter likely will face some tough competition from several indigenous electric bikes and scooters. A serious issue, however, is the already-overloaded Chinese power grid. The Chinese literally cannot build new power plants fast enough to handle increasing demand for electricity. Drennen (2005) estimates the Chinese will require additional capacity requirements of 320 to 750 GW by 2025. This implies the need for 16–38 new 1000 MW electricity-generating facilities every year – without factoring in any additional demand from the transport sector. Fuel cells could help to fill this market need.

Since China is well-endowed with coal resources, coal likely would be the hydrogen source. This poses an interesting challenge. Greater coal usage would lead to increased emissions of carbon dioxide. At the same time, coal use would reduce competition for foreign sources of oil and probably lead to less regional air pollution because FCVs (cars or scooters) operate more cleanly than gas-powered alternatives.

Taiwan also is looking at fuel cell scooters to help solve many of its transportation and environmental problems. Scooters accounted for 65% of all vehicles in Taiwan in 2001, or approximately one scooter for every two people (Tso and Chang 2003). Many of these scooters have heavy-polluting two-stroke engines, that, according to Tso and Chang, produce three to seven times more pollution per kilometer than a typical car. In an attempt to clean its air, Taiwan has banned the sale of two-stroke engines, set goals for the production of electric scooters, and offered incentives for electric scooter purchases. Taiwan’s “Electric Motorcycle Development Action Plan” of 1998 set tight limits on two-stroke scooters and projected that electric scooters would comprise 40% of sales by 2006. However, consumer acceptance of electric scooters has been low due to the poor performance of lead-acid batteries and sparse availability of recharging stations. This opens the door for fuel cell scooters.

Asia Pacific Fuel Cell Technologies (APFCT) has developed a series of prototype zero emissions scooters (ZEV) for the Taiwanese and, potentially, other markets. According to the Taiwanese company, the most recent prototype, the ZEV IV.5, has a maximum speed of 52 km/hr, a driving range of about 60 km at a driving speed of 30 km/hr, and runs on pure hydrogen (APFCT 2006). Based on the company’s estimates,

this scooter has a fuel efficiency of 370 miles per kg H<sub>2</sub> (625 km/kg)! But the really unique feature of this scooter is its method of refueling, which contrasts sharply with the fueling station approach. Replaceable canisters store the hydrogen in a metal hydride. Each canister weighs about 4.5 kg and contains about 0.1 kg of hydrogen, enough to travel 60 km.<sup>7</sup> Theoretically, these canisters could be sold just about anywhere that demand exists.

## **Conclusion**

The transition from an oil-based to a hydrogen-based economy will not happen overnight, yet several paths to this hydrogen future are visible. For the first two paths forward (the US and European paths), distributed production of hydrogen at the fueling station is most practical. The cost of hydrogen production likely will be greater than the cost of centralized distribution, but will avoid the huge expenses associated with developing national-level hydrogen delivery systems. Once fuel cell or other hydrogen technologies capture a significant market share, a national, centralized approach to hydrogen production and distribution will make economic sense. For the third path (China or other rapidly developing country), centralized hydrogen production may make economic sense from the beginning.

While many studies focus on the industrialized markets, the transition may begin with rapidly developing countries, where the oil-based infrastructure is less advanced and where technological expectations may be quite different. For example, scooters and bikes are a way of life in many countries. Because existing two-cycle scooters are such heavy polluters, they have been banned in many places, opening up a real market niche for fuel cell powered scooters and bicycles. These countries could gain a lot of experience with fuel cell technology, and the manufacturers would garner a competitive lead in fuel cell technologies.

However the transition begins, it will take time. And strong governmental support will be needed to overcome huge inertia within the current system of gasoline-powered engines. Making the transition, however, is necessary. A hydrogen future offers many benefits – chief among them cleaner air and a reduced reliance on insecure supplies of fossil fuels – crucial to the future of the Earth and its people.

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<sup>7</sup> This is derived from APFCT's estimate of a fuel efficiency of 1.6 gH<sub>2</sub> per km and a range of 60 km at 30 km/hr.

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# Appendix<sup>1</sup>

## Executive Summary

The Electricity Generation Cost Simulation Model (GenSim) is a user-friendly, high-level dynamic simulation model that calculates electricity production costs for a variety of electricity generation technologies, including: pulverized coal, gas combustion turbine (CT), gas combined cycle (CC), nuclear, solar (photovoltaic [PV] and thermal), geothermal, and wind. The model allows the user to conduct quickly sensitivity analyses on key variables, including capital, operation and maintenance (O&M), and fuel costs; interest rates; construction time; heat rates; taxes; depreciation; and capacity factors. The model also includes consideration of a wide range of externality costs and pollution-control options for carbon dioxide, nitrogen oxides, sulfur dioxide, and mercury. Two different data sets are included in the model: one from the US Department of Energy (DOE) and the other from Platt's Research Group. Likely users of this model include executives and staff in the US Congress, the administration, and private industry (power plant builders, industrial electricity users, and electric utilities). The model seeks to improve understanding the economic viability of various generating technologies and their emissions trade-offs.

The base case results, using the DOE data, indicate that in the absence of externality costs, or renewable tax credits, pulverized coal and nuclear are the least cost alternatives at 4.5 and 5.3 cents/kWh, respectively. A complete sensitivity analysis on fuel, capital, capacity factor, and construction time shows that the results for coal and gas are much more sensitive to assumptions about fuel prices than they are to capital costs or construction times, while nuclear results are more sensitive to

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<sup>1</sup>This appendix was originally released as Drennen, T. E., A. Baker, W. Kamery. (2005). *Electricity Generation cost Simulation Model (GenSim)*. Sandia National Laboratories.

capital costs and construction times. The results also suggest that wind competes with coal or nuclear in areas of strong wind resources.

## **Introduction**

The Electricity Generation Cost Simulation Model (GenSim) is a user-friendly, high-level dynamic simulation model that calculates electricity production costs for a variety of electricity generation technologies, including: pulverized coal, gas CT, gas CC, nuclear, solar [photovoltaic (PV) and thermal], geothermal, and wind. The model allows the user to conduct quickly sensitivity analyses on key variables, including: capital, operating and maintenance (O&M), and fuel costs; interest rates; construction time; heat rates; taxes; depreciation; and capacity utilization factors. The model also includes consideration of a wide range of externality costs and pollution control options for carbon dioxide, nitrogen oxides, sulfur dioxide, and mercury. Likely users of this model include executives and staff in the US Congress, the administration, and private industry (power plant builders, industrial electricity users, and electric utilities). The model seeks to improve understanding the economic viability of various generating technologies and their emissions trade-offs.

GenSim is written in Powersim Studio Enterprise 2005,<sup>2</sup> a dynamic simulation-modeling software package. The model's easy-to-use policy screens allow the user to explore "what if?" questions, such as

- Under what conditions can nuclear power compete economically with pulverized coal plants – does it take installed capacity costs of less than \$1500 per kW?
- What capital costs (and/or capacity utilization with storage) allow solar PV to compete with pulverized coal facilities?
- What type of tax credits (cents/kWh) makes wind the least cost option?
- How might adoption of the administration's Clear Skies policy affect utility power plant investment decisions?

This chapter provides an overview of the model structure; base case results for two different data sets; detailed sensitivity analyses on capital costs, fuel prices, and construction times; and externality analyses for the four key pollutants.

