U.S. Energy Scenarios

for the 21st Century:

Appendix B: Technology Assessments

Prepared for the Pew Center on Global Climate Change

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Appendix B. Technology Assessments

Several technologies, currently in various stages of development, have the potential to radically transform future U.S. energy supply and demand. The following assessments offer an overview of six categories of these technologies: geological carbon sequestration, fuel cells, hydrogen, energy efficiency, advanced nuclear generation, and distributed generation. The technologies are assessed in terms of their technical characteristics, environmental attributes, energy security implications, expected timing and availability, costs, key uncertainties, and issues affecting deployment. The role of the technologies in the Pew Center scenarios is also discussed.

Carbon Capture, Separation, and Storage in Geological Formations[22]

Concerns about the effects of greenhouse gas (GHG) buildup in the atmosphere have triggered a major research effort to develop cost-effective processes for removing carbon, as carbon dioxide (CO_2), from fossil fuels, either before or after the fuel is burned, and storing the CO_2 in ways that will not result in significant subsequent releases into the atmosphere. The following sections highlight the technological potential and challenges of these technologies and some key issues affecting their deployment during the next thirty years.

Characteristics of Carbon Capture, Separation, and Storage Technologies

Researchers are investigating a number of options for carbon capture, separation, and storage in geological formations. Relevant technologies are currently used primarily for large volume separation of CO_2 in gas and oil production, for injection of CO_2 to enhance oil and gas recovery, in commercial fertilizer manufacturing processes, and in petrochemical refining. Achieving widespread commercial application of capture and separation of CO_2 from electricity generating stations and its subsequent storage in geologic formations will require additional research into the fate of injected CO_2 as well as the development of new technologies and the adaptation and integration of technologies presently used for other purposes. If technology development is successful, integration proves practical, and underground storage proves to be environmentally sound, continued use of fossil fuels without negative GHG consequences may be feasible.

Options for CO_2 Capture and Separation

Before CO_2 can be stored in geological formations, it must be separated and captured, either from a raw fuel resource, from a manufacturing process, or from the flue-gas streams arising from fossil fuel combustion processes. Currently available options for CO_2 separation and capture are shown in Table 1 below.

Table 1. Options for CO₂ separation and capture

| Option	Present Use	Constraints to Wider Applications
Chemical or physical absorption	Gas streams with high CO_2 concentration	Low CO_2 concentrations in post-combustion flue gases makes separation costly. Sensitivity of separation technologies to contaminants in post-combustion gases entails significant replacement and maintenance. Gas streams with low CO_2 concentration result in high energy penalties.
Chemical or physical adsorption	CO_2 removal from petrochemical exhaust gases	High costs High energy requirements
Low temperature distillation	High purity CO_2 streams	Large energy requirements for chilling gases Need to remove impurities
Gas separation via membranes	Gas streams with high CO_2 concentrations	High cost of inorganic membranes
Pre-combustion decarbonization	Primarily used in production of ammonia-based fertilizers	Lack of experience with processes and technologies Higher technological performance risk

Options for Carbon Storage

The principal options for CO_2 storage (also referred to as sequestration) in geologic formations include:

- Injection into salt domes or depleted oil and gas fields;
- Injection into unmineable coal seams; and
- Storage in deep brine-filled reservoirs.

Among the candidate reservoir formations, land-based, deep brine-filled reservoirs are far more extensive and widely distributed in the United States than oil and gas fields, or unmineable coal seams. Brine-filled reservoirs that are 800 or more meters below ground level are likely to be more suitable for storing carbon than brine-filled reservoirs at lesser depths. The light blue dotted areas in Figure 1 represent some of the regions in which brine-filled reservoirs are found below a depth of 800 meters in the United States.

Figure 1
Location of Representative Deep Brine-Filled Reservoirs in the United States
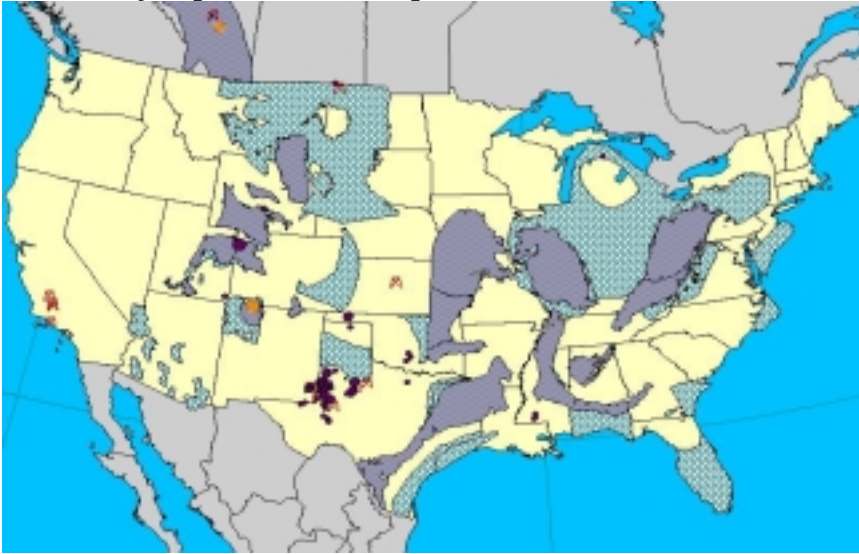
Source: RT Dahowski and JJ Dooley, 2003.

Table 2 below summarizes the present status and estimated capacity of the principal geologic storage options.

Table 2. Options for geologic storage of CO_2

Storage Option	Present Status	Constraints on Use for CO_2 Storage	Estimated Potential Capacity
Oil and Gas Fields	Used for enhanced oil and gas recovery U.S.: Current storage rate is approximately 8 MMTC/yr	Low cost of natural CO_2 compared to CO_2 from power generators Location of fields relative to sources of waste CO_2	U.S. total: 30 GtC Global: 200-500 GtC
Unmineable Coal Beds	Used for coal-bed methane recovery Pilot test in the San Juan Basin	Need to improve understanding of effects of injecting CO_2 into such reservoirs	U.S. total: 9.5 GtC. Global: 100-300GtC
Brine-filled Reservoirs	Statoil's Sleipner T project in Norway: 0.3 MMTC/yr Proposed AEP project in US Proposed BP project in En Salah Frio Pilot Test in Texas	Need to improve understanding of effects of injecting CO_2 into such reservoirs	U.S. total: 500 GtC. Global total: 100s to 1,000s of GtC, possibly more.

Note: Total U.S. GHG emissions in 2000 were 1.9 Gigatons of carbon equivalent (GtC).
1 MMTC = One million metric tons carbon = 10^{-3} GtC

Sources:
Bruant, et al, 2002
Herzog, et al., 1997
Parson and Keith,1998
Simbeck, 2002a
Stevens, 2002
http://www.fossil.energy.gov/coal_power/sequestration/

Environmental Implications of Carbon Sequestration in Geological Formations

Proponents of carbon sequestration technology argue that geologic storage capacity may be sufficiently large to allow continued use of coal and other fossil fuels. If proven safe and cost-effective, geologic storage could allow continued use of fossil fuel resources with attendant economic benefits and minimal environmental risk. From a GHG perspective, the principal concern related to carbon sequestration and geologic storage is the risk that injected CO2 will slowly leak back into the atmosphere.

To be successful in reducing buildup of CO_2 in the atmosphere, the CO_2 must continue to be isolated from the atmosphere for periods ranging from centuries to millennia.[23] A number of biogeophysical processes or conditions can affect rates of leakage from geological storage sites back to the atmosphere. These processes are neither completely understood nor proven in the context of CO_2 sequestration. Research is now underway to gain a better understanding of target geological formations and the fate of CO_2 injected into them.

Because injection of CO_2 may increase gas pressure throughout an entire reservoir, pressurization may increase the risk of a CO_2 leakage or "breakthrough." Although considered low-probability events, if breakthroughs resulted in intrusion into groundwater reservoirs they could result in contamination of drinking water. Rapid venting to the surface, also considered a low probability event, could pose risks of damage to flora and fauna, including suffocation if local conditions to caused the CO_2 to pool in one place, rather than to disperse. Thus, use of geological formations for CO_2 storage will require careful assessment and characterization of both the geologic structure of candidate reservoirs and of suggested pipeline routes.

Major uncertainties that will affect the maximum feasible potential of this technology include the likely rates of leakage for CO_2 injected in various geological formations and the question of whether storage sites must be limited to reservoirs with impermeable caps (particularly in the case of deep brine-filled reservoirs). Additional pilot and demonstration projects operating over a period of years are needed to determine with confidence whether this technology can successfully store CO_2 over relevant time periods and whether it would result in undesirable environmental impacts, including impacts on reservoir ecosystems. Resolving these issues is likely to require on-site monitoring and performance evaluation for a period of years to decades.

Expected Availability

In some situations it is already cost-effective to capture and inject waste CO_2. Adding CO_2 removal and sequestration systems to conventional coal-fired power plants, however, can result in cost increases of up to 75 percent, and efficiency penalties of about 30 percent. Developing technically and economically feasible methods to significantly reduce CO_2 emissions from fossil-fuel electricity generating plants may require the development of new technologies and the integration of technologies that are currently used for other purposes.

Injection in Depleted Oil and Gas Wells

Injection of CO_2 to enhance recovery of oil and gas from depleted wells is currently cost-effective in some locations. Most existing enhanced oil recovery (EOR) projects use natural rather than waste CO_2 as it is usually less expensive. Long-term storage is not, however, an objective in existing EOR applications, and the first major field experiments to monitor the fate of injected CO_2 are now underway.

There are currently 74 active CO_2 EOR projects in the United States. In 2000, U.S. EOR projects produced an estimated 216,00 barrels of oil per day (approximately 4 percent of U.S. production) and are thought to have stored nearly 0.03 gigatons (Gt) of CO_2 annually (8 MMtC) (Stevens et al., 2000). The injection rate of 8 MMtC per year for EOR in the United State is roughly equivalent to the typical output of four 1,000 MWe coal-fired power plants or 44 hours of aggregate U.S. emissions at current emissions rates. Estimates suggest that active U.S. gas fields could store up to approximately 0.3 Gt of C per year without exceeding original reservoir pressure (Baes, et al., 1980). This

estimated annual uptake capacity can be compared to total U.S. CO_2 emissions from electricity generation in 2000 of approximately 0.64 Gt of C. Injection of waste CO_2 in conjunction with EOR is likely to be the first avenue explored by facilities attempting to integrate geological storage with large CO_2 waste streams, due to the revenue associated with EOR. Nonetheless, the future role of EOR in sequestering waste CO_2 from U.S. power plants may be limited, partly due to the distances of oil and gas fields from most electricity generating facilities.

Injection in Coal Beds

Recent estimates indicate that close to 10 Gt of C (approximately six times annual U.S. emissions in 2002) could be stored in U.S. coal formations. However, considerable research is required to determine the fate and long-term viability of CO_2 disposal in deep coal formations.

Deep Brine-filled Reservoirs

Brine-filled reservoirs represent the largest and most geographically dispersed of the potential geologic CO_2 disposal sites. Estimates of the potential global carbon storage capacity in brine-filled reservoirs run from the hundreds to thousands of Gt of C. Recent research suggests that ultimate capacity may be an order of magnitude greater (Herzog, et al., 1997; Bruant, et al., 2002). If secure storage of CO_2 in deep brine-filled reservoirs does not require impermeable caps, capacity should be sufficient to store CO_2 emissions for the foreseeable future. However, a number of reservoir characteristics—including reservoir geochemistry, porosity, and permeability—in addition to cap rock characteristics influence storage capacity and risk of leakage. Until the effects of these characteristics on capacity and leakage are better known, the reservoir capacity suitable for long-term CO_2 storage cannot be estimated with certainty.

Current and Expected Costs

The future costs of CO_2 capture and storage are also uncertain. Benson (2001) suggests using current disposal costs for liquid industrial wastes in deep geologic formations as a rough analogue, although future CO_2 storage costs may be somewhat less. She notes that disposal costs for industrial liquids are in the range of $49 to $207 per ton. These could be significantly higher than costs for CO_2 storage because of the hazardous nature of these liquids and the economies of scale that could arise in CO_2 storage projects. Simbeck (2002b) suggests that in new power plants with CO_2 controls, approximately 50 percent of CO_2 control costs represent the cost of capturing the CO_2, 25 percent of the costs go to compression of the gas after capture, and 25 percent of the total cost covers the expected costs of disposal and sequestration. The future costs of monitoring and of verification for carbon sequestration projects is also unknown.

Table 3 summarizes estimates of the costs of generating electricity from fossil fuels with and without carbon capture for a number of technological options. Assumptions about the degree to which existing plants are amortized, the cost of capital, the future price of natural gas and coal, and whether there is a charge for disposal of CO_2 or a credit for CO_2 reductions can affect the relative costs of each approach.

Table 3: Estimates of Electricity Cost Using Selected Technologies, with and without Carbon Capture

Coal Technology	Cost without carbon capture (cents/kWh)	Cost with carbon capture (cents/kWh)	Difference (cents/kWh)	Percentage Increase
PC today[1]	4.39	7.71	3.32	*76%*
PC 2012[1]	4.10	6.26	2.16	*53%*
IGCC today[1]	4.99	6.69	1.70	*34%*
IGCC 2012[1]	4.10	5.14	1.04	*25%*
PC[2]	3.23	*5.17*	*1.94*	60%
IGCC[2]	3.12-3.55			
IGCC[3]	3.75	5.42	*1.67*	*44%*
PC[4]	1.21			
PC with O_2 firing[4]		3.60	*2.39*	*197%*
PC with amine scrubber[4]		3.98	*2.77*	*228%*
PC with 65% CO_2 reduction [4]		3.42	*2.21*	*182%*
IGCC[4]		3.42	*2.21*	*182%*

Notes:

Costs with superscript #4 are for fully amortized plants.

PC = pulverized coal; IGCC = integrated gasification combined cycle

Numbers in italics in the columns labeled "Difference" or "Percentage Increase" have been calculated based on other information provided in the source documents.

[1] Table 2, David, J. and H. Herzog.

[2] Table 8.4, UNDP, 2000.

[3] Table 5, Williams, Robert, April 2001.

[4] Table 1, Simbeck, Dale, 2001a.

