Title
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Publication Date
1989

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Reprint
UCTC No. 11

The University of California Transportation Center

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Reprinted from
Annual Review of Energy
Vol. 14, pp. 375-424 (1989)

UCTC No. 11

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Annu. Rev. Energy. 1989. 14:375–424

TRANSPORTATION ENERGY FUTURES[1]

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INTRODUCTION

The search for petroleum alternatives is not new. Ever since the turn of the century, when petroleum became the dominant transportation fuel, authoritative sources have warned occasionally of impending oil shortages (1, 2). When oil prices rose or oil depletion seemed imminent, interest and investments in oil shale, ethanol, coal liquids and gases, and tar sands surged; when oil prices subsided or estimated costs of alternatives escalated, interest and investments in the alternatives waned. Not until recently have several countries actually replaced substantial quantities of petroleum transportation fuels: Canada and South Africa built large production plants to produce gasoline and diesel fuel from tar sands and coal; Brazil replaced most gasoline with ethanol fuel; and New Zealand replaced almost half its gasoline with natural gas-based fuels.

These four countries are the exception, however. The transportation sector worldwide has remained almost totally dependent on petroleum fuels. As other energy sectors, such as electricity production, diversified into nonpetroleum sources, transportation gained a growing proportion of the world's petroleum consumption. In the United States, for instance, the transportation

[1]Abbreviations used: CH_4, methane; CO, carbon monoxide; CO_2, carbon dioxide; HC, hydrocarbons; NO_x, nitrogen oxides; N_2O, nitrous oxide; O_3, ozone; PM, particulate matter; SO_x, sulfur oxides; NG, natural gas; CNG, compressed NG; LNG, liquefied NG; RNG, remote NG; SNG, substitute NG; EV, electric vehicle; ICEV, internal-combustion engine vehicle; CNGV, CNG vehicle; LNGV, LNG vehicle; NGV, NG vehicle; LH_2, liquid hydrogen.

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0362-1626/89/1022-0375$02.00

sector, which has relied on petroleum for 97–98% of its energy needs for decades, increased its share of the domestic petroleum market from 53% in 1973 to 63% (74% in California) in 1987 (3). Transportation has increased its share of the petroleum market in almost every country, with the notable exception of the four countries identified above.

The virtual absence of nonpetroleum fuels in the transportation sector suggests that the barriers to alternative energy are greater than in other sectors. This delayed introduction of new fuels, and the resulting dependence on petroleum, could be costly in the medium term and untenable in the long term.

Why Alternative Fuels?

The fundamental problem is that the international petroleum market does not allocate oil resources in a socially efficient manner. It does not account for large environmental impacts, and it is volatile and politicized, distorting energy decisions through inappropriate price signals and uncertainty. Four major problems and costs are not captured in market prices:

1. Energy security (dependence on insecure petroleum suppliers)
2. Indirect economic costs of importing energy
3. Global warming
4. Urban air pollution.

Thus, even though current prices in energy markets indicate that alternative energy sources and alternative fuels are not competitive, there may still be important reasons for introducing them.

ENERGY SECURITY The United States is becoming increasingly dependent on oil imports. The trend is unmistakable: domestic oil production is declining and domestic oil consumption is increasing (Figure 1). For a scenario of high oil prices, the US Energy Information Administration forecasts that net oil imports will increase from 6.0 million barrels per day in 1987 to 8.6 million barrels per day in 2000. Assuming low oil prices, oil imports are forecasted to increase to 11.7 million barrels per day in 2000, representing 60% of total oil consumption (4). The import gap is likely to continue widening thereafter.