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<sup>2</sup>Powersim Studio Enterprise 2005 is a product of the Powersim Corporation: [www.powersim.com](http://www.powersim.com)

## Model Structure and Assumptions

GenSim calculates projected levelized cost of energy (LCOE)<sup>3</sup> for a wide variety of electricity generation technologies: advanced coal, CC natural gas, natural gas combustion, nuclear, wind, geothermal, solar thermal, and solar PV.<sup>4</sup> All values are for new plants equipped with the best available pollution-control technologies (BACT).

GenSim includes two user data sets: Department of Energy, Energy Information Administration (EIA 2005a,b); and Platt's Research and Consulting Group (Platt's 2002). Table A1 summarizes the key assumptions about each technology for the two data sets.<sup>5</sup> The Platt's data does not include nuclear or geothermal cost estimates. While GenSim defaults to these assumptions, the user easily can vary the assumptions and view the implications for LCOE. For example, the user easily can explore the impact of extended project construction time on the projected LCOE or test the economic competitiveness of CC plants at higher projected natural gas costs. Table A2 summarizes the assumed fuel prices for each technology; the DOE estimates are their estimated prices in 2005.

LCOE often is used as an economic measure of electricity costs because it allows for comparing technologies with different capital and operating costs, construction times, and capacity factors. The LCOE calculation is given by

$$\text{LCOE} = \frac{I\text{FCR}}{Q} + \frac{\text{O\&M}}{Q} + \frac{E}{Q} \quad (1)$$

where  $I$  is the capital investment, including financing charges (interest rate initially set at 10%); FCR the fixed charge rate;  $Q$  the annual plant output (kWh); O&M the fixed and variable O&M;  $E$  = externality costs.

The fixed charge rate (FCR) is calculated using

$$\text{FCR} = \frac{\text{CRF}[1 - bT \sum_{n=1}^M V_n / (1 + d_n)^n - t_c]}{(1 - T)} + p_1 + p_2 \quad (2)$$

where CRF is the capital recovery factor;  $b$  the fraction of investment that can be depreciated;  $T$  the effective tax rate;  $M$  the depreciation period;  $V_n$  the fraction of depreciable base in year  $n$ ;  $d_n$  the nominal discount rate;  $t_c$  the tax credit;  $p_1$  the annual insurance cost;  $p_2$  the other taxes.

<sup>3</sup> Sometimes referred to as busbar or production costs.

<sup>4</sup> The costs given in this paper are for newest available technologies for each option.

<sup>5</sup> All dollar figures in paper are in 2003 dollars.

Table A1. Cost and performance characteristics for new generating plants (2003 \$)

	Capital (\$/kW)	Fixed O&M (\$/kW)	Variable O&M (\$/kWh)	Fuel (\$/MBtu)	Years to construct	Plant size (MW)	Average capacity factor (%)	Heat rate (MBtu/ kWh)
Nuclear								
DOE	1694	60.06	0.00044	0.43	6	1000	90.0	10 400
Platt's <sup>1</sup>	-	-	-	-	-	600	-	-
Coal								
DOE	1134	24.36	0.00406	1.29	4	600	85.0	8844
Platt's	1028	18.32	0.00183	0.81	3	400	85.0	9100
Gas CC								
DOE	517	10.35	0.00177	5.92	3	400	85.0	6752
Platt's	443	15.27	0.00204	3.31	2	400	85.0	7100
Gas CT								
DOE	356	9.31	0.00280	5.92	2	230	30.0	9183
Platt's	347	5.09	0.00046	3.31	1	120	10.0	10 900
Solar PV								
DOE	3868	10.34	0.00000	0.00	2	5	24.6	10 280
Platt's	7185	0.00	0.07839	0.00	1	5	25.4	0
Solar thermal								
DOE	2515	50.23	0.00000	0.00	3	100	33.0	10 280
Platt's	2514	20.36	0.00000	0.00	2	100	25.4	0
Geothermal								
DOE	2960	104.98	0.00000	0.00	4	50	86.0	45 335
Platt's <sup>1</sup>	-	-	-	-	-	-	-	-
Wind								
DOE	1060	26.81	0.00000	0.00	3	50	38.0	0
Platt's	896	0.00	0.01018	0.00	1	50	35.0	0

<sup>1</sup> Nuclear and geothermal cost data not provided for the Platt's data set.

Table A2. Fuel cost assumptions (2003 \$)

	DOE (\$/MBtu)	Platt's (\$/MBtu)
Nuclear <sup>1</sup>	0.43	-
Coal	1.29	0.81
Gas	5.92	3.31

<sup>1</sup> Nuclear cost data not provided for the Platt's data set.

Depreciation follows the depreciation method Modified Accelerated Cost Recovery System (MACRS). Under IRS regulations, most utility type investments use either a 15- or 20-year depreciation schedule. Certain investments, such as renewables, are allowed to use a 5-year depreciation schedule. The capital recovery factor (CRF) is calculated using

$$\text{CRF} = r \frac{(1+r)^n}{(1+r)^n - 1} \quad (3)$$

where  $r$  is the real discount rate (initially set at 10%) and  $n$  = plant life (initially 20).

Financing costs assume that capital expenditures are distributed uniformly over the time of construction.

GenSim considers externality costs for emissions of sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), carbon dioxide (CO<sub>2</sub>), and mercury (Hg). Externality costs are initially set to zero in the model.

Figure A1 shows a representative GenSim main busbar screen (nuclear). Hyperlinks along the top allow the user to change screens. For example, clicking on coal takes the user to the main coal screen. The graph illustrates the basic model results using the DOE data. This graph shows projected LCOE at all possible capacity factors (also referred to as capacity utilization). This figure allows one to compare generating technologies at comparable capacity factors (i.e., nuclear vs. gas CCs at 80% capacity factors) as well as technologies operating at different capacity factors (i.e., coal at 85% with solar thermal at 25%). The same data is available in tabular form by pressing the **Table** hyperlink (Figure A2). The table includes arrows indicating historical capacity factors for each technology, as reported by the Department of Energy (EIA 2005a). The table displays LCOE in 5% increments up to 100% capacity utilization for illustrative purposes.

The base case results using each data set are summarized in Table A3. These results suggest that, at historical capacity factors, and in the absence of externality costs and renewable tax credits, pulverized coal and nuclear plants are the least cost alternatives at 4.5 and

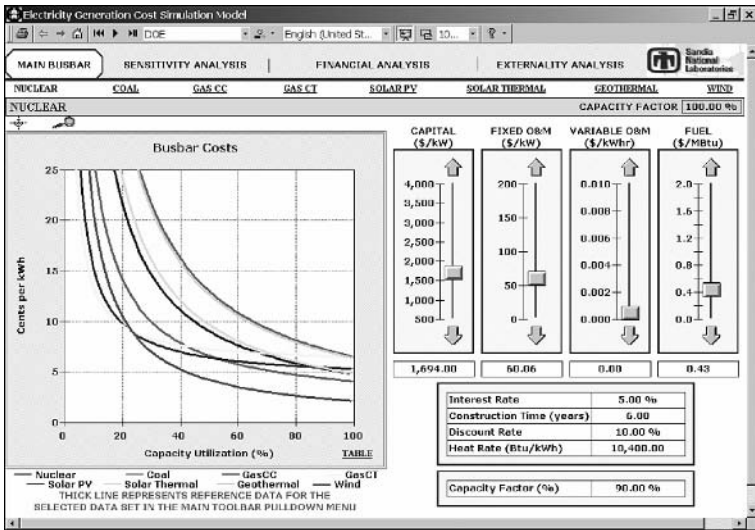


Figure A1. Representative GenSim main busbar screen (nuclear) showing busbar production costs for all possible capacity factors.