When natural gas prices are low, the most cost-effective option will likely be the construction of a natural gas combined-cycle plant, with flue gas scrubbing of CO_2 using amine solutions. If natural gas prices are high, the preferred option for CO_2 control will probably involve continued use of coal. As indicated in Table 3, if CO_2 capture is required, recent studies suggest that conversion to coal gasification technologies with pre-combustion capture of CO_2 is likely to be more economically attractive than post-combustion capture of CO_2 in flue gases emitted by a pulverized coal-burning boiler. However, the capital-intensive nature of conversion to gasification makes the cost of capital a critical determinant of overall project economics. The greater technological risks of this approach also act to retard adoption of gasification.

Other Issues Affecting Deployment of Carbon Sequestration Technology

A number of issues will affect the rate of commercial deployment of carbon sequestration technology. Some of these issues are reviewed below.

Energy Security Implications

Carbon capture, separation, and storage technologies could have positive implications for energy security, if these technologies can be safely and cost-effectively implemented in the United States. Because the United States has such large coal reserves, extensive use of carbon capture and sequestration technology could allow coal and other domestic fossil fuel resources to satisfy a variety of U.S. energy needs without significantly increasing U.S. CO_2 emissions. Cost-effective carbon capture, sequestration, and storage open up an important potential pathway to production of hydrogen (H_2) from domestically available fossil fuels. The availability of large volumes of domestically produced H_2 could encourage widespread use of hydrogen as an energy carrier for production of electricity, heat, and transportation fuels. Widespread use of hydrogen would also enhance the commercialization potential of fuel cells. If a substantial fraction of consumer demand for energy in the transportation sector could be shifted to hydrogen, the United States might be able to supply most of its remaining oil demand from domestic and North American sources.

Infrastructure Issues

Depleted oil and gas reservoirs are presently considered the most promising early candidates for carbon sequestration because significantly more is known about the characteristics of the reservoirs and because revenue streams may be associated with their use. However, in many cases such sites are not located near large CO_2 emissions sources. Transporting CO_2 from emission sites to these storage locations could raise the cost of this technology. Since pipelines for transporting CO_2 from power generation facilities to oil and gas reservoirs are not currently in place, new pipelines would have to be constructed, potentially slowing deployment. In addition, the limited capacity of oil and gas wells imposes a natural size cap on the potential for their use in storing CO_2, highlighting the question of whether the much larger potential capacity of saline aquifers can be safely utilized. Co-location may be less of an issue for such reservoirs, but current understanding of their suitability is more limited.

Institutional Issues

The key institutional issues for this technology are development of standards for long-term disposal facilities and pipeline routing. In particular, Benson (2001) identifies management issues related to regulatory oversight, site characterization, project monitoring, and performance confirmation. These issues include the absence of an accepted institutional model for long-term waste management; the requirements for monitoring; the need for risk assessment and management; and mitigation and corrective action strategies. Benson (2001) argues that U.S. experiences with storage of natural gas

and liquid chemical and radioactive wastes could be used to provide guidance for addressing these management issues. Table 4 summarizes the U.S. experience with underground storage.

Table 4. U.S. experience with underground storage

Material stored and amount (U.S.)	Regulatory approach	Record	Considerations for CO_2 storage
Natural gas 139 MMT	No Harmful Migration	Very good, but with a few early failures associated with leakage up abandoned wells or poor characterization of the caprock	Good analogue for CO_2 storage
Liquid chemicals; 9 billion gallons annually	No Migration	Some failures early in the program Current regulations are effective in preventing groundwater contamination	Initial regulations not strict enough: 1. poor site characterization 2. improper well completion 3. inadequate monitoring 4. leakage after abandonment
Radioactive materials	Multi-barrier containment systems that limit exposures to safe levels over 10,000 years	Waste Isolation Pilot Project permitted and in operation Yucca Mountain site selected for license application	Site-specific operational requirements Monitoring linked to performance Uncertainty explicitly addressed

The type of regulatory paradigm that is applied to CO_2 storage sites will have an important impact on the cost of operating these facilities and on the extent of public confidence in their operation. If the sites are not carefully regulated and frequently or continuously monitored, the public will have limited confidence in their safety. However, if each site requires an individually designed monitoring plan, and a program of continuous monitoring for a period of decades, the cost of disposal may become a significant barrier to widespread use of carbon sequestration technology. Clearly, if this technology is to be widely used, a successful regulatory framework will need to consider both costs and risks.

Social acceptance issues

The social acceptance of carbon sequestration in geological formations will rest on public perception of the need to address climate change and on weighing the benefits and risks of this technology compared to other options for addressing climate change. Although most scientists believe that this technology poses no special or extreme risks, either in routine operations or during possible accident sequences, public acceptance of this technology is far from assured. Benson (2001) observes that the best way to ensure public acceptance of carbon sequestration in geologic formations is to involve all key stakeholders, including the members of affected communities. Only if local communities are engaged early and actively are technology developers likely to persuade affected communities to accept this technology.

Technological and Cost Issues

Table 5 below compares storage options in terms of four key parameters:
- capacity
- cost to develop and utilize
- integrity
- technical feasibility

Table 5: Comparison of Principal Sequestration Options

Storage Type	Relative Capacity	Relative Cost	Storage Integrity	Technical Feasibility
Coal Beds	Unknown	Low	Unknown	Unknown
Depleted Oil and Gas Fields	Moderate	Low	Unknown	High
Deep Brine-filled Reservoirs	Large	Unknown	Unknown	Unknown
Mined Caverns and Salt Domes	Large	Very High	Good	High

The Role of Carbon Capture, Separation, and Storage in the Pew Center Scenarios

The maximum estimated storage requirement in 2035 for any of the Pew Center scenarios is approximately 0.26 Gt of C per year. Since it is estimated that currently active oil and gas wells could sequester 0.3 GtC per year, it is unlikely that reservoir capacity will become a binding constraint on carbon sequestration in any of these scenarios. However, given that carbon storage in U.S. geologic formations currently is less than 0.0005 Gt of C, expanding the technology to the level suggested by the *Turbulent World with Policy* scenario (i.e., 0.26 Gt per year in 2035) represents more than a 500-fold increase above current levels. The rate of capacity expansion needed to achieve this would present a huge challenge.

The Pew Center scenarios incorporate estimates of carbon sequestration costs that are in the middle of the published ranges. Since many of the component elements of this technology are already in use, it is reasonable to think that future costs will be similar to, or less than, current costs.

Conclusions

Technologies for CO_2 capture, separation, and injection in geologic formations are currently available and in limited commercial use. Most current injection practices do not have permanent storage as a goal, and questions remain as to the fate of the injected CO_2. The scale of operation for these technologies in current applications is several orders of magnitude smaller than would be needed to play a significant role in limiting U.S. carbon emissions. In addition, the capture and separation technologies currently in use are not cost-effective for removing CO_2 from the flue gas stream of existing power plants. Many challenges associated with scale-up and integration of advanced carbon capture, separation, and sequestration technologies remain to be addressed and resolved.

A number of experts believe that the most promising option for carbon sequestration involves coal-based, pre-combustion capture and separation with subsequent geologic storage of CO_2. The best economics arise when this technology is combined with centralized production of hydrogen for use as a fuel. All of the components of this technology are in use for other purposes today but no one has demonstrated a full-scale integrated system of this type. Full-scale demonstrations and several years of continuous operation are needed to determine whether this technology will be safe and cost-effective. A substantial investment in research and development as well as a major policy commitment to this technology will be necessary to bring it to market in the foreseeable future. If these commitments are made during the next decade, carbon capture and sequestration technology could make an important contribution to GHG emission control strategies in the United States during the next thirty years.

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Fuel Cells

Fuel cells are electrochemical devices that combine hydrogen and oxygen in the presence of a conducting electrolyte to generate electricity, water, and heat. Stationary fuel cells can generate electricity and heat for industrial processes, and mobile fuel cells can be used to power vehicles.

Commercial sales of fuel cells are already underway, although global production remains relatively small. Worldwide fuel cell capacity was approximately 45 megawatts-electric (MWe) in 2002 (ABI, 2002). The largest demand has historically been for stationary fuel cells in units of several hundred kW that are used in commercial buildings applications. However, in November 2002, Honda and Toyota began to lease fleets of fuel cell powered vehicles to government agencies in Japan and California. Eight major automakers have announced initial production and planned marketing of early fuel cell vehicles by 2005.

The current market for fuel cell power systems is limited by the fact that fuel cells cost approximately 7 to 10 times as much as combined-cycle gas turbines, per MWe of generating capacity. Nonetheless, a recent survey of global market potential for fuel cell power systems indicates that fuel cell electric generating capacity could reach 16,000 MWe by 2012 (ABI, 2002). This market penetration is based on cost and performance improvement through continuing R&D, and most importantly through achieving economies of scale in manufacturing and learning-by-doing as fuel cells diffuse into the market.

The following sections highlight the technical, institutional, and environmental challenges facing fuel cell technologies and then assess some of the key issues affecting their cost and deployment during the next thirty years.

Technical Characteristics of Fuel Cell Technologies

All fuel cells share the same basic components. These components are illustrated schematically in Figure 1 below, although details of the chemical reactions used to generate electricity vary among alternative fuel cell designs.

In general, hydrogen enters with the fuel at the anode (negative or "fuel" electrode) of the fuel cell while oxygen simultaneously permeates the cathode (positive or "air" electrode). A catalyst at the anode breaks down the incoming hydrogen, separating atoms of hydrogen into positively charged protons and negatively charged electrons. In the case of an anion transfer fuel cell, the protons (hydrogen ions) pass into the electrolyte and drift toward the cathode. Electrons at the anode are prohibited from entering the electrolyte and are forced to escape into an external circuit, generating electricity. Having passed through the external circuit, the electrons return to the cathode, where they combine with hydrogen ions and with oxygen to form water, releasing heat. Water formed at the cathode is exhausted from the cell along with heat that is produced during the chemical reactions. Other fuel cell types have different electrode reactions, but overall, the

electrochemical net reaction is the same. The hydrogen needed by a fuel cell can be delivered to the cell either as pure gaseous H_2, or separated from another fuel, such as methane, in a reformer.

Figure 1
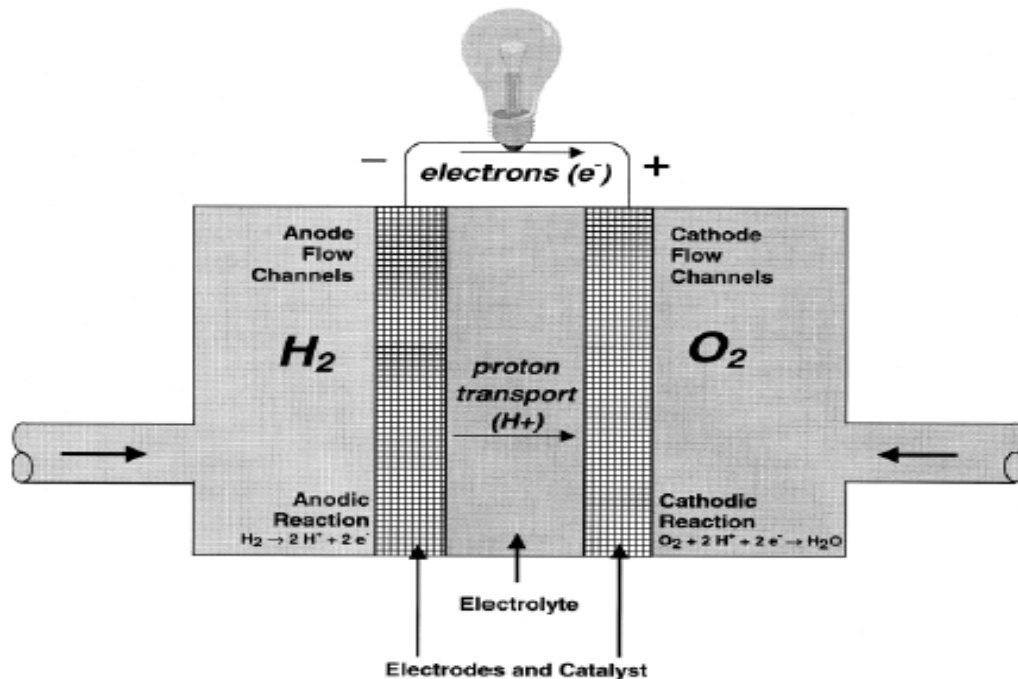
Source: Srinivasan et al., 1999

The Most Promising Options

A number of advanced fuel cell technologies continue to be developed. In principle, fuel cells utilizing hydrogen can operate with fuel-to-electric conversion efficiencies as high as 65 percent on a lower heating value (LHV) basis (Srinivasan, et al., 1999). These efficiencies should be compared to the average fuel-to-electric conversion efficiency of only 32 to 35 percent in conventional coal and nuclear plants. Fuel cells also excel in CHP applications. In CHP applications, some types of fuel cells can convert up to 80 percent (and could be even higher in well-matched applications) of the energy in the fuel to electricity plus heat.

Various approaches to the development of fuel cell technology have been driven by the need to reduce the cost of fuel cell manufacturing and to increase the durability of fuel cell systems during routine operations. Each family of fuel cells uses a unique combination of fuel, catalyst, and electrolyte. The most promising fuel cell technologies include:

- Proton Exchange Membrane fuel cells (PEMFCs);
- Phosphoric Acid Fuel Cells (PAFCs);

- Molten Carbonate Fuel Cells (MCFCs); and
- Solid Oxide Fuel Cells (SOFCs).

Table 1 below displays the key characteristics of some of the most promising emerging fuel cell technologies, and identifies their electrolytes, catalysts, and fuel requirements.