It is unclear how risky it is to depend heavily on imported oil, and how urgent it is to develop domestic transportation fuels. The severity of the problem depends on one's view of the future: Will OPEC countries agree and adhere to production quotas? Will anti-western factions gain control in the major exporting countries and severely restrict oil output? Will large amounts of petroleum be discovered elsewhere? Will advances in enhanced oil recovery lead to increased US oil production? The total external (nonpriced)

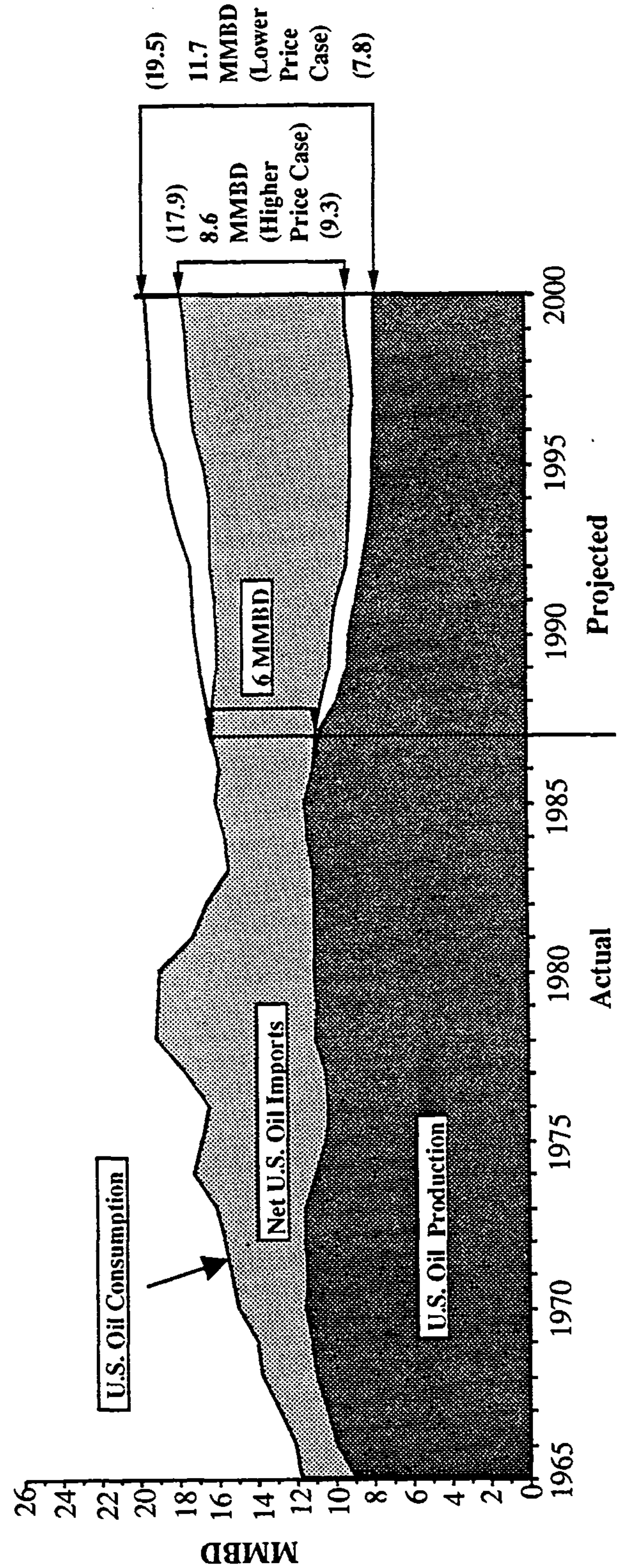

Figure 1 History and outlook for US oil imports. Source: US Energy Inf. Admin. 1989. 1989. *Annual Energy Outlook 1989*. Washington, DC

economic cost of oil dependence is difficult to measure; one must estimate not only the probabilities, magnitudes, and lengths of such events, but also the responses of importing countries to supply disruptions or price rises, the cost of military activity to protect oil supplies, the cost of oil shipments in the Middle East and other important supply regions, and the cost of maintaining the Strategic Petroleum Reserve (now containing over 500 million barrels). The sum of these costs may exceed $20 per barrel of oil (5).