BUSBAR COSTS (cents/kWh)								FACILITY ACTUAL CAPACITY FACTOR
CF	NUCLEAR	COAL	GASCC	GASCT	SOLAR PV	SOLAR THERMAL	GEOTHERMAL	WIND
5	84.74	51.03	26.47	21.11	120.87	56.47	126.55	41.05
10	42.67	26.74	15.32	13.42	64.94	48.23	63.27	23.97
15	28.64	18.34	11.60	10.85	43.20	32.16	42.18	13.98
20	21.63	14.14	9.75	9.57	32.47	24.12	31.64	13.45
25	17.42	11.62	8.63	8.80	25.97	19.29	25.31	9.39
30	14.61	9.94	7.89	8.26	21.65	16.09	21.09	6.90
35	12.61	8.74	7.36	7.92	18.55	13.79	18.09	5.99
40	11.11	7.84	6.96	7.64	16.23	12.06	15.82	5.24
45	9.94	7.14	6.65	7.43	14.43	10.72	14.06	4.66
50	9.00	6.59	6.40	7.26	12.99	9.65	12.65	4.19
55	8.24	6.13	6.20	7.12	11.81	8.77	11.50	3.81
60	7.50	5.75	6.03	7.00	10.82	8.04	10.55	3.50
65	7.06	5.42	5.89	6.90	9.95	7.42	9.73	3.23
70	6.50	5.15	5.77	6.82	9.28	6.89	9.04	3.00
75	6.20	4.91	5.66	6.74	8.66	6.43	8.44	2.80
80	5.95	4.70	5.57	6.66	8.12	6.03	7.91	2.62
85	5.54	4.51	5.49	6.62	7.64	5.67	7.44	2.47
90	5.26	4.35	5.41	6.57	7.22	5.36	7.03	2.33
95	5.02	4.20	5.35	6.53	6.84	5.08	6.66	2.21
100	4.30	4.07	5.29	6.49	6.49	4.82	6.33	2.10

Figure A2. Tabular results for DOE data (arrows indicate historical capacity factors for each technology).

5.3 cents/kWh, respectively. The results also indicate some fundamental differences in the two data sets. Platt’s assumes that any new gas CT facilities will serve solely as peaking units, with capacity factors around 10%, whereas historical data (EIA 2005a) indicate an average capacity factor close to 30% for these plants.

Table A3. Comparison of base case results using DOE and Platt's data (2003 \$)

	DOE (\$/kWh)	Platt's (\$/kWh)
Nuclear	0.053	–
Coal	0.045	0.046
Gas CC	0.055	0.042
Gas CT	0.082	0.123
Solar PV	0.260	0.723
Solar thermal	0.142	0.243
Geothermal	0.073	–
Wind	0.054	0.068

The largest difference in the base case results is for the case of solar photovoltaic. Estimated costs using DOE and Platt's data are 26 and 72 cents/kWh, respectively. This major difference is due to the assumed capital costs: 3868 \$/kW for the DOE data, compared to 7185 \$/kW for the Platt's data.

In the current version of GenSim, the variable and fixed O&M estimates are based on the default capacity factors in Table A1, as O&M data for other capacity factors were not available. These O&M estimates may not be valid at different rates of capacity utilization. The actual O&M costs for gas CT facilities might be quite different operating at 50 or 60% capacity utilization on a sustained basis, rather than at 30%.

For example, using default O&M assumptions for the range of possible capacity factors for gas CT facilities would appear to indicate that they still can be competitive with gas CC plants at higher capacity factors. However, because the O&M costs are based on estimated capacity factors of just 30% in the DOE data, this conclusion is not valid.

### Sensitivity Analysis

GenSim's structure makes sensitivity analysis easy. A representative screen (solar PV) is shown in Figure A3. This screen allows the user to compare LCOE costs at either comparable capacity factors (i.e., all at 50%), or at default or user defined capacity factors (i.e., solar PV at 20% with nuclear at 90%). LCOE estimates are displayed at the top of the graph. These estimates change as the user changes key assumptions using either the sliders or number boxes on the bottom half of the screen. For example, changing the assumed capital costs for solar PV from 3868 to 1500 \$/kW reduces the LCOE from 26.0 to 10.4 cents/kWh.

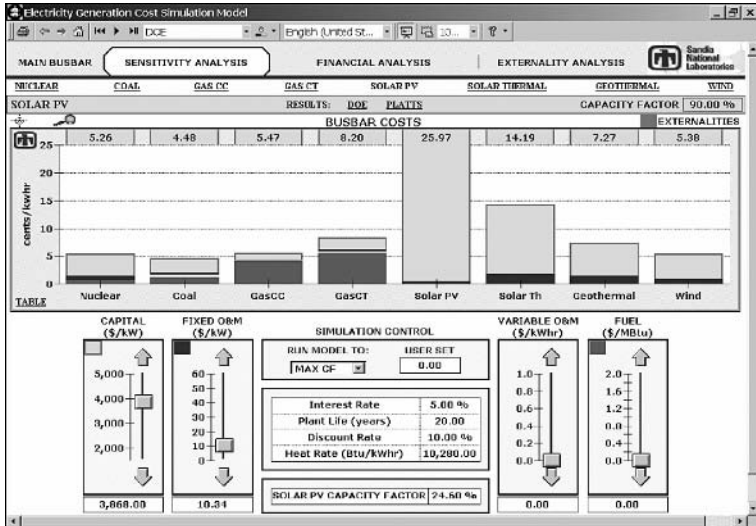


Figure A3. Representative sensitivity analysis screen (solar PV).

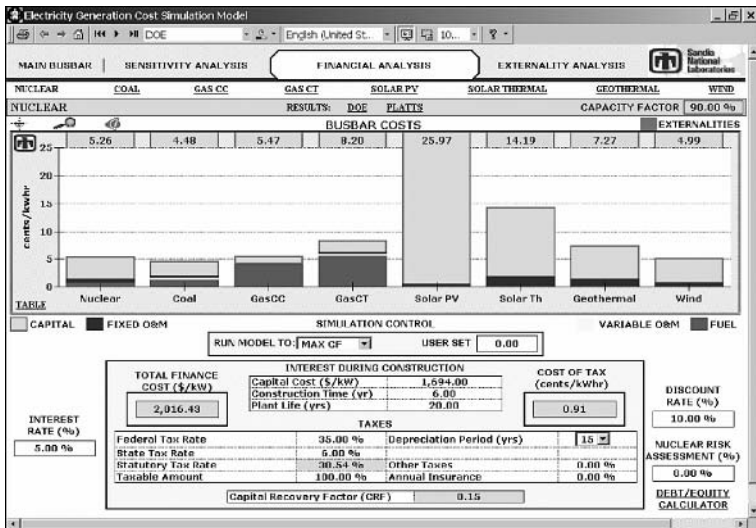


Figure A4. Sensitivity analysis screen for construction time and financing.