Table 1: Fuel Cell Technology Characteristics

	Proton Exchange Membrane	Phosphoric Acid	Molten Carbonate	*Solid Oxide*
Electrolyte	Polymer	Phosphoric Acid	Molten carbonate salt	Ceramic
Catalyst	Rough-surface carbon paper or cloth embedded with platinum powder	Carbon paper coated with platinum powder	None required (high temp)	None required (high temp)
Operating Temperature	180° F (75° C)	400°F (210° C)	1200° F (650° C)	1500-1800° F (800-1000° C)
Target Efficiency	35-60%	35-50%	40-55%	45-60%
Fuel Requirement	Pure hydrogen; Methanol or natural gas with reformer	Hydrogen, but not as pure as PEM requires; Natural gas with reformer	Natural gas with integrated reformer	Hydrogen or hydrocarbons without reformer
Cogeneration Capability	Hot water	Hot water	Hot water or steam	Hot water or steam
Basic Module Size	3 – 250 kW	40 – 200 kW	250 kW	1 kW – 300 kW
Commercial Status	Likely commercialization in 2003	Some commercially available	Likely commercialization in 2004	Likely commercialization in 2003
Likely Application	Mobile applications; Stationary applications	Stationary applications	Stationary applications	Stationary applications coupled to gas or steam turbines
Challenges	Reducing use of platinum or other rare earth metals as catalyst; Risk for CO poisoning catalyst	Long warm-up time	Managing waste heat and hot electrolyte mixture	Materials compatibility and manufacturing costs

Data from Swisher, 2002 and Srinivasan et al., 1999

Environmental Implications of Fuel Cell Technologies

One of the attractions of fuel cell technology is that its widespread use could significantly reduce emissions of air pollutants in the transportation sector and in electricity

production. Fuel cells significantly reduce local air pollution compared to combustion technologies. They emit no SO_2, and release extremely low levels of NO_x, CO, and PM10. Fuel cells that use pure hydrogen gas emit only water and heat as by-products. Their high efficiencies also mean lower CO_2 emissions on a life-cycle basis, even if the hydrogen is made from fossil fuels. Thomas (2001) concludes that a fuel cell powered car using hydrogen from natural gas would emit 40 to 45 percent less CO_2 than a comparable, gasoline-powered vehicle with an internal combustion engine.

If the hydrogen required to run fuel cells could be cost-effectively produced without burning fossil fuels (and thus releasing CO_2), then these systems might substantially reduce GHG emissions from electric power production. Hydrogen can be produced from oil, coal, or natural gas with no net GHG emissions—if the carbon in these fuels can be captured and securely sequestered (see accompanying technology assessment, "Carbon Capture, Separation, and Storage in Geological Formations"). Coal may become an especially attractive feedstock for U.S. hydrogen production because the United States has a vast supply of low-cost domestic coal.

The only potentially significant negative environmental impacts of fuel cell technology involve the handling and disposal of exotic materials, including catalysts (such as platinum) and electrolytes. Most fuel cell technologies involve use of heavy metals, exotic compounds, or rare earth elements, which are toxic and must be disposed of or recycled carefully. However, these materials present no new or unique disposal requirements compared to many other conventional industrial processes.

Reduction in the amount of such materials required for each fuel cell, or substitution of other, less hazardous materials, may substantially reduce these risks. For example, the amount of platinum used as a catalyst in proton exchange membrane fuel cells (PEMFCs) has decreased from about 28 mg per square centimeter (cm^2) of catalyst to approximately 0.2 mg per cm^2. In addition, fuel cell cars would not require platinum-containing catalytic converters on their exhaust systems (now required for cars and trucks with conventional internal combustion engines burning gasoline). The total amount of platinum now used in light-duty vehicles could actually decline with the transition to fuel cell powered cars and could free up some platinum for other end-use applications.

Energy Security Implications

One aspect of fuel cell technology that adds to its attraction for the United States is its ability to substitute for petroleum products used in transportation. Because the source for hydrogen (e.g., natural gas, coal, or water for electrolysis) can be extracted from North American resources, increased reliance on fuel cells for transportation could significantly reduce U.S. dependence on imported oil. However, at the current rate of turnover of the U.S. vehicle fleet, the process of reducing U.S. oil import dependence will extend over decades.

Although the accelerated commercialization of fuel cell technology for mobile applications may lead to lower levels of U.S. dependence on foreign oil, large-scale

development of stationary fuel cells for electric power applications could increase U.S. demands for natural gas. However, some experts suggest that fuel-cell vehicles using hydrogen derived from natural gas could actually reduce overall U.S. demand for natural gas. They argue that when the vehicles are not being driven and are parked adjacent to buildings, vehicle fuel cells could be used to deliver electricity to meet some of the building's energy demands. Because of the fuel cell's high efficiency, this could be more efficient than supplying electricity from a conventional natural gas power plant and sending the electricity through the transmission and distribution system to the same site.

Configured as a distributed generation technology, the substitution of fuel cells for centralized generation would improve reliability and system performance in the electric power sector (Swisher, 2001). Widespread use of distributed fuel cells could also lower the energy security risks associated with dependence on large, centralized energy production facilities.

Expected Timing and Availability

Each of the fuel cell technologies described above is progressing through research and development. Only one technology (the phosphoric acid fuel cell system produced by UTC Fuel Cells) is commercially available today. These stationary fuel cells are sold today for applications requiring high levels of reliability.

Proton exchange membrane fuel cells (PEMFCs) are expected to enter commercial vehicle markets within a year; both Honda and Toyota began small-volume leasing of fuel-cell vehicles burning hydrogen gas in December 2002. Honda delivered the first of its fuel cell powered *FCX* cars to Mayor Jim Hahn of Los Angeles, CA, on December 2, 2002. The fuel cell power plant in the *FCX* cars can generate up to 80 horsepower and 201 foot-pounds of torque, giving the vehicle an acceleration profile similar to the Honda *Civic* sedan. The *FCX* has a range of 170 miles and seats four adults. It is the first fuel cell vehicle to be certified by both the U.S. Environmental Protection Agency and the California Air Resources Board as a Zero Emissions Vehicle, or ZEV. Honda plans to lease approximately 30 of the vehicles in California and Japan during the next three years.

Toyota delivered its first fuel cell vehicles, one each to the Irvine and Davis campuses of the University of California, in December 2002. Toyota plans over the next year to deliver a total of six vehicles to the campuses of the University of California as part of its efforts to promote "fuel cell communities" around the state. Each fuel cell community will involve a partnership among government, business, and university organizations to address the infrastructure and consumer-acceptance challenges inherent in the process of fuel cell market development. The Toyota FHCV-4 is based on the Highlander, a popular, mid-size, five-passenger sport-utility vehicle. It has strong acceleration and can travel 180 miles before re-fueling.

The current status of fuel cell technologies in the United States is listed in Table 1.

Current and Expected Costs

Fuel cells in the United States are currently too expensive for most applications. The current goal for PEMFCs is approximately $20/kW for the fuel cell stack and $50/kW for an entire vehicle propulsion system. Arthur D. Little (ADL, 2000) recently analyzed the costs of a 50 kW fuel cell system for transportation applications, based on production of 50,000 units per year. Using year 2000 technology, the system analyzed by ADL would cost approximately $177 per kW or $8,850 for the fuel cell alone. The full system, including reformer and other balance-of-system components, was estimated to cost approximately $294/kW or $14,700 per unit. ADL estimated that by 2004, a similar system should cost approximately $50/kW.

Lipman and Sperling (1999) analyzed the expected future costs of fuel cells for mobile applications using a technique based on manufacturing cost functions. They conclude that manufacturing costs as low as approximately $90/kWe are likely to be achieved eventually, for example, when a single manufacturer reaches cumulative production levels of one million MWe.

If hydrogen fuel cell vehicles are designed "from the wheels up" to be powered by fuel cells (rather than as retrofits to existing ICE vehicle designs), substantial cost savings are possible. Lovins (2002) argues that the *Hypercar* (a high-performance, low-drag, high-efficiency, midsize sport-utility vehicle) can be more than adequately powered by a fuel stack rated at only 35 kW. If a vehicle like the *Hypercar* could be brought to market, its systemic cost advantages would support commercial market penetration as a fuel cell vehicle, even at today's fuel cell manufacturing costs. In this configuration, consumers can afford a higher price for the small fuel cell stack because the integrated design creates large savings in both manufacturing and operating costs for the car as a whole.

For stationary applications, the current installed cost for a 200 kW fuel cell (sold by UTC) is approximately $4500 per kWe (UTC, 2003). The current U.S. DOE goals for 2003 are to deliver stationary fuel cell systems at costs of approximately $1500 per kW installed, with efficiencies of 50 to 60 percent. This is considered a critical step on the path to the second-stage U.S. DOE goals for fuel cells, which is to have fuel cells operating at efficiencies of 70 to 80 percent, costing approximately $400/kW in 2015.

The Electric Power Research Institute estimates that the most cost-effective near-term designs may involve hybrid fuel cell configurations that deliver waste heat from the fuel cells into a secondary turbine (EPRI, 2002). EPRI projects that the near-term market for these hybrid fuel cell systems in stationary power applications may be as large as 8 GW, if the cost of the devices can be reduced to approximately $1000 to $1400 per kW of installed capacity.

Issues affecting Deployment of Fuel-Cell Technologies

If fuel cell costs in stationary applications remain four to five times the cost of conventional alternatives, it is unlikely that this technology will achieve substantial market penetration except in niche markets where its significant reliability benefits are highly valued.

In addition to reducing the costs of fuel cell manufacturing and deployment, a related issue concerns the recognition in the market of the systemic benefits of distributed fuel cell installations. Fuel cells can add significant value for an electricity distribution company by improving reliability at the end-user level and by reducing or deferring the need for large capital investments on the distribution side of the system. By providing electricity close to the point of end-use, these distributed fuel cell power plants can also offset the need to expand centralized electricity generation and distribution capacity on an integrated grid system. These benefits are not currently valued explicitly in the U.S. market for electricity. But to the extent that utilities compare alternative investments using area and time sensitive cost analysis, these benefits can be recognized explicitly and could strongly affect future investment decisions. For further discussion of the challenges facing the implementation of distributed generation, see the DG Technology Assessment.

In the past, some analysts believed that the deployment of fuel cells would be limited by the availability of platinum catalysts. Continuing improvements in fuel cell design have reduced the amount of platinum required for each cell. As a consequence, platinum supply is unlikely to constrain future fuel cell development.

Deployment of Fuel Cell Technologies in the Pew Center Scenarios

The Pew Center scenarios use as their starting point estimates of fuel cell technology costs that are based on the published estimates of the U.S. DOE. However, fuel cell costs vary by scenario, according to the extent to which the scenario assumes that public and private investment pays off.

In *Turbulent World*, both with and without policy, the federal government launches a major effort (the "moonshot") to advance fuel cell technology and bring down the costs of fuel cell technologies. These efforts are largely driven by concerns about energy security. The public policy response prompts greater interest and investment on the part of the private sector in all distributed generation technologies, including fuel cells. In *Technology Triumphs,* both with and without policy, private investment, state policy activism, consumer interest, and technological breakthroughs combine to bring down fuel cell costs.

In both the *Turbulent World* and *Technology Triumphs* base case scenarios, substantial efforts are made to implement national interconnection standards and to remove regulatory barriers to distributed generation technologies, including fuel cells. These

efforts help to level the playing field between centralized and distributed generation. They have the effect of increasing economic efficiency in U.S. energy markets.

Conclusions

A variety of advanced fuel cell technologies are in the late stages of research and development and the early stages of commercialization in the United States. The fuel cell technologies that are closest to commercialization are the proton exchange membrane fuel cell and the phosphoric acid fuel cell. These technologies offer significant environmental benefits compared to the fossil-fueled combustion technologies they would replace.

For fuel cell technologies to play a significant role in U.S. energy strategy during the next thirty years will require a rapid ramp-up in their development and commercialization. The cost of accelerated development will be significant. Most of the technical, economic, and institutional challenges associated with accelerated commercialization of fuel cell technologies will require sustained attention as well as public and private investment.

To the extent that fuel cells use direct hydrogen, the United States will have to create or adapt the physical infrastructure and the institutional regime necessary to distribute the hydrogen (see the Hydrogen Technology Assessment). The key challenges to a rapid development of fuel cell technologies include high cost, hydrogen availability, and the need to develop methodology for valuing and crediting the benefits of fuel cell distributed generation on the distribution grid.

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Hydrogen

Hydrogen is the most abundant element in the universe, but little exists as a free gas on Earth. Pure hydrogen (H_2) must be separated from water or hydrocarbons. It can be oxidized like a conventional fuel to release heat, or utilized in a fuel cell to produce heat and electricity. This assessment concerns the potential for widespread use of hydrogen as an energy source (most likely in fuel cells) in the power generation and transportation sectors. It addresses the possible characteristics of hydrogen production, storage, and distribution, as well as the environmental consequences and energy security implications of a large-scale transition to hydrogen. Fuel cells are discussed in detail in a separate assessment.

Technical Characteristics of Hydrogen Infrastructure

Background

Most of the hydrogen currently produced worldwide is used on-site for petroleum refining and in the production of methanol, ammonia, and other chemical applications; roughly 5 percent ("merchant hydrogen") is transported via truck or pipeline. Because the infrastructure for transporting merchant hydrogen is small (an estimated 1 percent of the scale needed to support major energy markets) and geographically sparse, the hydrogen production, storage, and delivery infrastructure of the future is likely to be quite different.

Options for hydrogen production

Hydrogen can be extracted either from hydrocarbons using thermochemical processes, or from water using electrolysis. Currently, most hydrogen in the United States is generated by steam reforming of methane (natural gas or CH_4), which consumes about 5 percent of U.S. natural gas production annually (PCAST, 1997). Steam reforming is a thermochemical process in which methane and steam are reacted to produce H_2 and CO_2.

Thermochemical processes (including gasification or reforming) can also be used to extract hydrogen from hydrocarbons other than natural gas, such as coal, oil, gasoline, and methanol, as well as from biomass. Steam reforming of methane is the most efficient process currently available. Other processes, such as partial oxidation and gasification of hydrocarbons and biomass, could become cost-competitive in the future. The environmental impact of reforming or gasifying hydrocarbons could be mitigated if the CO_2 byproduct were to be captured and sequestered (Williams, 2001).

Another method of producing hydrogen involves water electrolysis. Electrolysis uses electricity to split water into its elemental components, hydrogen and oxygen. The electricity can come from any source, including nuclear power or renewable energy. Depending on electricity costs, electrolysis can be cost-competitive for producing small amounts of pure hydrogen; electrolytic hydrogen remains too expensive for large-scale use today.