INDIRECT ECONOMIC COSTS OF OIL IMPORTING Dependence on oil imports is more than a security problem, however. It also has large indirect economic costs, resulting from oil price volatility, rising world oil prices, and large outflows of funds to producing countries. The availability of a credible alternative (and/or reduced petroleum consumption) would dampen oil price volatility, restrain price increases, and reduce payments for oil.

Price volatility creates uncertainty and distorts investment decisions, resulting in a preference for short-term investments, while the absence of a credible alternative to petroleum transportation fuels results in oil prices being higher than they would otherwise be. This effect, illustrated in Figure 2, holds for the long term as well as in response to rapid price escalations.

An initial effort to model the effect of alternative fuels on world petroleum prices, using a world energy trade model first developed at Stanford University and now modified for use by the US Department of Energy Policy Office,

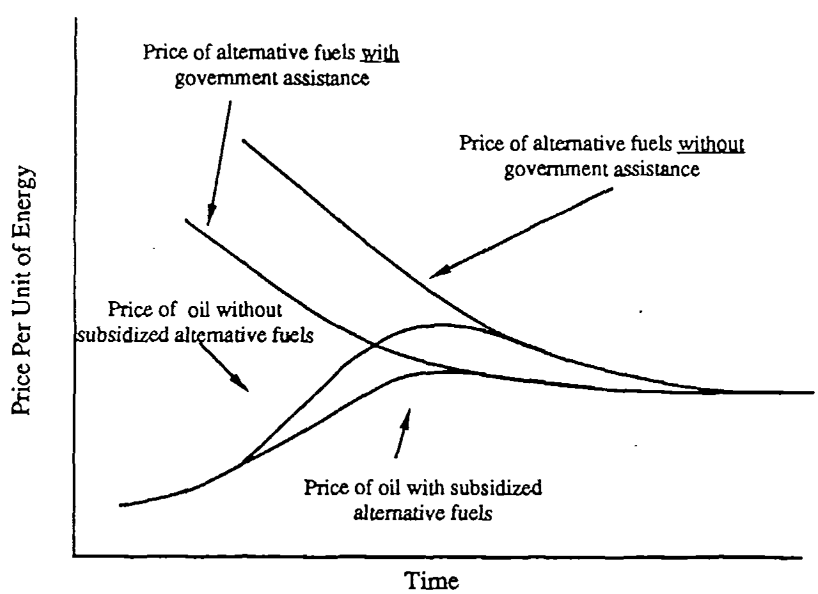

Figure 2 Conceptual representation of impact of alternative fuels on world oil prices. Source: adapted from Ref. 7

indicates that substituting an alternative fuel for 2 million barrels per day of gasoline fuel, thereby reducing world oil demand, would lower the world oil price by about $2 per barrel when oil is priced at $34 per barrel (6). If this analysis is correct, those 2 million gasoline-equivalent barrels would reduce the import cost of oil to the United States by about $18 million per day ($6.6 billion per year), or $9.00 per gasoline-equivalent barrel of alternative fuel.

The benefit of suppressing short-term oil price spikes may be even larger, because the spikes may be steeper and more disruptive. If oil-importing countries wait for higher prices, they will not be able to respond with alternative fuels for many years. High prices could be maintained for 10 years or more as the United States and other oil importers struggle to expedite the transition to nonpetroleum fuels and replace vehicles that consume only gasoline and diesel fuel.

Finally, rising imports of oil impose large indirect costs on the national economy, since the outflow of funds to pay for imported oil shrinks demand for domestic goods and services. This cost is difficult to estimate because it depends on hard-to-assess factors such as how much the exporting nations reinvest their earnings in the United States, what they invest in, the response of exchange rates to changes in terms of trade, and employment in the United States exporting industries (8). In any event, it has been estimated that the macroeconomic external costs of rising imports may run as high as $50 per barrel of oil (9–13). Thus, even though they cannot be accurately quantified, indirect economic costs are another motivation for introducing alternative fuels.

GLOBAL WARMING The third problem, global warming, is caused by increasing atmospheric concentrations of carbon dioxide and other "greenhouse gases," many of which are produced by the combustion of coal, oil, and natural gas; it is now attracting much more attention than energy security or indirect economic impacts, partly because its potential costs are much greater, although more speculative.