Another key assumption driving LCOE estimates is construction time, financing rates, taxes, and depreciation (Figure A4). As with the other screens, the graph on the top is dynamic and changes as the user varies capital costs, tax and financing rates, or construction times. For example, the default setting for nuclear plant construction time is 5 years. By increasing construction time from 6 to 9 years, the LCOE rises from 5.26 to 5.58 cents/kWh. This difference is due to the effects on financing as the total financed costs increased from 2016 to 2179 \$/kW. If delays in construction lead to an extended construction period of 12 years, LCOE costs increase to 5.93 cents/kWh, assuming a linear borrowing pattern and the default capital costs. Construction time is clearly a key factor in the future financial success of nuclear power.

The sensitivity screens are also ideal for answering “what if?” questions. For example, using the default DOE assumptions, advanced coal plants have an economic advantage over gas CC plants at historical capacity factors (4.48 vs. 5.47 cents/kWh). A typical type of “what if” question might be: At what real natural gas price over the life of the plant does the gas option become cheaper? The answer, using the sensitivity screen, is that the break-even natural gas price is 4.45 \$/MBtu, which is 1.47 \$/MBtu lower than the default assumption. This has important implications given the volatility in natural gas prices. Using the same process, the break-even natural gas price at which gas becomes competitive with nuclear is 5.61 \$/MBtu.

The following three sections provide a more detailed sensitivity analysis, derived from GenSim. In the first section, production costs for various technologies are plotted against specific fuel prices. This type of analysis is useful for determining fuel price break-even costs, such as the coal price at which nuclear is cost competitive. The next section determines capital cost break-even points, such as at what capital costs nuclear becomes competitive with coal, gas, or wind. The third section discusses the results of a sensitivity analysis for nuclear plant construction time. All examples use the DOE’s data set; comparable analysis using the Platt’s data set is included in Appendix A.1.

### **Fuel Price Sensitivity Results**

Figure A5 illustrates a real dollar, life-of-plant, break-even analysis for coal, nuclear, and wind technologies compared with natural gas prices. The break-even natural gas fuel price with coal, nuclear, and wind are (in \$/MBtu) 4.45, 5.61, and 5.78, respectively. For comparison, the assumed DOE natural gas fuel price is 5.92 \$/MBtu. Given the relative

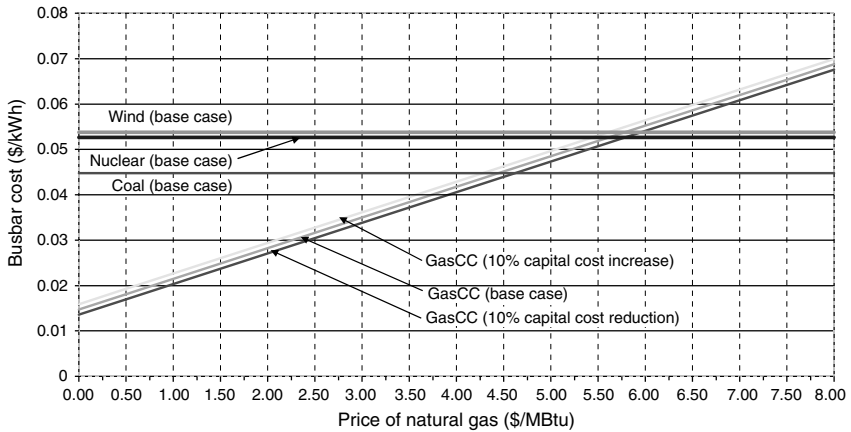


Figure A5. Natural gas fuel price sensitivity analysis.

volatility of natural gas prices<sup>6</sup> compared to coal prices, this result suggests that while LCOE for natural gas plants is higher, the results are highly dependent on fuel prices. Compared to fuel prices, Figure A5 shows that the results are not particularly sensitive to natural gas capital costs. A 10% shift in capital cost in either direction changes these results by only 0.11 \$/MBtu.

Figure A6 illustrates a similar analysis for advanced coal technology. This analysis shows that fuel prices of (in \$/MBtu) 2.18, 2.13, and 2.41, respectively, make coal competitive with nuclear, wind, and gas CC technologies. The default DOE coal price in GenSim is 1.29 \$/MBtu. As with the previous example, these results indicate that coal's competitiveness is very dependent on assumed fuel prices. These results are not very sensitive to changes in capital costs; a 10% difference in capital costs changes these results by 0.26 \$/MBtu.

Figure A7 illustrates the results of the nuclear fuel price sensitivity analysis. This analysis shows that nuclear is competitive with wind, gas CC, and higher priced technologies, such as solar thermal, solar PV, and geothermal (not shown). There is no nuclear fuel price for which nuclear becomes the low-cost alternative. This result reflects the low total fuel cost for nuclear power relative to capital and O&M costs. The break-even nuclear fuel price with gas CC technologies is 0.63 \$/MBtu. For comparison, the DOE default fuel price assumption

<sup>6</sup>The delivered costs of natural gas to electric utility plants averaged 3.57 \$/MBtu, 5.37 \$/MBtu, and 5.90 \$/MBtu in 2002, 2003, and 2004, respectively. For the same years (2002-2000), coal prices averaged: 1.25 \$/MBtu, 1.28 \$/MBtu, and 1.36 \$/MBtu (DOE, 2005b).

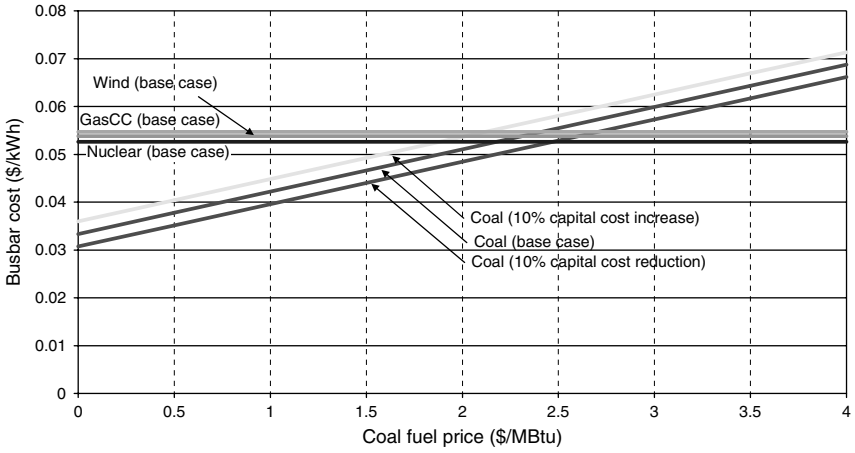


Figure A6. Coal fuel price sensitivity analysis.