Options for hydrogen storage

Large quantities of hydrogen can be stored underground as a compressed gas. Intermediate-scale H_2 storage is possible today in liquid form in containers designed to maintain the liquid at low temperatures. Liquid storage would be favored if modest amounts of hydrogen were to be transported long distances by truck, but liquefaction is costly in terms of both money and energy. For vehicle applications, hydrogen can be stored onboard as a compressed gas in high-pressure cylinders, as a liquid in specially designed containers, or in metal hydride compounds that absorb hydrogen under pressure and release it when heated. Compressed-gas storage is considered the most promising near-term alternative for on-board H_2 storage of (Ogden, 2001).

Options for hydrogen delivery to serve the transportation sector

In a centralized H_2 production system, gaseous hydrogen could be transported long distances by pipeline; gaseous or liquid hydrogen could be transported by truck. In a distributed system, hydrogen would be produced locally and then transported for relatively short distances by truck either as a compressed gas, or, in the future, possibly as a metal hydride. Alternatively, it could be carried as a compressed gas through a local pipeline system. With end-user population densities of less than 300 cars per square mile, on-site production, or delivery of liquid hydrogen in trucks from centralized facilities may offer the most cost-effective options (Ogden, 2001). Royal Dutch Shell has suggested that one possible hydrogen distribution option would be containers ("hydrogen in a box"), which could be sold anywhere—for example, in convenience stores or even vending machines (Shell International, 2001). However, this option may entail fundamental technical breakthroughs—for example, in nanotechnology. Despite its high initial capital cost, the most efficient way to deliver H_2 gas over long distances may be through a network of underground pipelines, similar to those now used for natural gas (Ogden, 2001; Dunn, 2001). It may be possible to use existing natural gas pipeline networks; however, in most cases pipeline modifications or additions of small quantities of gases such as carbon monoxide, sulfur dioxide, or oxygen would be needed (Ogden, 1999).

An alternative approach to using hydrogen as a transportation fuel would be to produce it onboard vehicles by reforming readily available fuels such as gasoline, methanol, or ethanol. While onboard reforming helps overcome short-term distribution difficulties, it increases fuel system complexity, fails to eliminate CO_2 emissions, and is currently handicapped by the long warm-up times of today's reforming equipment, by the need for

large tanks (in the case of methanol), and by high reaction temperatures (in the case of gasoline).

Pathways to a hydrogen infrastructure

While the co-development of the hydrogen infrastructure and hydrogen-powered vehicles will require investment and coordination on the part of the government and the private sector, it is not necessary that a centralized hydrogen production system with an extensive pipeline infrastructure be in place before the hydrogen transportation system can move forward. Several alternative pathways have been proposed by Iceland, the Rocky Mountain Institute (RMI), the California Fuel Cell Partnership, and Toyota.

Iceland, with its population primarily concentrated in one city (Reykjavik) and its scarcity of fossil fuels, is uniquely positioned to make the transition to a hydrogen economy by 2030 to 2050. Iceland's abundant and inexpensive hydroelectric and geothermal energy sources—together with ample storage space—may ease initial infrastructure difficulties. Three fuel cell buses are scheduled to begin operation in mid-2003. If this initial experience proves successful, Reykjavik hopes to replace its entire bus fleet with fuel-cell vehicles. Iceland is also investigating fuel-cell technologies for its fishing vessels. Ultimately, the goal is to introduce fuel cells for use in private transportation.

Researchers at Rocky Mountain Institute have outlined a proposal that depends on two pre-conditions: (1) the existence of advanced, lightweight cars whose efficiency enables them to operate with a relatively low-power, fuel-cell power pack,[24] and (2) the integration of fuel-cell systems in vehicles and buildings (Lovins and Williams, 1999). The strategy calls for implementing fuel-cell cogeneration in buildings first. This can already be cost-competitive in some buildings since the portion of the H_2 energy not used for electricity can provide energy for heating, cooling, and dehumidifying. As fuel-cell costs fall, fuel-cell vehicles would be introduced; these vehicles would utilize the spare off-peak capacity of the H_2 sources that would already exist in the buildings. The vehicles, in turn, could be plugged into the buildings to contribute power when not in use.

According to RMI, as more H_2-fueled cars enter the market place, it becomes cost-effective to produce hydrogen at "gas stations," using the same technologies used to produce hydrogen for the stationary fuel cells. Finally, as hydrogen demand grows, upstream H_2 production becomes cost-effective. This hydrogen could be produced either by reforming of natural gas at the wellhead, possibly in conjunction with CO_2 sequestration, or by electrolysis of water using intermittent renewable sources of electricity. While there is no specific timeline associated with the RMI proposal, it does illustrate how the transportation infrastructure can begin to develop, in association with buildings, prior to the implementation of a universal, centralized production and pipeline system.

The California Fuel Cell Partnership commissioned an evaluation of a hypothetical proposal to create a hydrogen infrastructure for fuel-cell vehicles in California (CAFCP,

2001). The proposal entails a pilot period, during which 1000 fuel cell vehicles would be demonstrated in public and private fleets, probably in two metropolitan areas. This would be followed by a period of market introduction of fuel-cell vehicles into California's three largest metropolitan areas, with sales reaching 40,000 vehicles per year within several years, equivalent to 3 percent of sales in these areas. To reach this goal, the study concluded that fuel-cell cars would need to be very attractive to consumers. Direct-hydrogen as well as on-board reforming of methanol, gasoline, and ethanol fuels were considered.

The initial pilot stage calls for 10 to 20 fueling stations, each serving several nearby fleets. A minimum of 500 refueling stations would be needed by the time 40,000 new vehicles are introduced per year. Reaching the 40,000 per year target within four years of starting the market phase would require construction of an average of 10 fueling stations every month at a cost of $1 million each month. The recent replacements of underground gasoline tanks and fuel vending equipment in California (in response to new state regulations) suggest that this rate is manageable with cooperation from multiple fuel suppliers. Further financial analysis indicates, however, that if market penetration rapidly reaches 80,000 new vehicles per year, new infrastructure development may have difficulty keeping up.

Toyota announced the formation of a public-private partnership in December 2002 to address the "chicken and egg" problem of fuel cell vehicles and fueling infrastructure in two communities in California. Based around the University of California's Davis and Irvine campuses, which are leasing fuel-cell vehicles from Toyota, the two university communities will soon have a network of six refueling stations ready for use. Hydrogen refueling stations have been operating in Japan since February 2002.

Shell's novel "hydrogen in a box" delivery system would obviate the need for a special H_2 distribution infrastructure, yet it remains to be seen whether such a concept is practical.

Environmental Implications of Hydrogen Technologies

Proponents of hydrogen technology argue that development and commercialization of hydrogen as an energy carrier will have substantial positive environmental impacts. Widespread use of H_2 fuel cells to provide heat and electricity could significantly reduce U.S. emissions of criteria air pollutants and CO_2 from both the transportation and electric power sectors. The principal "waste" product from this use of hydrogen is pure water.

However, depending on how the hydrogen is generated, H_2 fuel production could have negative environmental impacts. If bulk hydrogen were produced by electrolysis from water, the only emissions would be those associated with producing the electricity for electrolysis; and if such electricity were generated from nuclear or renewable energy technologies, emissions would be minimal. However, if hydrogen were produced thermochemically from a fossil fuel, or electrolytically using fossil fuel-fired electricity, significant emissions would result, unless combined with capture and sequestration of the

resulting CO_2. If CO_2 is not sequestered, analysis of well-to-wheels emissions (e.g. from fuel extraction through processing and final use as a transportation fuel) indicates that using hydrogen produced from natural gas in a fuel cell vehicle results in higher CO_2 emissions than using gasoline or diesel in a hybrid vehicle. Use of hydrogen from natural gas fares better compared to vehicles other than hybrids. Use of coal as the feedstock for hydrogen would result in higher CO_2 emissions if CO_2 is not sequestered (Greene and Schafer, 2003).

Energy Security Implications

Because the resources from which hydrogen can be produced (e.g., natural gas, coal, biomass, or water for electrolysis) are widely available in the United States, increased reliance on hydrogen as a transportation fuel could significantly reduce U.S. dependence on imported oil. However, if fuel-cell vehicles penetrate the U.S. vehicle fleet only at the rate that conventional cars and trucks are now replaced, the process of reducing U.S. oil import dependence would extend over a number of decades

Expected Timing and Availability

Hydrogen technology is commercially available today in the United States but generally restricted to the oil and chemical industries. Several factors will affect the rate at which hydrogen technologies could penetrate U.S. energy markets. Market penetration will depend on both public policy decisions and private investment decisions concerning the development of H_2 infrastructure for production, distribution, and storage, as well as on the development of end-use markets.

Table 1 below summarizes estimates of the time required to build some of the infrastructure options that could support widespread commercialization of hydrogen as a fuel in the United States.

Table 1: Timing of Alternative Hydrogen Infrastructure Options

Infrastructure Option	Time to Implement
On-board gasoline or methanol reforming	Unknown
Small on-site steam methane reformer	Several months per installation
Large steam-reformer plant	Construction period of 2 to 3 years
Pipeline system	Decades

Current and Expected Costs

The most cost-effective method of H_2 production available in the United States today is steam reforming. According to the Department of Energy, the cost of producing hydrogen in 1995 by steam reforming in large plants was about $1/kg (US DOE, 2002).

When considering costs of hydrogen as a transportation fuel, the critical cost is the cost at point of delivery. Simbeck and Change (2002) and Ogden (1999) considered delivered costs both for central plant production and production at fueling stations. Both analyses considered a variety of feedstocks, including natural gas, coal, and water, and delivery by either truck or pipeline. Both studies point out that H_2 production costs are lowest at centralized plants due to economies of scale and lower feedstock and power prices. However, these cost advantages are balanced by the costs incurred for delivery. In particular, liquefaction can be a significant part of total cost. Both studies concluded that reforming of natural gas either at fueling stations or at central plants with delivery by truck are the most attractive options. Both studies also concluded that production of hydrogen from water via electrolysis at fueling stations was the most expensive option and that even using lowest-cost options, delivered costs for hydrogen are still substantially above delivered costs of gasoline. Simbeck and Chang, using conditions appropriate to the New York/New Jersey region, cite delivered prices from a low of $3.70/kg (hydrogen from reformed natural gas and delivered as a liquid in tanker trucks) to a high of $9.10/kg (hydrogen from electrolysis of water with the hydrogen transported via pipeline). Odgen, using conditions appropriate to Southern California and assuming mass-production of small advanced steam reformers, estimates prices from $1.60/kg to $3.80/kg. C.E. Thomas (2002), also assuming mass production of small-scale steam reformer units, gives prices at fuel distribution stations providing hydrogen sufficient to serve 125 to 1250 fuel-cell vehicles per day (approximately 300 kg to 3000 kg H_2 per day) of approximately $0.90 per gallon of gasoline equivalent (approximately $0.98 per kg of H_2).

Issues Affecting Deployment of Hydrogen

The primary issues that need to be addressed for hydrogen to play a significant role in energy markets are cost, the coordinated development of infrastructure, and end-use markets. Development of fuel cells and the fuel cell market are discussed in the separate Fuel-Cell Technology Assessment. Achieving hydrogen's full potential as a fuel will require:

- Solutions to the distribution dilemmas, such as success in developing on-board reforming technologies, a breakthrough approach such as Shell's "hydrogen in a box," or development of a large-scale pipeline system;
- A long-term commitment to research and development of technologies to reduce H_2 production, transport, storage and end use costs;
- Development and implementation of broadly accepted safety standards for H_2 transport, distribution, storage, and use; and

- A sustained cooperative effort involving government, private industry and other stakeholders to select and implement a viable strategy.

Relevance of Hydrogen to the Pew Center Scenarios

Hydrogen plays minor roles in two of the base case scenarios and major roles in all the policy overlay cases. This reflects the use of different H_2 feedstocks and production technologies in the various cases and the attractiveness of H_2 hydrogen fuel as a means for reducing CO_2 emissions.

In the *Turbulent World* base case, hydrogen succeeds because it can be manufactured from domestic resources, principally coal. In the *Technology Triumphs* base case, hydrogen is produced using a number of technologies that become available in different regions of the United States, including technologies using natural gas (as a feedstock) and renewable electricity (as an energy source for electrolysis). In the *Awash in Oil and Gas* base case, hydrogen does not play an important role. In all of the policy overlay cases, hydrogen becomes a major component of the U.S. energy sector.

Conclusions

Hydrogen production, storage, and distribution technologies are currently in various stages of research and development. Increased use of hydrogen as a fuel offers significant environmental benefits compared to the fossil fuel technologies that would be replaced.

For hydrogen technology to play a significant role in U.S. energy strategy during the next thirty years, a rapid ramp-up in development and commercialization of fuel cells will likely be required. There are major technical, economic, and institutional challenges associated with significantly expanding the role of hydrogen in energy markets. For example, the United States will have to create or adapt the physical infrastructure necessary to distribute and store hydrogen as a fuel. To be successful, the United States will have to devote considerable public and private resources and put in place supportive public policies for a large-scale, long-term coordinated effort to address these challenges.

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Energy Efficiency

Energy conversion processes typically achieve efficiencies that are far below the maximum thermodynamic potential. The technical potential of energy efficiency technologies is indisputable but their economic potential varies. For many energy end-uses, implementing cost-effective efficiency improvements could significantly reduce the amount of coal, oil, gas, or electricity that is required to achieve a given level of energy service or economic benefit. Expanding the use of these technically feasible and cost-effective energy efficiency improvements could simultaneously reduce GHG emissions, lower oil import dependence, and strengthen the U.S. economy.

Characteristics of Energy Efficiency Technologies

Technologies for Improving Fuel Use Efficiency in Transportation

Light-duty vehicles

Light-duty vehicles (cars and light trucks) consumed over 50 percent of the fuel used in the transportation sector in 2000. The fuel economy of light-duty vehicles can be improved by about one-third with existing technology at a reasonable cost in the near term. In the longer term, vehicle fuel economy could more than double from today's level, although some analysts suggest that this might substantially increase vehicle-manufacturing costs. Doubling average fuel economy will depend on technological progress in several key areas. Four technological options stand out among the opportunities for improving the efficiency of light duty vehicles. These include:

- Increased use of light-weight structural materials;
- Expanded use of hybrid gasoline-electric and diesel-electric drivetrains;
- Wider use of advanced internal combustion engines (ICEs), including direct-injection gasoline and diesel engines; and
- Commercial development of fuel cells for mobile applications.

Table 1 below summarizes the principal options for improving light-duty vehicle efficiency.