Transportation is a large source of greenhouse gases, accounting for about 25% of greenhouse gases emitted in the United States (14). As scientific evidence becomes more certain, the possibility exists that a strong commitment will be made to reduce the use of carbon fuels. It is unlikely that carbon dioxide emissions could be reduced economically by adding control systems to vehicles or refineries. The most feasible strategy for reducing carbon dioxide emissions from transportation is less consumption of fossil fuels, either by increasing fuel-efficiency or using nonfossil energy sources, such as biomass, hydrogen made from water with nonfossil electricity, or electricity made from nonfossil fuels (primarily solar, nuclear, or hydroelectric power).

AIR POLLUTION The fourth motivation for introducing alternative transportation fuels is, in the United States, politically the most potent: air pollution reduction. The use of petroleum for transportation results in large quantities of pollutant emissions from vehicles, refineries, and fuel stations. These pollutants cause acute and long-term illnesses and premature death, reduce agricultural productivity, damage materials, reduce visibility, contaminate groundwater and coastal areas, and more. These damages, from the highway transportation sector alone, may amount to $10–200 billion per year, the large range depending mostly on uncertainty about the number of deaths and illnesses due to pollution and about the monetary value to be assigned to deaths and illnesses (15).

In the United States pollution costs are addressed indirectly by institutionalized rules for improving air quality. In the near term two specific requirements will be the driving force for introducing clean-burning transportation fuels: (*a*) stringent new emission standards for diesel vehicles and (*b*) attainment of existing ambient air quality standards for the two pollutants due primarily to transportation: ozone and carbon monoxide. In 1987, the United States Environmental Protection Agency reported that 107 metropolitan areas in the United States violated the primary health standard for either ozone or carbon monoxide. Such "nonattainment areas," unless they make significant progress toward meeting the standards, risk losing federal funds for highways and other infrastructure and incurring various sanctions that are still being debated. Attainment is a major political issue.

In summary, the problem associated with continued reliance on petroleum fuels is not simply the prospect of running out of oil sooner or later, but rather a range of social costs: the economic or welfare losses resulting from air pollution, global warming, loss of income to oil exporters, and potential supply disruptions or price rises. Because the price of petroleum does not fully reflect these costs, private markets are less attracted to alternative fuels than is society as a whole. In short, private enterprise, and public decisionmakers, to the extent that they rely on market signals alone, will always show less interest in those alternative fuels that have net benefits of the type suggested above than is socially and economically desirable.

Moreover, as shown later, there are also large start-up barriers to alternative fuels in addition to the external cost problems discussed above. Because of these start-up barriers, and the market flaws discussed above, new transportation fuels will not be introduced in a timely and economically efficient manner unless government intervenes. The difficult task, and the objective of the rest of this paper, is to specify under what conditions and to what extent the different alternatives should be pursued.

What we will not do is address production and end-use options for prolonging the petroleum era in transportation—such as enhanced oil recovery, heavy oil, and lower emissions and improved fuel-efficiency of petroleum-powered vehicles—although it is important to note that improved emission control knowledge can be applied to alternative-fueled vehicles and improved fuel-efficiency is critical to the marketability of vehicles powered by alcohols, gases, or electricity.

PATHWAYS

There are many alternative resources, fuels, and technologies that can be used to replace today's petroleum-based gasoline and diesel transportation fuels.[4] The resources include biomass materials, coal, oil shale, tar sands, natural gas, water, and nonfossil electricity sources, such as nuclear, hydroelectricity, and solar power. These resources can be converted into a wide range of fuels, including ethanol and methanol, plant oils, petroleumlike liquids, methane, hydrogen, and electricity. Various technologies may be used to convert the resources into usable fuels, and the fuels may be stored in various ways and burned by various engine technologies.