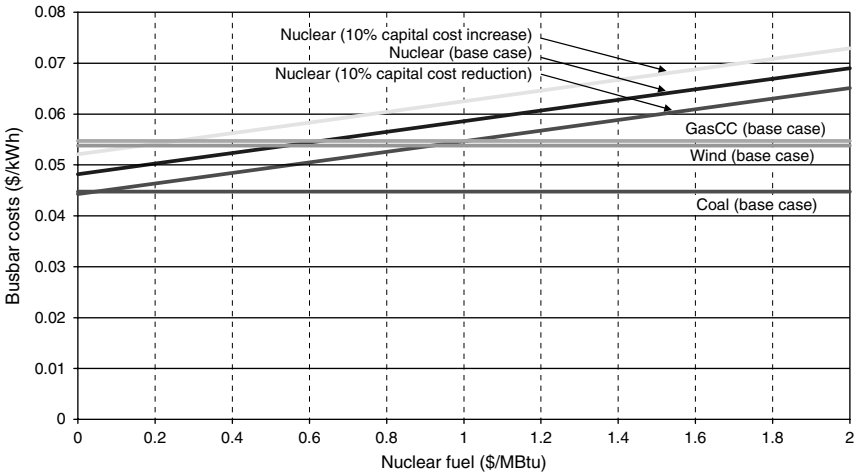


Figure A7. Nuclear fuel price sensitivity analysis.

is 0.43 \$/MBtu. A 10% difference in nuclear capital costs changes these results by 0.39 \$/MBtu.

**Capital Cost Sensitivity Analysis**

Figures A8–A12 illustrate break-even points based on varying capital costs. Figure A8 shows the results for gas CC plants. The default DOE gas CC capital cost is 517 \$/kW. The capital cost at which gas CC technologies become cheaper than nuclear and wind is 425 and

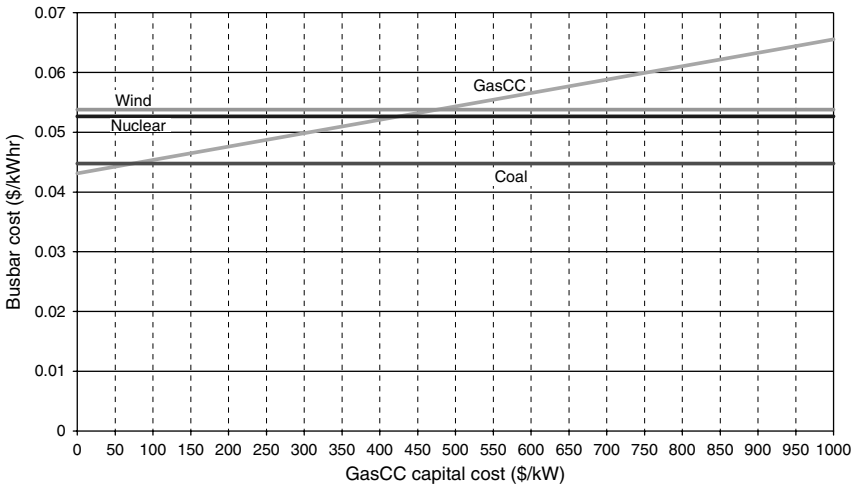


Figure A8. Gas combined cycle capital cost sensitivity.

475 \$/kW, respectively. Gas CC plants are competitive with solar and geothermal technologies for gas CC capital costs below 1325 \$/kW.

Advanced coal generating facilities are cost competitive with gas, solar, geothermal, and wind at any coal capital cost below 1527 \$/kW (Figure A9). The point at which nuclear facilities become cost competitive is at 1480 \$/kW. The default DOE capital cost assumption for advanced coal facilities is 1134 \$/kW.

The nuclear option becomes cost competitive with coal generating technologies at 1355 \$/kW (Figure A10). The default DOE capital cost assumption for nuclear is 1694 \$/kW.

Grid-connected wind-generated electricity becomes cost competitive with coal and nuclear at wind capital costs of 850 and 1034 \$/kW, respectively (Figure A.11). For comparison, the default DOE wind capital cost assumption is 1060 \$/kW. Figure A11 also illustrates the impact on wind economics of a 1.8 cent per kWh production tax credit (PTC).<sup>7</sup> This PTC greatly improves the economic feasibility of wind systems.<sup>8</sup> The wind capital cost at which coal technology becomes competitive

<sup>7</sup> The Energy Policy Act of 1992 established a 1.5 cent per kWh production tax credit (PTC) for wind-powered electricity, adjusted annually for inflation. This amounts to 1.8 cents per kWh in 2005.

<sup>8</sup> According to the American Wind Energy Association, an estimated 2,000–2,500 MW of new wind capacity will be constructed in 2005; the previous record was in 2001 when 1696 MW of new wind capacity was added. New capacity dropped significantly in 2002 due to uncertainty in extension of the PTC (AWEA 2005).

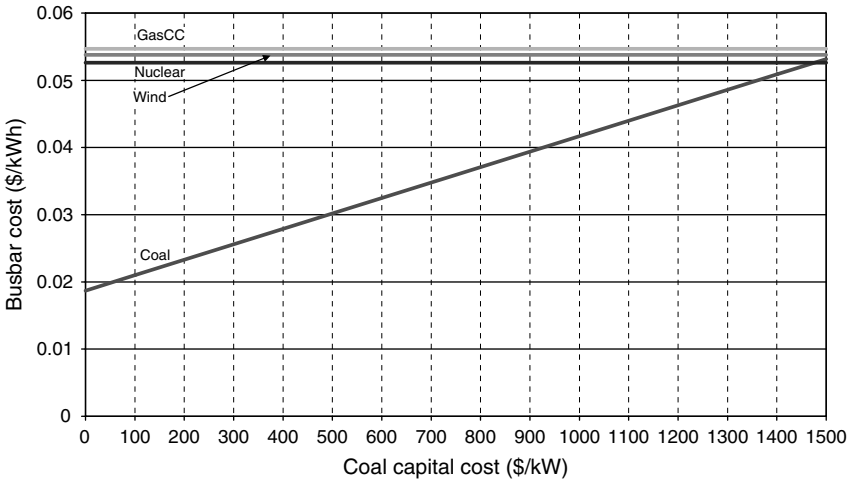


Figure A9. Advanced coal capital cost sensitivity.

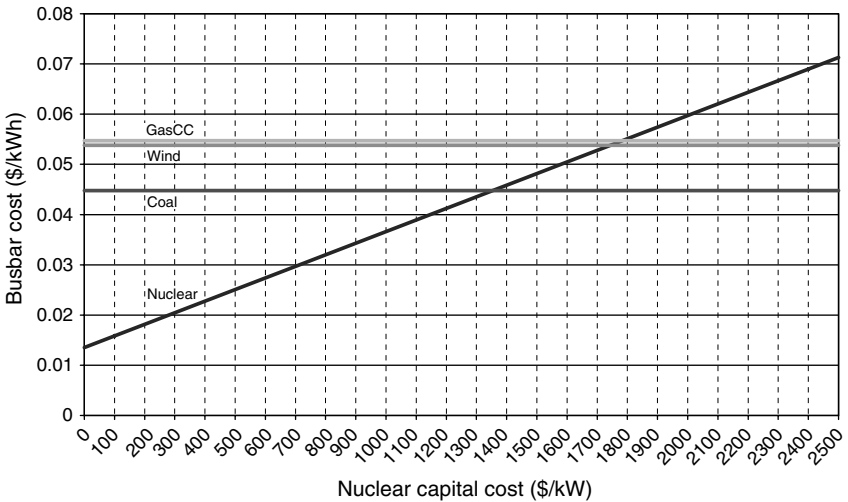


Figure A10. Nuclear capital cost sensitivity analysis.

increases to 1270 and 1450 \$/kW, respectively. This is comparable to reducing wind's capital costs by 415 \$/kW.