Table 1: Efficiency-Improving Options for Light Duty Vehicles

Option	Principal Contribution to VehicleEfficiency	Annual Savings for Best Available Option	Expected Availability	Reference
Increased use of plastics, fiber composites, aluminum, and ultralight weight steel	Decreases structural weight	Can reduce vehicle mass up to 60%	Currently available	Ford, 1997 Birch, 1999
Expanded use of hybrid gasoline-electric drivetrains	Runs small gas engine at max efficiency point; converts kinetic energy to electricity through regenerative braking	Improves mpg by 80% above CAFE standard	Currently available 50,000+ cars sold by end of 2002	Toyota, 2002
Advanced ICEs	Improves combustion efficiency	Improves mpg up to 80% above CAFE standard	Currently available in cars and heavy trucks	CEF, 2000a Honda, 2002
Fuel cell vehicles	Uses hydrogen as fuel; and converts H2 to H2O	Potential for achieving 100% increase over CAFE with on-board reforming; 200% increase over CAFE with H2 fuel	Possibly available after 2003	Birch, 1999

Some analysts, including those at Rocky Mountain Institute (2003), argue that by starting with a "clean sheet" design concept, it is possible to combine a variety of measures to improve fuel economy in a high-performance, light-duty vehicle (e.g., light-weighting, low drag coefficient, and an electric drive train built around a fuel cell power plant burning hydrogen gas). Careful combination of these elements has led to a "whole system design" for a mid-size, five- passenger, sport-utility vehicle (SUV) that these analysts believe could achieve 90 miles per gallon of gasoline equivalent at a cost competitive with that of vehicles powered by internal combustion engines.

Heavy-duty vehicles

Heavy-duty vehicles consume approximately 20 percent of the fuel used in the transportation sector. The fuel efficiency of heavy-duty vehicles (i.e., large trucks and buses) could be improved by about 25 percent for long-distance transport and 50 percent for local transport. Diesel peak thermal efficiency for vehicles operating in long-distance traffic could be increased by up to 55 percent using a combination of various engine measures. Advanced designs could reduce aerodynamic drag coefficients for heavy trucks by up to 35 percent (U.S. DOE, 2003a). For heavy-duty vehicles that operate locally, hybrid drive-trains are a promising option; hybrid buses in urban transport have reported fuel economy improvements of up to 70 percent (U.S. DOE, 2003b).

Heavy trucks carry a large and growing share of freight traffic in the United States. Several technological options are available to increase the efficiency of freight movement by truck. Improvements in diesel engine technology could raise truck fuel efficiency by

as much as 50 percent, if current U.S. DOE targets are met (U.S. DOE, 1997). A new system that decouples the diesel engine of a heavy truck from the wheels has been shown to improve fuel economy by 20 to 25 percent, compared to a standard transmission (U.S. DoE, 2003d). In addition, filling the tires of long-haul trucks with nitrogen instead of air would allow them to run cooler and at higher pressures, thus reducing rolling friction and increasing mileage by as much as 10 percent. Measures to limit unnecessary idling in Class 7 and 9 long-haul trucks could reduce fuel use in U.S. surface transportation by up to one percent (U.S. DOE, 2003c).

Aircraft Fuel Economy

Fuel used in air transport represented less than 15 percent of all fuel used in the transportation sector in 2000. A number of technological opportunities exist to increase fuel efficiency in air transportation. The largest contributions are expected to come from improved engines with increased bypass ratios for turbo-fan designs and increased thermodynamic efficiency in pure turbine engines. Replacement of existing engines with the best currently available designs could reduce fuel consumption per seat mile by as much as 25 percent during the same period (CEF, 2000a).

Recent engineering advances in airframe design could lead to an additional 15 percent improvement in efficiency by 2020. Another step in that direction was taken in December 2002, when Alan Mulally, Chief Executive Officer of the Boeing Company announced the company's plan to launch a new, 250-passenger, super-efficient, mid-market commercial aircraft in 2004. The new plane will fly 20 percent faster than Boeing's B-767 jet. It will be very quiet and inexpensive to run, with the range of a B-777. However, it will consume 20 percent less fuel per seat-mile. Boeing targets the new plane at airlines that operate point-to-point (hubless) networks and hopes for a general introduction of the aircraft in 2008 (Boeing, 2002).

Technologies for Improving Energy Efficiency in Buildings

Of approximately 100 Quads of primary energy consumed in the United States in 1990, residential and commercial buildings consumed about 30 percent. Substantial cost-effective opportunities exist for improving energy efficiency in both residential and commercial buildings. Energy efficiency opportunities are available through:

- New technologies and materials for building envelopes (windows, walls, roofs, and foundations);
- New technologies for space heating, ventilation and cooling (HVAC);
- Energy-efficient appliances for water heating, lighting, refrigeration, cooking, cleaning, and office equipment;
- Use of a systems or "whole building" design approach. For example, more costly, efficient components may be justified by enabling the use of smaller HVAC systems; and
- Initial and continuous optimization of building HVAC and other mechanical and electrical systems, including use of advanced automated control systems.

Opportunities for improving the energy efficiency of a building envelope occur either at the time of original construction or at the time of retrofit and replacement of existing components. Building shells last 50 to 100 years. Consequently, while energy savings due to advanced building envelopes can be substantial at the individual building level, at the national level significant reductions in energy use from advances in building envelopes is a long-term strategy. Another long-term possibility for reducing the energy-related GHG emissions from the building sector is for buildings to generate their own energy using "environmentally friendly" technologies. Two promising technologies are fuel cells that run on hydrogen, along with photovoltaics integrated into building envelopes (building integrated photovoltaics, or BIPV).

Shorter-term efficiency gains are possible with equipment, because average lifetimes run from 1 to 20 years. Market penetration rates determine the speed with which energy-efficient technology can contribute to reducing the increase in energy consumption at the national level. Penetration rates are influenced by a number of factors including initial costs, lifetime cost-savings, and information.

Adoption of energy efficiency technologies in the buildings sector is also hampered by a variety of factors:

- Savings from equipment are a very small part of household budgets, particularly in the residential market;
- Lack of information about energy-saving options;
- Fragmentation of the construction industry;
- Building occupant interests do not correlate with or influence builder decisions; and
- Consumer preference for low initial costs over lifetime cost-effectiveness sends a contrary "perverse" signal to equipment suppliers.

The most promising avenues for overcoming these barriers may be:

- Adoption of more stringent appliance standards and building codes;
- Change in engineering and architectural fee structures;
- Provision of financing incentives for energy-efficient buildings; and
- Modernization of the construction industry.

One reason why standards and codes may be critical in the building sectors is that while the savings from any single technology or device may be relatively small, aggregate national level energy savings could be very large. The history of appliance standards for refrigerators suggests that upgrading codes and standards may be an effective way to improve the performance of energy-intensive devices. Conventional residential refrigerators manufactured in the 1970s consumed as much as 1800 kWh per year. As of 2001, the federal minimum standard for an average size refrigerator (a 20 cubic foot unit) is 496 kWh per year. Manufacturers, stimulated by the tightened standards, now offer some similarly sized refrigerators that use less than one-fourth of the federal minimum standard. These efficiency gains have been achieved while prices for refrigerators have

fallen, partly due to a major government-funded research and development effort conducted in partnership with industry. It is expected that the percentage of energy used for residential refrigeration will sharply decline because of technological improvements and the implementation of federal appliance standards.

Other technologies that use significant amounts of energy within the building sector and that could be affected by appliance standards are HVAC systems and lighting. Space heating, ventilation, and cooling consume significant amounts of energy in both residential and commercial buildings, accounting for over 40 percent of primary energy use in residential buildings and close to 25 percent of primary energy use in commercial buildings. Near-term energy efficiency improvements can be achieved through optimization of system performance through continuous monitoring and maintenance and adoption of technologies such as variable speed blowers, improved ducts, heat pumps and heat exchangers, advanced building envelopes, whole systems approaches to building design, and advanced automated sensors and controls.

Lighting is the second largest energy end-use in commercial buildings. In the near term, energy efficiency improvements through lighting upgrades (including replacement of conventional incandescent or halogen lamps with compact fluorescent lighting and upgrading existing fluorescent lighting systems from standard T-12 lamps with magnetic ballast to T-8 lamps with electronic ballasts) can result in energy savings of 75 percent compared to conventional lighting. In many commercial building applications, use of metal halide lamps to replace halogen and other high-intensity lamps can lead to similar savings.

Technologies for Improving Energy Efficiency in Industry

The industrial sector accounts for over one-third of total U.S. energy use. Industrial energy use has remained largely flat over the last 25 years, increasing at an average rate of only 0.14 percent annually. This slow increase reflects a shift away from heavy industry and a decline in energy intensity per unit of economic output (EIA, 2002a). A wide range of opportunities exists for continuing to improve the efficiency of energy use in industry. Many industry leaders are now making a determined effort to raise energy efficiency in the U.S. industrial sector because they recognize that these investments can have a positive impact on the bottom line.

Some energy efficiency measures are applicable across a broad range of industries. These crosscutting measures include eliminating unnecessary uses of compressed air, improving motors and motor drives, producing process heat from waste, and improving operations and maintenance for industrial steam applications. Table 3 below details some of the most promising opportunities for efficiency improvement, the potential energy savings these measures could achieve in aggregate, and typical cost savings at the plant level.

Table 3: Technologies to Improve Energy Efficiency in Many Industries

	Potential Areas for Improvement	Aggregate Potential Energy savings (%)	Typical annual savings Per Plant (2000$)
Compressed Air	Leaks, inappropriate use	20-50%	$50,000 by improving a 200hp unit running 7,000 hrs per annum at an 85% capacity factor
Motors	Use synchronous belt drives, eliminate voltage imbalance	Up to 18%	$78,000 by improving 1,000 motors over a 29 building site
Process Heating	Waste products as fuel, air fuel ratio, air preheating	5-25%	$42,000 by lowering the steam system pressure to reduce the average steam demand by almost 6%
Steam	Leaks, insulation, heat traps, end recovery	Up to 20%	$45,000 by eliminating 2% excess oxygen in a 10 MMBTU/hr furnace

Source: U.S. DOE Office of Industrial Technologies at http://www.oit.doe.gov/bestpractices

In addition to the industrial technologies listed above, current R&D activities in a number of areas could lead to further improvements in industrial energy efficiency. These include sensors, control systems, insulation, and new materials.

Other energy-efficient opportunities are specific to particular industries. Table 4 below highlights some illustrative energy efficiency improvements, identified by sector, and details energy savings. All data is taken from (CEF, 2000c). Each of the energy efficiency measures listed below are expected to have a simple payback of four years or less when retrofit to an existing industrial facility.[25]

Table 4: Technologies to Improve Energy Efficiency in Individual Industries

	Energy efficiency technology	Relative energy savings (%)
Petroleum refining	Advanced oxy-fuel combustion systems	Up to 25%
Chemicals	"Pinch" analytical techniques	Up to 50%
Paper	Impulse drying	Up to 30%
Iron and Steel	Direct smelting / reduction	20 – 30%
Aluminum	Hall-Heroult cell stability	Up to 15%
Glass	Advanced burners	Up to 30%

Technologies for Improving Energy Efficiency in Electricity Supply

Electric generation accounts for nearly 40 percent of primary energy use. Significant opportunities exist today to improve the efficiency of electric generation and distribution. Conventional electric generation occurs in centralized steam turbine power plants at typical conversion efficiency of only 30 to 35 percent (measured on the higher heating

value, or HHV, basis). Nearly two-thirds of the energy in the fuel is lost as heat in the plant's exhaust gases.

Opportunities for efficiency improvement at central power plants include simply refurbishing old plants using their existing technology, re-powering them to use new fuels, or converting simple steam turbines to CHP units. Additional opportunities to improve the overall efficiency of the electricity supply system include the introduction of DG, as well as deployment of improved transmission and distribution (T&D) technologies. Table 5 summarizes some of the major opportunities for efficiency gains in the U.S. electricity sector and estimates the potential efficiency savings (CEF, 2000, Hassol et al, 2002).

Table 5: Efficiency Opportunities in the Electricity Supply Sector

	Opportunity	Barriers	Potential efficiency increase
Plant refurbishment	New control technologies, improved maintenance	May trigger regulatory review	Up to 5%
Repower with other fuels	Coal to natural gas using CCGT	Stranded cost if retirement is premature Gas price volatility	Up to 20%
Combined heat and power or distributed generation	Use of heat at point of electricity demand	Regulatory issues including inter-connection and buyback tariffs and NIMBY concerns	Up to 130%total efficiency (electricity + heat)
T&D improvements	Reduce line losses with advanced control technology	High capital investment	Up to 6%

Under current fuel costs (and typical electric plant capital costs), all options listed in Table 5 (except T&D improvements) are cost effective[26] for new plants constructed in 2003. However, in the case of retrofits or re-powering, the financial costs of stranded assets (i.e., capital stock that is retired before it is fully amortized) must also be factored in and may make the investment in energy efficiency less attractive than a similar investment in new construction.

Benefits of Energy Efficiency Technologies

Energy Security Implications

Investment in energy efficiency measures can enhance energy security by reducing oil import dependence. In the transportation sector, energy efficiency improvements could save as much as 5 Quads per year in oil consumption by 2020. This represents a savings of approximately 2.4 million barrels of oil per day, enough oil to have offset all U.S. daily imports from the Persian Gulf states in 2000.

In the industry and buildings sectors, energy efficiency improvements could save approximately 1.5 Quads per year in natural gas consumption by 2020, which is equivalent to 75 percent of net U.S. natural gas imports in 2000 (CEF, 2000c).

Environmental Implications

The U.S. Department of Energy's *Clean Energy Futures* study (CEF, 2000) suggests that aggressive policies to promote implementation of cost-effective energy efficiency measures could reduce primary energy use in the United States by about 10 percent, if implemented in conjunction with a carbon price of $50 per ton. The study suggests that the same policies would reduce U.S. expenditures on energy by 3 percent (or about 1997$ 600 billion) and U.S. carbon emissions by almost 20 percent (or nearly 1.5 gigatons of carbon), relative to a business-as-usual case. The CEF study suggests that the same policies, if continued until 2020, could reduce U.S. energy use by 20 percent and carbon emissions by about 30 percent, while saving U.S. energy consumers more than $570 billion (in 1997$), relative to a business-as-usual case. Although all these measures involve significant real costs, the CEF study indicates that the potential for cost-effective investment in energy efficiency, in the context of aggressive, market-oriented policies, is very sizeable.