**Construction Time Sensitivity**

Figure A12 illustrates the overall sensitivity of nuclear economics to construction time. These results assume constant capital expenditures

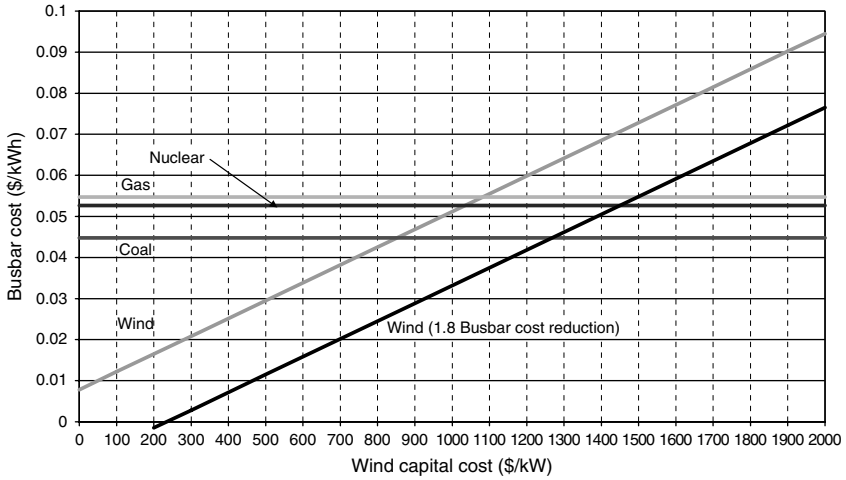


Figure A11. Wind capital cost sensitivity analysis.

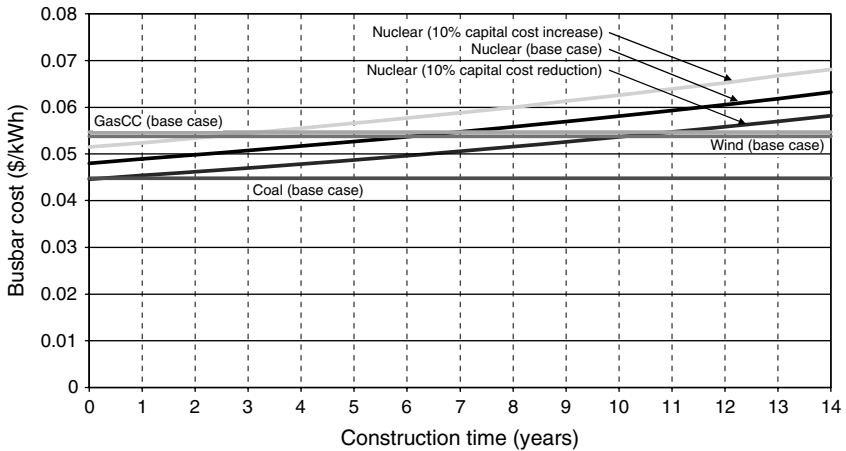


Figure A12. Nuclear construction time sensitivity analysis.

over the life of the project. Even considering construction time, with or without a 10% decrease in capital cost expenditures, it is unlikely nuclear can compete with coal facilities. Nuclear capital cost expenditures would have to decrease by 10% and plant construction time would have to be 1 year for nuclear to become competitive with coal generating facilities. Nuclear plant construction must be delayed beyond 2 years over the default 6-year construction time for gas CC technology

to become cost competitive with nuclear. Raising nuclear capital cost by 10% and delaying construction by more than 15 years would be required to make solar (PV and thermal) and geothermal technology cost competitive with nuclear.

### Externality Analysis

GenSim includes an extensive externality component that allows the user to consider the costs of externalities on LCOE estimates. Initially, GenSim assumes that the prices for all four externalities, CO<sub>2</sub>, NO<sub>x</sub>, SO<sub>2</sub>, and mercury (Hg) are set at zero. The capital costs for each generating option include those associated with the best available control technologies for both SO<sub>2</sub> and NO<sub>x</sub>. CO<sub>2</sub> and mercury emission technology costs are not included in the default capital costs. Using this externality component, the user can explore the effect of externality costs and/or different pollution-control technologies on the estimates of LCOE.

Figure A13 shows the externality cost overview screen. From this screen, the user can explore the effects of pollution taxes for the default pollution-control technologies (Table A4). Additional options, including technology choices for pollution reduction, are accessed by clicking one

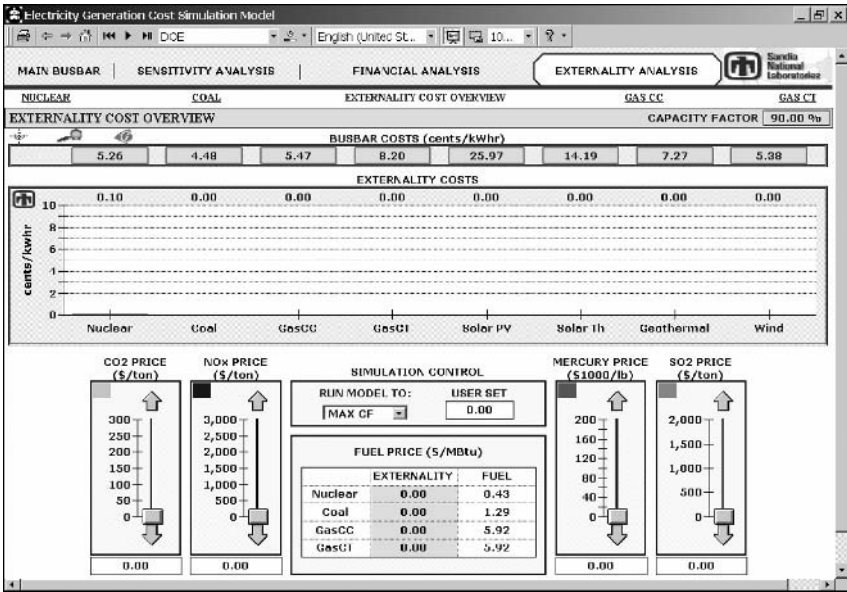


Figure A13. Main externality analysis screen.

Table A4. Default pollution control technology assumptions

Plant type	Pollutant	Default technology	% of pollutant removed
Coal	SO <sub>2</sub>	Limestone forced oxidation (LSFO)	95
	NO <sub>x</sub>	Low NO <sub>x</sub> burner with overfire air (LNB with OFA) and selective catalytic reduction (SCR)	95
Gas CC	NO <sub>x</sub>	Selective catalytic reduction (SCR)	80
Gas CT	NO <sub>x</sub>	Selective catalytic reduction (SCR)	80

of the choices beneath the main toolbar. These options are summarized in Appendix A.2.

As an example, Figure A14 illustrates the potential impact of including externality costs for CO<sub>2</sub>, SO<sub>2</sub>, and NO<sub>x</sub>. Both SO<sub>2</sub> and NO<sub>x</sub> are currently regulated under the Clean Air Act, which requires emission allowances for these pollutants. CO<sub>2</sub> and mercury emissions are not currently regulated, although proposals are pending.

This example assumes CO<sub>2</sub> prices of 100 \$/ton, SO<sub>2</sub> prices of 150 \$/ton, and NO<sub>x</sub> prices of 1500 \$/ton. This increases the estimated LCOE of coal from 4.48 to 6.80 cents/kWh. The estimates for gas CC increase from 5.47 to 6.50 cents/kWh. This increased cost for coal and gas CC is

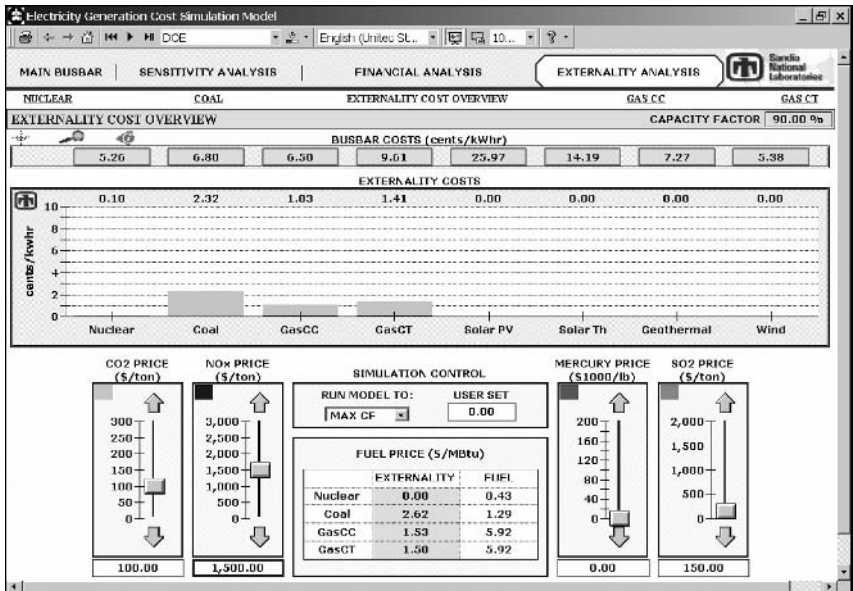


Figure A14. Three pollutant externality example.

equivalent to increased fuel costs of 2.62 and 1.53 \$/MBtu, respectively, also shown in Figure A14. Coal is affected more than gas since natural gas does not contain sulfur and releases less CO<sub>2</sub> per unit of energy consumed.

Consider the effect of just CO<sub>2</sub>. A 100 \$/ton tax on carbon emissions would increase electricity production costs from coal by 2.27 cents/kWh, from 4.48 to 6.75 cents/kWh. For a gas CC plant, LCOE costs increase by 0.95 cents/kWh, from 5.47 to 6.42 cents/kWh. The relatively small change over the three-pollutant example reflects the assumption that each new plant already includes SO<sub>2</sub> and NO<sub>x</sub> pollution-control technologies.

For the nuclear option, the externality analysis is limited to consideration of dealing with the spent fuel. Currently, US reactors are charged a flat fee of 1 mill (one tenth of a cent) per kWh produced electricity. This charge is expected to cover the cost of the eventual entombment of this material in a central location such as at Yucca Mountain, Nevada. GenSim allows the user to explore the impact of changing this assumption about spent fuel storage costs. Other externalities could be added as well through increased storage costs. The base case assumes a 1 mill/kWh charge.

GenSim also permits the user to consider the overall costs of pollution control. Without pollution-control technologies included in the analysis, LCOE estimates for coal and natural gas decrease 0.70 and 0.06 cents/kWh, respectively. These are the implied costs of the required pollution-control devices.

In addition to the type of externality analysis illustrated here, GenSim allows users to conduct a wide range of more detailed externality analyses. The various options by technology and pollutant are summarized in Appendix A.2.

## Conclusions

The Electricity Generation Cost Simulation Model (GenSim) is a user-friendly, high-level dynamic simulation model that calculates electricity production costs over a wide range of facility and economic assumptions including capital, O&M, and fuel costs, construction times, taxes, depreciation, and interest and discount rates. These electrical production costs are calculated for a variety of electricity generation technologies, including: pulverized coal, gas CT, gas CC, nuclear, solar (PV and thermal), geothermal, and wind.

The model permits a wide range of sensitivity and externality analyses. Its ease of use and intuitive, graphical display will give policy makers, energy executives, and their staffs a better understanding of the economic viability of generating technologies and their emissions trade-offs.

**A.1 Sensitivity Analysis using Platt’s Data**

This appendix replicates the sensitivity analysis contained in the main section of this report using the Platt’s data. Nuclear-related analysis is not possible as the Platt’s data does not include nuclear data (Figures A15–A19).

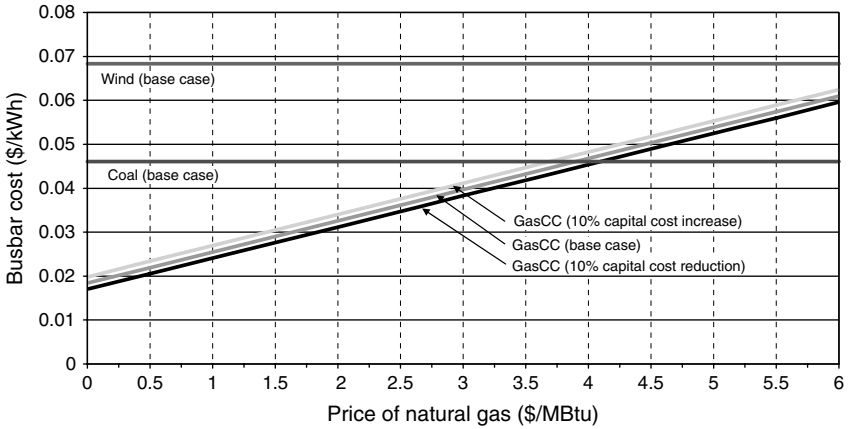


Figure A15. Sensitivity analysis for natural gas fuel prices using Platt’s data.

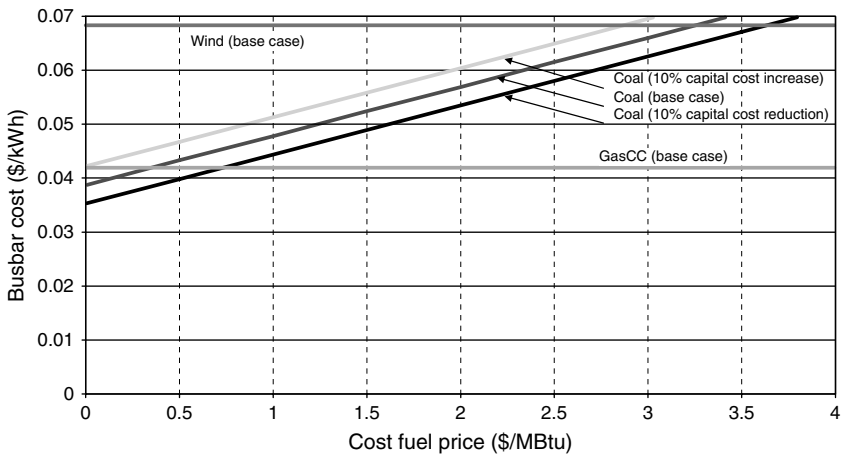


Figure A16. Sensitivity analysis for coal fuel prices using Platt’s data.