Barriers to Energy Efficiency Technologies

A number of barriers constrain the market for energy efficiency technologies and limit their use even when they represent the most cost-effective alternatives for delivering a particular energy service.

Institutional Issues

The lack of consistent, continuous upgrading of efficiency standards for vehicles, buildings, equipment, and appliances reduces incentives to develop and adopt new technologies. In the construction industry, funding for research and development is also extremely limited due to industry fragmentation and inability to prevent other companies from reaping the benefits of one company's R&D. Moreover, in many cases around the United States, local building and other service codes have not kept up with developments in the field of energy efficiency technologies. In some cases, the introduction of such technology may violate these codes, precluding technologies that are technically feasible and economically cost-competitive from playing a role in the marketplace.

Within the construction industry, laws requiring professionals to adhere to "the norms…and practices of other qualified professionals" hamper the introduction of innovative technologies and approaches. Further, the fee structures for engineers and architects are based on total capital cost, promoting the use of HVAC systems typically oversized by a factor of two or three (CEF, 2000b).

As discussed in more depth in the DG technology assessment, the structure of the U.S. electricity market also imposes significant barriers to energy efficient technologies, such

as CHP. The rules and costs of electric grid interconnection, the still limited availability of net metering, and other barriers slow the adoption of DG and CHP.

Market Barriers

A major impediment to penetration of energy-efficient devices is lack of consumer information. Information on the cost-effectiveness of most products is difficult to obtain, hard to understand, or not available. Vehicle purchasers tend to be unaware of the differential environmental consequences of vehicle choices, and in the buildings sector it is usually impossible to determine the contribution of appliances to electricity bills.

There is also often a separation between those who make investment decisions and those who capture the principal benefits. In the buildings sector, for example, the occupant benefits from energy-efficient technologies. However renters, and in many cases buyers, have little if any influence on investment decisions. Moreover, the investor not only does not capture the benefits from energy efficiency investments, market forces tend to discourage investments that increase initial costs to consumers because lower cost products are more likely to sell, even though such investments would result in lower lifetime costs.

Another barrier is insufficient access to financing at attractive rates. In many parts of the United States, it is now easy to get a mortgage or other long-term loan to finance the purchase of an energy-consuming device (like an efficient furnace or air conditioner). It is often much more difficult to get similar financing for purchase of an energy efficiency-improving technology (e.g., extra thick insulation or super-efficient windows or a fuel-cell power plant). Conventional mortgages and other long-term financing do not recognize the benefits of reduced energy costs. Preferential financing for energy-efficient vehicles, buildings, or major equipment upgrades can spread higher initial costs over time, thus reducing this barrier to adoption.

Costs

In many cases, energy-efficient technologies are already cost-competitive or have payback periods of only a few years. However, experience has shown that consumers tend to focus on initial costs, ignoring longer-term financial benefits, particularly if payback periods exceed 2 to 3 years. Even though widespread adoption would result in potentially large energy savings at a national scale, there is little incentive for individual buyers to purchase energy-efficient products because total savings for an individual are often small. For example, the U.S. Environmental Protection Agency estimates that there are 100 million "exit" signs in U.S. buildings. These signs operate 24 hours per day, 365 days per year, at a national-level cost of approximately $1 billion. Replacing one conventional exit sign with a new high-efficiency, ENERGY STAR-rated light-emitting diode (LED) sign reduces baseload power demand by about 35 Watts and only saves the individual operator approximately $15-$20 per year in electricity costs.

Relevance to the Pew Center Scenarios

The principal issues affecting the application of energy efficiency technologies in the Pew Center scenarios are cost, consumer acceptance, and the need to lower existing barriers to competition and market penetration. The scenarios incorporate estimates of the costs of energy efficiency technologies that are in the middle of the published ranges. Since many of these technologies are already in use, it is reasonable to assume that their future costs will be lower than current costs, declining as the cumulative volume of production increases.

In the base case of *Technology Triumphs*, an array of forces converges to increase the adoption of advanced energy efficiency technologies in the marketplace. In *Turbulent World,* tough CAFE standards pull highly efficient vehicles into the market.

The policy overlay included a set of policies and programs that realigned incentives, disseminated information, reformed distortionary tax and regulatory policies, and provided equal access to capital for energy-using and energy-saving technologies. This suite of policies led to successful commercialization and deployment of energy efficiency improving technologies. When the policy overlay was imposed on the base scenarios, the assumption was that investment in public outreach and awareness programs (including product labeling and voluntary agreements with manufacturers) will lead to significant private investment whenever the energy efficiency option is the most cost-effective alternative for performing a particular service. The policy overlay increased the penetration of energy-efficiency technologies in *Technology Triumphs* and *Turbulent World*, but had little effect on penetration in *Awash in Oil and Gas*.

Conclusions

Many technologies for improving the efficiency of energy use are currently available and in use commercially. The technical potential of these technologies for reducing energy use in current applications is about ten times larger than what would be considered cost-effective today at 2002 energy prices. Many institutional and political challenges associated with expanding the market penetration of these technologies remain to be addressed and resolved.

A number of experts believe that the most promising options for improving energy efficiency, reducing carbon emissions, and enhancing U.S. energy security lie in the transportation sector. Recent engineering advances in vehicles and engines have been used largely to enhance vehicle performance (acceleration and handling) rather than to improve fuel economy.

Many technologies to improve the performance of residential and commercial buildings are now commercially available and cost-effective, but face numerous market barriers that slow their adoption. Public policy reforms will be necessary to put these important technical advances on an equal footing with increased energy supply in the U.S. market. Policy options include a carbon constraint, efficiency standards, favorable financing

terms, tax incentives, upgraded building codes, training programs and information dissemination.

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Advanced Nuclear Technologies

The commercial development of nuclear power in the United States faces serious technical, environmental, and economic challenges. License renewals and power up-rating of existing facilities are expected to ensure the continuing operation of the vast majority of existing nuclear plants. Over the last decade, existing nuclear plants have made enormous gains in availability and capacity utilization. With current capacity factors averaging 90 percent, the United States has in effect added substantial nuclear capacity. Existing plants are continuing to increase their actual output through efficiency improvements and minor modifications. Yet no new power plants using light-water reactors (LWRs) have been ordered in the United States since 1978, and several existing plants may be decommissioned during the next decade.

Restructuring of the electric utility industry presents unique economic challenges for an investor-owned utility or a private enterprise considering construction of a new nuclear power plant. It is generally accepted that conventional LWRs are most competitive economically in large plant sizes (1000+ megawatts-electric, MWe). Except in very select circumstances (for instance, a traditional regulatory environment within parts of the U.S. electricity sector), it isn't financially prudent to build a new 1000 to 1200 MWe plant at historical cost levels of $2 billion dollars or more. In most instances, the time required to recover the capital costs and to begin making a profit on the investment is longer than shareholders or the financial community will accept, given the uncertainty and volatility in today's energy marketplace. The nuclear industry is therefore faced with the challenge of finding a technology to replace conventional fission electric power plants that has a more attractive investment profile—one that is safe, cost-effective, and can achieve a faster return on shareholder investment. The key is finding a technology that can be built at substantially lower costs. The Electric Power Research Institute expects that smaller, modular design systems based on units of 200 to 300 MWe each, will have construction costs of $900 to $1250 per kWe. Other analysts are less optimistic about future costs.

Researchers in the United States and elsewhere are developing a number of new concepts for advanced nuclear technology that attempt to address the risks and minimize the costs associated with conventional light-water reactors. The key goals of new reactor designs are to reduce costs and to reduce the risk of accidents. The key goal of new fuel cycles that reprocess and recycle radioactive waste is to minimize the amount of waste created. However, these new fuel cycles create increased risks of weapons proliferation and may increase risks of diversion of nuclear material by sub-national groups. Other approaches seek to minimize these risks by creating passively cooled, accident- and diversion-resistant reactor designs.

Background

The commercial nuclear power industry in the United States is built around an "open" (or once-through) fuel cycle model, meaning that spent fuel is not reprocessed and reused. The conventional LWRs in the U.S. nuclear industry use low-enriched uranium

fuel and operate at an average thermal-to-electric conversion efficiency of about 32 percent. High-level radioactive material is discarded with the plant's spent-fuel assemblies.

The cost to reprocess high-level radioactive waste in spent fuel has traditionally been viewed in the United States as greater than the cost of storing the spent fuel. Additional concerns about links to weapons proliferation drove regulatory constraints and federal energy policies since the 1970s that have discouraged nuclear fuel reprocessing and recycling.

By contrast, France, Germany, Japan, and several other countries reprocess their spent nuclear fuel and operate closed nuclear fuel cycles. In these closed fuel cycles, spent-fuel bundles are removed from the nuclear reactor and prepared for reprocessing. Remaining uranium, along with the plutonium that formed in the nuclear reactor, is extracted through chemical reprocessing at a special facility. The plutonium (which is very dangerous fissionable material) and unused uranium (which is highly valuable) are re-fabricated into new fuel bundles and re-used in another reactor. Fuel that is recovered through reprocessing can be re-used, improving overall fuel utilization efficiency, and increasing the fraction of potential energy in the fuel that is converted to electricity.

Technical Characteristics of Advanced Nuclear Technologies

The development of some advanced nuclear reactor designs has been guided by the need to limit the risks of accidents or diversion of radioactive material by terrorist groups. Other reactor designs seek to lower the capital cost of nuclear power plants by changing the way that plants are built and capturing economies of scale in the manufacturing and construction of these facilities.

Several concepts of advanced nuclear technology are in various stages of research and development. These include:

- Gas-cooled, pebble bed reactors;
- Water-cooled, supercritical reactors;
- Gas Turbine-Modular Helium Reactor;
- Fast-spectrum reactors;
- Integrated actinide conversion systems; and
- High-temperature reactors.

Gas-cooled, pebble bed reactors

In contrast to the fuel-rod bundles at the core of a conventional LWR, the core of a pebble bed reactor (PBR) contains thousands of small spherical uranium and graphite fuel elements. These "pebbles" enter at the top and fall to the bottom of the reactor over time, releasing neutrons as their uranium centers undergo nuclear fission. The even distribution of uranium throughout the reactor increases efficiency, ensures even irradiation of the

fuel, eliminates "hot spots," and reduces the risk of a Loss of Coolant Accident (LOCA), the most dangerous type of failure for a conventional nuclear reactor. Pebble bed reactors will probably use helium gas (rather than steam) as the working fluid driving the turbine. Early PBRs would most likely be used in open fuel cycles.

Proponents argue that one of the most important advantages of the pebble bed design is that it can be built in small modular units of as little as one hundred megawatts electric (100 MWe), whereas conventional LWRs are generally considered to be uneconomic in sizes with rated capacity of less than 900 MWe. The smaller size and modular character of the PBR is expected to shorten the construction period for new reactors and substantially reduce their capital cost. In addition, proponents claim that the PBR design has inherent safety advantages that reduce or eliminate the need for direct operator intervention to avoid a meltdown of the core during emergency situations.

However, opponents of this technology, including Dr. Edward Teller, have argued that the PBR may face other types of accident risk in the course of routine operations. If the boundary between the helium coolant system in the reactor core and the steam system in the generating unit is breached, steam could enter the reactor core, causing a dangerous and explosive reaction. Part of the construction cost savings that is claimed for PBRs comes from eliminating the containment building surrounding the nuclear reactor. Some analysts argue that PBRs will require containment vessels like those now typically used in commercial LWRs. If containment is required, the capital cost of these machines will increase substantially.

Gas Turbine-Modular Helium Reactor

Gas-cooled reactors have operated successfully in the United Kingdom since the 1960s. A new gas-cooled reactor design, the Gas Turbine-Modular Helium Reactor (GT-MHR), has recently been promoted for its potentially high conversion efficiency. Proponents of the GT-MHR contend that it will convert nuclear heat to electricity with 48 percent efficiency—a 50 percent improvement over current reactor technology. In addition, its size and modular design suggest the possibility of low construction cost, with an acceptable risk profile for deployment in the merchant market.

The GT-MHR couples a meltdown-resistant, gas-cooled, modular helium reactor with a high-efficiency gas turbine in an adjacent vessel. Key design features of the GT-MHR are the use of helium coolant, the graphite moderator, and its unusual, refractory-coated particle fuel. The helium coolant is inert and remains as a gas under all conceivable conditions. The graphite moderator has high strength and unusual stability, while the refractory-coated particle fuel retains fission products even at very high temperatures.

The power conversion system of the GT-MHR contains a gas turbine, an electric generator, and gas compressors on a common, vertically oriented shaft that is supported by magnetic bearings. The reactor and power conversion vessels are located below grade in a concrete silo. They are interconnected and communicate through a set of concentric pipes. The helium coolant is heated in the core by flowing downward through channels in

the reactor's graphite fuel elements. The coolant then flows through the concentric pipes of the cross-vessel to the adjoining power conversion system.

Proponents of this design argue that below-grade placement of the reactor and power conversion system in the GT-MHR significantly increases the inherent resistance of these facilities to any physical damage, either from accidents or from intentional disruption (e.g., by acts of terrorism). Underground placement of the reactor may also increase the degree of protection for surrounding communities, if an accident or unanticipated disruption should take place. The GT-HMR reactor could be used in either an open or closed fuel-cycle configuration.

Water-cooled, Supercritical Reactors

Advanced water-cooled reactors are being developed that are capable of maintaining their coolant fluid at supercritical temperatures,[27] dramatically improving their heat transfer characteristics. When used in single-phase operations, these machines can achieve fuel-to-electricity conversion efficiency of up to 45 percent. Advanced water-cooled systems have a relatively small reactor core, thus reducing construction costs for the reactor pressure vessel. In addition, putting the cooling system and control rods entirely within the reactor pressure vessel helps to lower risks of accidents during routine operations. The first generation of water-cooled, supercritical reactors will probably be used in open fuel cycles. The Nuclear Regulatory Commission has already certified the Westinghouse AP-600 design, and efforts are underway to certify its larger and more cost-effective sibling, the AP-1000 unit.