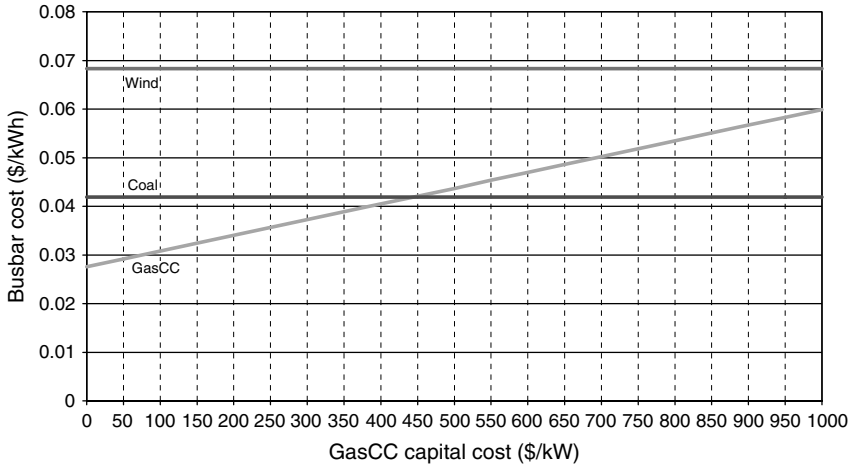


Figure A17. Sensitivity analysis of gas CC capital costs using Platt's data.

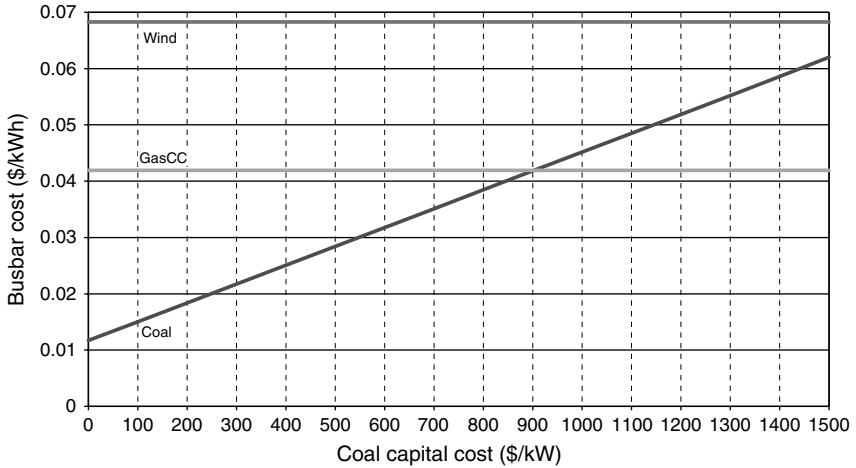


Figure A18. Sensitivity analysis on coal capital costs using Platt's data.

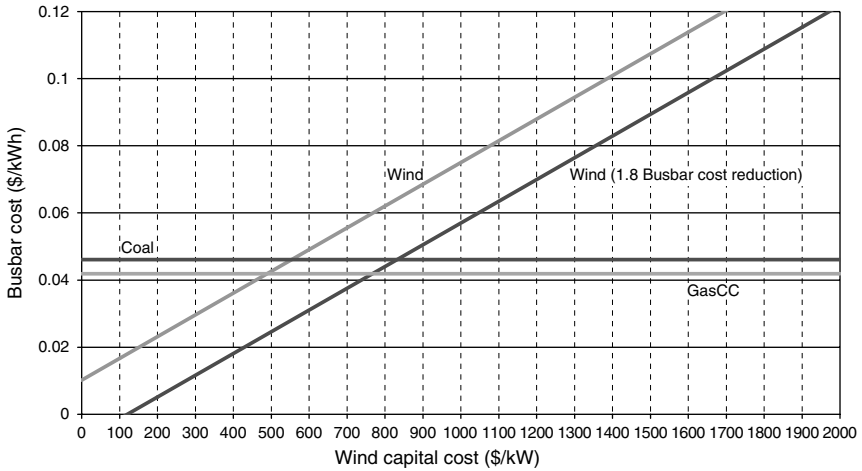


Figure A19. Sensitivity analysis on wind capital costs using Platt’s data.

### A.2 Detailed Externality Assumptions Available in GenSim

Table A5. SO<sub>2</sub> removal options from coal-fired plants and resulting emissions

Technology	Pollutant removed (%)	Pollutant remaining (lbs/MBtu)
Limestone forced oxidation	95	0.18
Magnesium enhanced lime slurry	96	0.15
Lime spray drying	90	0.36
No controls	0	3.64

Assumes 2% sulfur content and coal heat content of 11 000 Btu/lb. User may change these assumptions.

Table A6. NO<sub>x</sub>-removal technology options for coal-fired plants and resultant pollution reduction and remaining emissions

Boiler	Technology	Pollutant removed (%)	Pollutant remaining (lbs/MBtu)
Dry bottom wall fired	<i>Low NO<sub>x</sub> burner, w/o overfired air and:</i>		
	Selective catalytic reduction	96	0.05
	Non-selected catalytic reduction	76	0.19
	Natural gas reburn	81	0.15
	No post combustion control	63	0.30

Table A6. NO<sub>x</sub>-removal technology options for coal-fired plants and resultant pollution reduction and remaining emissions *continued*

Boiler	Technology	Pollutant removed (%)	Pollutant remaining (lbs/MBtu)
	<i>Low NO<sub>x</sub> burner, with overfired air and:</i>		
	Selective catalytic reduction	95	0.05
	Non-selected catalytic reduction	67	0.26
	Natural gas reburn	75	0.20
	No post combustion control	50	0.40
Tangentially fired	<i>LNC1</i>		
	Selective catalytic reduction	95	0.05
	Non-selected catalytic reduction	66	0.27
	Natural Gas Reburn	74	0.21
	No post combustion control	47	0.42
	<i>LNC2</i>		
	Selective catalytic reduction	95	0.05
	Non-selected catalytic reduction	69	0.25
	Natural gas reburn	76	0.19
	No post combustion control	52	0.38
	<i>LNC3</i>		
	Selective catalytic reduction	96	0.05
	Non-selected catalytic reduction	72	0.22
	Natural gas reburn	79	0.17
	No post combustion control	57	0.34
Cell burner	Selective catalytic reduction	96	0.05
	Non-selected catalytic reduction	74	0.21
	Natural gas reburn	80	0.16
	No post combustion control	60	0.32
Cyclone	Selective catalytic reduction	95	0.05
	Non-selected catalytic reduction	68	0.26
	Natural gas reburn	75	0.20
	No post combustion control	50	0.40
Wet bottom	Selective catalytic reduction	95	0.05
	Non-selected catalytic reduction	68	0.26
	Natural gas reburn	75	0.20
	No post combustion control	50	0.40
Vertically fired	Selective catalytic reduction	94	0.05
	Non-selected catalytic reduction	61	0.31
	Natural gas reburn	70	0.24
	No post combustion control	40	0.48

Table A7. NO<sub>x</sub> removal technologies for gas combined cycle and gas combustion turbine facilities

Technology	Pollutant removed (%)	Pollutant remaining (lbs/MBtu)
Selective catalytic reduction	80	0.16
Non-selected catalytic reduction	50	0.40
No Controls	0	0.80

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