Fast Spectrum Reactors

Whereas conventional LWRs utilize low-temperature, thermal neutrons to sustain a controlled chain reaction in the core, at least one promising nuclear option is designed around a reactor core that generates high-energy, fast neutrons. These new fast spectrum reactors operate at very high temperatures and use liquid metals (such as liquid sodium) or inert gases (such as helium) as their coolant fluid. Examples of fast spectrum reactors have been built in several countries. To date, their construction has proved to be expensive and their operations problematic.

The most promising fast spectrum reactor concepts are designed to operate at atmospheric pressure and to support passive cooling of the reactor core in the event of a LOCA. Additional advantages claimed for the fast spectrum reactor include (1) the ability to operate as the fulcrum of a closed fuel cycle, and (2) a high resistance to conventional loss-of-coolant accidents. Some analysts argue that the advantages claimed for fast spectrum reactors may simultaneously create new and difficult problems. Closed fuel cycles require plutonium reprocessing, potentially increasing the risks of proliferation and diversion of fissile material. In addition, since these machines rely on prompt rather than delayed neutrons to sustain the chain reaction, they may face substantially greater difficulty in controlling the rate of fission in the reactor core.

Integrated Actinide Conversion System

One advanced nuclear option that has only reached the conceptual design phase is called the Integrated Actinide Conversion System (IACS). IACS is an advanced nuclear technology under development by U.S. DOE and the Advanced Research Projects Agency (DARPA) of the U.S. Department of Defense. IACS is designed from the beginning to be used in a closed fuel cycle with plutonium recycling. This technology would take conventional spent nuclear fuel as input, convert it to a new mixed oxide fuel (MO_x), and use it on-site. Each IACS facility could, in principle, recycle spent fuel from five to ten conventional power reactors. By locating the fuel recycling and power production facilities together, this technology minimizes the dangerous transport of plutonium and other high-level radioactive wastes. The remaining IACS waste products that require final disposal are dramatically reduced in volume (as compared to the facility's spent fuel input) and are nearly plutonium-free.

The principal drawback of IACS technology is its high anticipated cost. Construction and operation of the on-site MO_x fabrication facility could further increase fuel costs by as much as 10 percent. In addition, operations and maintenance (O&M) costs for IACS sites are estimated to be up to twice as high per unit of delivered energy than the O&M costs for a conventional LWR. Some analysts argue that it will be quite a long time before this technology could become economically viable (Moniz, 2003).

Environmental Implications of Advanced Nuclear Technologies

The largest potential environmental benefit from increased use of commercial nuclear power technologies results from the potential to dramatically reduce CO_2 emissions if nuclear electricity is substituted for coal- or gas-fired electricity generation. But this is likely to be a relatively expensive way to reduce U.S. CO_2 emissions.

Currently, in the United States, CO_2 is released from the production of nuclear electricity primarily during the enrichment stage of the uranium fuel cycle. These indirect emissions result from coal-fired production of the electricity required for operation of U.S. gaseous diffusion plants. In 2000, CO_2 emissions from electricity generation for uranium enrichment represented about 5 percent of total U.S. CO_2 emissions from coal combustion. In France, by contrast, the electricity required for enrichment is produced at nuclear power plants with virtually zero CO_2 emissions. If the energy for uranium fuel enrichment in the United States could be provided by nuclear generating facilities, instead of from existing conventional coal plants, CO_2 emissions from commercial nuclear technology could also be reduced almost to zero.

In 2000, U.S. nuclear and coal power plants together generated approximately 2,700 billion kWh of electricity (US DOE/EIA, Electric Power Annual 2000), mostly to meet baseload demand. The 104 U.S. LWRs operating in 2000 had an aggregate rated capacity of approximately 97,000 MWe. These plants delivered about 750 billion kWh (approximately 20 percent of total U.S. electricity production) while achieving an

average capacity factor[28] of 0.88. Additional capacity factor improvements by existing nuclear power plants could offset some fossil fuel-fired electricity generation in the United States, which would reduce emissions of CO_2 from the power sector.

Another potential benefit from expanding the production of electricity from nuclear power plants is the opportunity to make hydrogen using high-temperature processes. While nuclear plants have historically served baseload electricity demands, future advanced reactors that involve co-production of electricity and hydrogen could be operated with a load-following profile. Plants operated in this way would decrease electricity production and increase hydrogen production during hours of off-peak demand. Hydrogen produced in such plants could, in principle, be used to substitute for oil or other fuels in the transportation or building sectors of the U.S. economy. The potential contribution from nuclear power to U.S. hydrogen production was not considered in the Pew Center scenario building process.

Expanding electricity production from U.S. nuclear power plants could have significant negative environmental impacts, along with the positive impacts on future CO_2 emissions. The most dangerous environmental impact of any proposed expansion of commercial nuclear power results from the need for very long-term disposal of high-level radioactive waste. In today's political environment, many elected officials are also concerned about the potential risks associated with the transport of radioactive material by road, rail, or water. Each increase in production adds to the circulation of material that could be a target for terrorist acts. Unless one of the proposed closed nuclear fuel cycles can demonstrate commercial viability, this material will require absolute security through full-time protection and long-term management.

As of late 2002, no technological or institutional arrangements have demonstrated the ability to secure and store dangerous and toxic radioactive wastes for the necessary durations. The principal environmental risks associated with highly radioactive material include:

- Leakage of radioactive waste into groundwater and its subsequent release into surrounding ecosystems;
- Diversion of fissile material by national or sub-national groups and a subsequent threat or actual use in a nuclear weapon;
- Diversion and deliberate release of radioactive material by terrorist groups in a "dirty bomb"; and
- Inadvertent exposure of workers or others to radiation throughout the nuclear fuel cycle.[29]

Although a number of approaches to and potential sites for long-term radioactive waste storage have been proposed in the United States, none is operational, and few have been fully tested.

Energy Security Implications

One aspect of commercial nuclear power that adds to its attraction for the United States is that the fuel resource can be mined, concentrated, fabricated and enriched in the United States. Expanded development of nuclear power technologies, however, is unlikely to reduce U.S. energy import dependence significantly between now and 2035. Most of the energy security risks arising from U.S. energy import dependence are a consequence of importing petroleum and petroleum products, of which a very small percentage are used to generate electricity. Some analysts argue that new nuclear plants are so capital-intensive that further investments in nuclear power would draw investment away from other, cheaper methods of reducing U.S. oil-import dependence (e.g., Lovins, 2001). Nonetheless, increased nuclear power output could reduce future growth in demand for electricity generated from other fuels.

Perhaps more important, expanded use of nuclear power could increase requirements for plant and facility security in the U.S. energy sector. A large-scale expansion of nuclear power coupled with spent-fuel reprocessing in the United States could put significant quantities of bomb-grade material into circulation on U.S. roads and railways. Since considerably less than 10 kg of plutonium is needed to make a crude explosive device (and a crude radiological weapon, or "dirty bomb," designed to disperse radioactive material, can be made with far less plutonium or with other radioactive isotopes), the potential opportunities for radioactive releases could significantly increase, unless adequate security measures are implemented.

Expected Timing and Availability

The advanced nuclear technologies described above are progressing through various stages of research and development. None is commercially available today, and none has successfully demonstrated continuing operations at a commercially relevant scale. According to the Electric Power Research Institute, a not-for-profit arm of the U.S. utility industry, some early stage demonstrations of these systems are possible before the end of this decade. The development of passively cooled systems, including PBR technology, is probably the closest to commercialization. Some analysts believe that PBR technology could achieve commercial readiness before 2010 (EPRI, 2000), but others contend that this is very unlikely in the United States (Moniz, 2003). More complex designs, including IACS and other high-temperature options capable of producing significant amounts of by-product process heat, are unlikely to achieve commercial demonstrations before 2030.

Current and Expected Costs

The current cost of building light-water reactors in the U.S. is high. The last new nuclear power plants were ordered in 1978, and the most recently completed plant opened in 1995. The cohort of nuclear units built in the late 1980s and 1990s took as much as ten years to construct. In some cases, costs exceeded $3000 per kW of rated capacity. In this

price range, new nuclear plants are not competitive with new gas-fired or coal-fired alternatives.

New gigawatt-scale LWRs are widely considered to be uneconomic in competitive power markets. Some analysts argue that at 1990s prices, new nuclear power plants may not be competitive with the latest generation of wind power plants, if the windfarms are built in areas with good wind regimes (Williams, 2001). Recent estimates suggest that new LWRs built in the United States would produce electricity at a busbar[30] cost of $0.04 to $0.10 per kWh while new windfarms in sites with good wind regimes would deliver power at a price of approximately $0.03 to $0.08 per kWh, including a production tax credit (Sieminski, 2002).

It now appears that to be cost-effective, future generations of nuclear power plants would have to be installed at costs of $1000 to $1500 per kWe and construction would need to be completed in three to five years. Otherwise, advanced nuclear technologies will have difficulty competing in the United States with new, high-efficiency, combined-cycle natural gas power plants; distributed generation; demand-side management; or the latest generation of coal power plants. Nuclear power would be more attractive if national CO_2 controls or tightened air pollution regulations were implemented.

Issues Affecting Deployment of Advanced Nuclear Technology

The most important issues constraining the increased use of conventional LWRs and the development of advanced nuclear technologies include financial costs, infrastructure problems, institutional issues, and questions of social acceptance.

Financial Costs

The primary obstacle to widespread deployment of advanced nuclear technologies is cost. Since 1978 in the United States (and since the 1980s in most other market economies), the private sector has not financed a new nuclear power plant despite the introduction of liability caps and significant advances in planning for long-term radioactive waste disposal. Under today's conditions and under those that are likely to occur during the next decade, and in the absence of major new subsidies, most United States investors and electricity supply companies are more likely to build natural gas-fired, combined-cycle turbines, coal-electric generation, or wind power plants to meet incremental electricity demand rather than investing in advanced nuclear technologies. However, if capital costs of new nuclear plants fall into the range of $1000 to $1500 per kWe, nuclear power will again become a competitive option.

Infrastructure Issues

Long-term waste management is the major infrastructure issue for conventional nuclear technology. Although, in July 2002, a site at Yucca Mountain, Nevada, was officially designated as a repository for spent nuclear fuel and high-level radioactive waste, the

storage technology remains unproven and the U.S. DOE has not yet submitted an application to the Nuclear Regulatory Commission to license the facility. The Nevada state government opposes the development of this site and plans to continue its opposition through the federal court system. According to the U.S. DOE's Office of Civilian Radioactive Waste Management website, "it is uncertain when plans for repository shipments will be finalized" (US DOE, 2003). Many state governors have objected to transport of out-of-state wastes across their territory, unless a waste transport plan is proven to be safe. Without an approved and licensed infrastructure for waste handling and long-term management, rapid expansion of nuclear power systems in the United States will be difficult.

Institutional Issues

In the past, radioactive waste storage was managed in the United States so that certain levels of leakage are permitted under the assumption that these levels represent no substantial dangers to the public or to surrounding ecosystems (Benson, 2001). Under this paradigm, operational specifications for each storage site are set on a case-by-case basis. Regulators use probabilistic modeling techniques to assess performance of each site, allowing explicit consideration of uncertainty.

Even after the physical infrastructure of a national waste management repository has been constructed and a waste storage technology demonstrated, the management of long-term radioactive waste would be a key institutional challenge for nuclear power technology. No organization or agency has identified a management regime that is capable of ensuring the safety and security of operations at a high-level nuclear waste repository for periods on the order of a thousand years.

Social acceptance issues

The social acceptance of nuclear power technology has been problematic. Many elements of civil society resist nuclear power technology and oppose the construction of nuclear power facilities. Most of this resistance reflects public perceptions about the risks of accidents and sabotage.

The public fear of accidents at nuclear power plants is generally not based on a quantification of the probability of various failure sequences. Rather it reflects individual personal responses to the prospects of low-probability, high-consequence events. Many Americans (including some leading political figures in the United States) have been unwilling to accept on faith the assurances of the scientific community that the likelihood of future accidents is diminishingly small.

Benson (2001) observes that the best way to ensure public acceptance is to involve all key stakeholders, including the members of affected communities, in major decisions. She concludes from past U.S. experience with radioactive waste storage technology that community involvement is critical to the overall success and willing acceptance of any controversial new technology. Only if local communities are engaged early and actively

are technology developers likely to persuade affected communities to accept advanced nuclear technology.

Issues Affecting the Deployment of Advanced Nuclear Technologies in the Pew Center Scenarios

Electricity supply from commercial nuclear plants varies across the Pew Center scenarios, but none is a high-nuclear case and none reflects a shutdown of the commercial nuclear industry. In *Awash in Oil and Gas*, nuclear electricity supply gradually declines. In the *Technology Triumphs*, output from commercial nuclear power plants in the United States remains constant, with retirements of aging facilities just offset by improvements in the operational efficiency (and up-rating of capacity) at remaining plants and the introduction of a few advanced reactor units at existing nuclear sites. In *Turbulent World*, nuclear electric output first increases as new smaller, advanced reactor designs are put into service. Then, public acceptance of this technology declines, and output falls to approximately 5 percent below the year 2000 levels. Implementation of the simulated climate policy does not alter the outcome for nuclear power between any of the base case scenarios and their respective policy overlay cases.

Conclusions

A variety of advanced nuclear power technologies are in the late stages of research and development in the United States. Some of these technologies may offer lower costs and increased security compared to conventional nuclear technologies, and all offer carbon benefits over conventional fuels. For these technologies to play a significant role in U.S. energy strategy during the next thirty years will require a rapid ramp-up in their development and commercialization. Accelerated development of advanced nuclear technologies will require large investments; the risks associated with these technologies are not yet fully quantified. Many technical, economic, and institutional challenges associated with such scale-up remain to be addressed and resolved.

The advanced nuclear technology that is closest to commercialization is the advanced water-cooled reactor. Proponents of this technology claim significant benefits in terms of reduced costs of construction and increased resistance to accidents during routine operations. But AP-600, the advanced water-cooled reactor that is farthest along in the development process, has just been "taken off the table" by its manufacturer.

Regardless of which advanced nuclear power technology is developed, the United States will have to create the physical infrastructure and the institutional regime necessary to manage radioactive waste. If an acceptable waste management scheme is licensed and made operational in the next decade, future expansion of nuclear power technology could occur. If not, the prospects for expansion will be limited and some existing commercial nuclear power plants may be forced to close.

The key challenges to a rapid development of advanced nuclear power technologies include potentially high cost, increased risks of accidents, the possible proliferation of nuclear weapons, and public acceptance of these technologies.

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Distributed Generation

(authored by Pew Center staff)

Distributed generation (DG) is modular electric generation located close to the point of use. Generating systems can be combustion-based (including reciprocating engines, micro-turbines, and Stirling[31] engines) or non-combustion-based (including PVs, wind, micro-hydro, and fuel cells). DG units are often operated remotely using control interfaces, which are now commonplace in some countries. Although the term "micro-power," referring to units that generate less than 10 MW, is often used interchangeably with distributed generation, DG is not actually restricted by size. DG offers a number of potential benefits over conventional systems; however, a number of institutional, technical, and market barriers hinder its adoption.

DG units may be either independent from or connected to the grid. Connecting to the grid allows owners of DG units to sell power back to the grid in times of excess and to be backed up by the grid in case of the unit's failure, but connecting to the grid can also be expensive and complicated, as utilities have connection requirements and fees.

Benefits of Distributed Generation

Efficiency

A typical coal-fired power plant has an overall efficiency of 30 to 38 percent and a large natural gas combined cycle plant, 40 to 50 percent (higher heating value). Distributed generation technologies have electrical efficiencies ranging from 25 to 45 percent (see Table 1). Because DG systems are located close to the point of use, it is often possible to use their waste heat in industrial processes and to control the temperature of nearby buildings. Using this combined heat and power (CHP) approach, which has been widely implemented in a number of European countries and Japan, combustion-based DG systems can achieve overall efficiencies of up to 80 to 90 percent.[32]

Since power from DG is used close to its site of production, DG also avoids losses of electricity during transmission and distribution, which average around 10 percent when transmitting electricity into an urban area from outside.[33] However, for DG that requires fuel (including all combustion-based DG and fuel cells), additional fuel-delivery infrastructure may be necessary.

Risk Avoidance

Delivered power from distributed generation with on-site backup may be more reliable than that from centralized plants. This increased reliability can benefit both the users of DG and those who receive their power from the grid. Around 95 percent of the power outages in the United States are caused by transmission and distribution system failures, due to damage of lines from weather or to overloading of lines from excessive demand.[34] Users of DG are protected from these interruptions. Moreover, under certain

circumstances DG can help power from the grid be more reliable by lightening loads on distribution equipment (such as power lines and transformers) which decreases the likelihood of outages. A sufficient quantity of interconnected DG can also back up other DG units or the power grid.[35]

Electricity from DG may also be of better quality than power from the grid because DG is less likely to create spikes and dips in voltage than power from the grid. Imperfections in distribution and transmission of power from centralized plants may prevent consistent delivery of power to users. Much electrical equipment requires a constant supply of power and can suffer damages from slight fluctuations in voltage. Many consumers are willing to pay a premium to be protected from this risk.

In addition, DG systems can use a wide variety of fuels and energy resources, including renewables, which lessen vulnerability to fluctuations in the price of fossil fuels. Micro-turbines can be powered on a range of gaseous fuels, Stirling engines can run on any energy source, and photovoltaics are inherently a distributed technology. If, however, the majority of DG electricity is generated from natural gas, this may increase demand and hence price volatility.

Ease of Planning

Due to their small size and modularity, distributed generation technologies can be planned, sited, and built more quickly than conventional centralized power. Modular units are built in factories and can be transported and installed at a site in a few hours. In addition, modular systems are easier to modify to meet changes in demand than conventional systems.[36] However, because DG is located close to the point of use, which may be in a populated area, DG projects may face local opposition related to noise, safety, and local air pollution concerns.

Environmental Benefits

Renewable DG and DG-CHP is generally environmentally beneficial compared to central station generation using fossil generation. However, local air pollutant emissions remain a concern for non-renewable DG and DG-CHP. Renewable distributed generation technologies will not produce CO_2 or SO_2, and most will not emit local air pollutants (one exception may be combustion of biomass). Of course, centralized renewable power also has these advantages.

For fossil fuel-fired DG, the ability to utilize heat in a CHP application results in high overall efficiencies and hence reduced CO_2 emissions. As fossil DG is primarily natural gas, there are no SO_2 emissions. In addition there are some DG technologies (fuel cells, Stirling engines) with very low levels of local air pollutants. The level of CO_2 and SO_2 emissions from DG systems depend only on the content of carbon or sulfur in the fuels and the efficiency of generation. Local air pollutant emissions (including NO_X, CO and PM_{10}) from DG systems depend on the characteristics of combustion in the machine.

Typical air pollutant emissions from DG are discussed later and summarized in Table 1 below.

Energy Security Implications

The energy security implications of distributed generation concern facility security, rather than oil import dependence. The decentralized nature of a distributed electricity system means smaller, less attractive targets compared to large centralized plants. A DG system based on natural-gas-fired units may have several additional security benefits compared to a system built around central-station power plants: (1) the system would rely less on the transmission and distribution grid, (2) natural gas distribution systems are less prone to cascading failures than are electric power grids, and (3) natural gas DG systems are more robust due to widespread dual fuel capability and local natural gas storage facilities.[37] However, natural gas transmission pipelines are also vulnerable to attack and disruption, particularly in remote areas where repair may be difficult.

Barriers to Distributed Generation

To become widespread, DG will need to overcome several barriers that now stand in its way. Barriers arise from a combination of the following:

- Regulatory inertia;
- True costs of integrating and interconnecting DG with a largely centralized structure;
- Resistance to DG by centralized utilities who may view DG as a competitive threat

The regulatory structure regarding siting, permitting, and emission requirements for power generating systems was designed for large, centralized plants, not small generators. Most building, electrical, and safety codes do not account for DG systems.[38] In addition, approximately 20 states do not yet have net-metering rules, which allow the owner of a DG system to pay utilities for the net amount of power used, by selling power to the grid during times of excess to offset the purchase of power from the grid during times of need. In establishing net metering policies, the price paid for DG power sold to the grid should reflect its relative value (increased if DG power alleviates bottlenecks in the T&D system or meets peak summer power, or decreased if sold at night). In 14 of the 30 states that have net metering policies, only renewable sources are covered, excluding DG-CHP.[39]

There are fair and reasonable costs for DG interconnection. For example, the utility has to provide emergency and stand-by power and ensure safe operation. The owner of the transmission and distribution system is justified in charging a fee for the connection of a DG unit to the grid, but that fee should not exceed the total cost of the service provided. Utilities, however, may have a disincentive to facilitate this interconnection, and thus impose excessive interconnection costs. Regulated utilities that earn a financial return by the amount of electricity they deliver and the amount of capital they deploy may view

DG as eroding their rate-paying base, while deregulated utilities may view DG as a competitive threat.

Regulated utilities may establish barriers to entry to DG. Imposed barriers can include complex power purchase agreements (originally designed for much larger generators), stranded asset charges for both existing generation and transmission infrastructure, and stand-by charges to reflect the costs of grid-connected backup. Utilities may also impose requirements on owners of DG systems before allowing them to connect to the grid. These requirements can be costly, and often vary by utility. The lack of standardization and transparency of interconnection requirements poses an obstacle to manufacturers of DG technology that operate in regional or national markets. These requirements, combined with the fees that utilities charge, may double the cost of small-scale power.[40]

Environmental Issues

In some circumstances fossil-fueled DG technologies can increase local air pollution compared to new, central-station, natural gas combined cycle (CCGT) plants. However, most types of DG demonstrate environmental performance that is superior to centralized coal-fired power plants. The relative emission rates of DG technologies are much improved in CHP applications. See, for example, the comparison between DG and centralized electricity plus heat boiler plants in Table 1. Table 1 illustrates that a CHP natural gas engine has lower NO_X emissions than CCGT plus heat boilers. Very low-emission DG technologies include fuel cells and micro-turbines. Gas engines perform poorly on CO and unburned hydrocarbons, while diesel engines have poor emission characteristics in general.

However, even given relative emission rates, since DG is by definition located relatively close to end users, it may be closer to population centers; thus the resulting pollution from fossil-fueled DG may cause greater human exposure than emissions from remotely sited, central-station power plants.

Table 1: Efficiency and Emission Characteristics of DG Technologies

	Efficiency	CO_2	SO_2	NO_x	CO	PM10	HC
	%HHV	g/kW-hr	g/kW-hr	g/kW-hr	g/kW-hr	g/kW-hr	g/kW-hr
Distributed Technologies							
Gas ICE	29 (28-36)	625	0.032	0.5 (0.3-0.9)	1.8	0.014	0.54
Diesel ICE	35 (33-42)	695	1.25	2.13 (1.3-4)	2.8	0.36	1.65
Micro-turbine	25 (20-26)	725	0.037	0.2 (0.13-0.28)	0.47	0.041	0.14
Fuel Cell	38 (38-42)	477	0.024	0.015 (0.01-0.02)	0	0	0
Gas Turbine	29 (25-31)	625	0.032	0.29 (0.18-0.55)	0.42	0.041	0.42
Conventional Technologies							
CCGT	50 (47-57)	363	0.019	0.195 (0.105-0.39)	0.07	0.041	0.05
Coal Steam Turbine	33 (31-34)	965	5.64	1.7 (0.9-3)	0.07	0.136	0.05
Heat Boiler	90 (85-93)	201	0.01	0.22 (0.12-0.35)	0.47	0.041	0.14

Natural gas powered unless otherwise noted.
Source: Farrell and Strachan[41]

Costs

Distributed generation technologies benefit from an economy of scale through the production of a large number of smaller units, whereas the economy of scale of centralized power results from the construction of a single larger unit.

DG can be attractive to vertically integrated utilities, especially when transmission and distribution systems are already at their capacity. According to some sample calculations by Arthur D. Little, it costs utilities $.02-04/kWh to meet new demand with a central plant under no constraints, $.04-.07/kWh when generation is constrained, $.07-.18/kWh when transmission and distribution are constrained, and $.09-.22 when generation, transmission, and distribution are constrained. Meeting new demand with a large natural gas-fired reciprocating engine costs $.07-.15/kWh. Rather than upgrading the transmission network to handle new demand, it can be more cost effective to add DG units where the power is needed, depending on available fuel infrastructure. DG can also be cost-competitive for transmission and distribution companies. However, in some

cases laws prohibit transmission and distribution companies from owning generation, in which case they could contract with a third party to own it.

The economic attractiveness of DG to consumers is a function of several variables. The cost savings of DG to the consumer increases with the grid cost of delivered electricity and with added benefits of DG, and decreases with DG capital charges, fuel costs, O&M costs, and other added costs. Added benefits may include reduced energy costs for producing heat, decreased exposure to electricity price volatility (but potentially greater exposure to natural gas price volatility), increased power reliability, and higher quality power. According to A.D. Little (1999), these benefits may be valued at up to 3.7¢/kWh. Grid-side benefits (transmissions and distributions losses, etc.) can add as much as 3.2¢/kWh. Added costs may include standby charges and non-by-passable charges for not buying from the grid (e.g. competition transition charges in California) (2.7¢/kWh).[42]

Expected Timing and Availability

Estimates of future DG market penetration vary widely. Studies by the Electric Power Research Institute and other organizations have indicated that DG could provide anywhere from 5 to 40 percent of new annual capacity in the United States by 2010.[43]

As a point of reference, the Netherlands installed 1500 MWe of DG, or 6 percent of its electricity capacity, over 10 years from 1990 to 2000. This was possible as a result of partnerships between utilities and DG adopters.[44]

Relevance to Scenarios

All three scenarios see a rise in DG, but the factors driving the increase, as well as the fuels used for generation, vary by scenario.

In *Awash in Oil and Gas*, DG begins to come on-stream in applications requiring high reliability of supply. Most of the initial investment in DG is fossil-fueled.

In *Technology Triumphs*, public policy, led by the states, increasingly recognizes the reliability benefits and environmental superiority of DG. This promotes expanded public and private investment in R&D for new technologies, which become commercialized in the United States and open up fast-growing export markets. Net metering spreads nationwide by 2005, and by 2010, the full cost of DG systems that are integrated into residential structures can be financed with conventional home mortgages.

In *Turbulent World*, security concerns drive the advancement of DG. National interconnection standards are agreed to in 2010. By 2020 "gated communities" opt out of the grid with residential DG; fuel cells and micro-turbines are used widely in commercial and industrial CHP facilities.

Conclusions

The main challenges to DG are structural and regulatory, rather than technological (although fuel cells and renewable DG technologies require further development). Many promising DG technologies are available, as are remote operation and control interfaces for DG units, but the current grid-based utility system is not well positioned to take advantage of them. Certain DG technologies—especially CHP and renewables—have the potential to decrease GHG emissions and provide various other benefits, but implementation of DG remains a challenge, because of regulatory barriers, institutional inertia, and genuine concerns over system impacts of widespread DG diffusion. The adoption of DG technologies requires a merging of paradigms—the current paradigm of large centralized power, and a new system of generally smaller, decentralized power generation.

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Endnotes

[22] The authors wish to acknowledge the contribution of Naomi Pena of the Pew Center on Global Climate Change to the preparation of this assessment.

[23] Depending on assumptions about future use of fossil fuels, atmospheric stabilization targets and uptake of CO2 by oceans and the terrestrial biosphere.

[24] Such a car has been designed; see www.hypercar.com.

[25] Plant-to-plant variation makes it difficult to define a typical plant; these are average values.

[26] Cost effective means that the marginal investment cost is less than the discounted savings due to the improved efficiency of operations.

[27] Above a certain temperature (called the critical temperature), a gaseous vapor can no longer be liquefied, regardless of the pressure of its surroundings. Gases that remain above this temperature are referred to as supercritical fluids.

[28] The capacity factor of an electricity generating plant is defined as the ratio of the net electricity generated per year, compared to the maximum that could be generated by that plant if it operated at its full rated capacity for the entire period.

[29] Risks of occupational exposure to radioactivity occur throughout the nuclear fuel cycle and may actually be more severe in other stages of the fuel cycle than during the waste storage and disposal stage.

[30] Busbar is the name given to the point where an electric generating station is connected to the rest of the electricity grid. It is often used to identify the production cost of electricity at the power plant gate.

[31] An internal combustion engine is designed for a single type of fuel that is burned inside the cylinder. In contrast, a Stirling engine is an external combustion engine that can utilize any heat source; if fuel is combusted directly, it is done so outside the cylinder.

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