Here we collapse the multitude of options into five sets of choices: petroleumlike mineral fuels, biomass fuels, methanol from natural gas and coal, methane fuels, and hydrogen and clean electricity. These energy choice sets are labeled pathways, because the emphasis is on direction of change and transition opportunities, not on specifying particular end-state market penetration situations. The pathways are analyzed with respect to feedstock and fuel attributes, environmental impacts, and the values and beliefs that would lead to selection of each set of energy options. As we indicate later, the paths are not necessarily mutually exclusive or unique; indeed, in a large country such as the United States, with its climatic and geographic diversity, wealth of resources, and decentralized political and economic system, pursuit of multiple options is probably desirable. The pathways formulated here present a framework for organizing, describing, and assessing those options.

[4]An important assumption in our treatment of alternative fuels in this paper is that even though motor vehicles have adverse environmental impacts and are large energy users, they will remain the principal mode of transportation for the foreseeable future. No major political or economic forces or technological breakthroughs are discernible that will cause the demise of cars and trucks. The major emerging research initiatives in transportation, such as the development of automated vehicle guidance and control, perpetuate the motor vehicle. Vehicle ownership and usage continues to increase worldwide even in countries with shrinking income, high vehicle taxes, and gasoline priced at $3 per gallon and more. Before gasoline prices rise high enough to have a major impact on motor vehicle purchase decisions, alternative fuels will be economically attractive, even by private market criteria. Thus energy and environmental problems may motivate a transition to more expensive, clean-burning, domestic energy resources, but all evidence indicates that these higher costs would not lead to the demise of motor vehicles.

PETROLEUMLIKE MINERAL FUELS ("SYNFUELS")

History

Until about the mid-1980s, the preferred options for replacing petroleum in the United States were petroleumlike liquids manufactured from oil shale and coal. These fuels options have been known for a long time.

Commercial oil shale plants operated in France, Australia, Scotland, Brazil, and the United States in the 1800s and early 1900s (16, 17). More than 100 oil shale corporations were established in the 1920s oil shale "rush" in the western United States (18). The shale oil liquids were generally burned directly, since they were not high enough in quality to use in engines.

Commercial coal liquids production dates to Nazi Germany. During World War II Germany produced between 100,000 to 200,000 barrels per day of coal liquids, mostly as aviation gasoline (19). Beginning in the 1950s, South Africa built three plants to convert coal into gasoline and other liquids and gases; production reached 74,000 barrels per day in the 1980s. The South African technology is a direct descendant of German World War II technology.

Petroleumlike coal and oil shale liquids dominated the public and private energy agenda in the United States during the 1970s and early 1980s. Virtually all the major energy studies in the United States during that time, as well as government energy policy, favored petroleumlike fuels from coal and oil shale over methanol, ethanol, and natural gas fuels (20–22). Public and private R&D was heavily weighted toward direct liquefaction of coal (23). Indeed, as late as 1981, 25 of the 31 most advanced projects considered by the United States Synthetic Fuels Corporation were intended to produce petroleumlike liquids, not methanol or gaseous fuels (24).

Advantages of Petroleumlike Fuels

Petroleumlike mineral fuels are attractive in several ways. First, they rely on abundant, if finite, resources. Worldwide, proven coal reserves are 3½ times the size of proven petroleum reserves, while in the United States they are almost 30 times as large (25). In the United States, "identified" oil shale reserves, a category that includes both economically and uneconomically recoverable reserves (no accurate measurement of proven oil shale reserves has ever been made), are 8 times as large as proven (economically recoverable) petroleum reserves (26). The use of petroleumlike synfuels, thus, could greatly reduce and perhaps even eliminate US dependence on imported oil.

Second, since these fuels are similar to conventional gasoline and diesel fuel, no changes in motor vehicles would be needed, and the only changes required in fuel distribution technology would be extension of the pipeline network to new production facilities. Some existing oil refineries could be used for final upgrading of the fuels.

Third, although the costs of producing petroleumlike liquids from coal and oil shale are uncertain because the technology is still undeveloped, convincing historical evidence from similar industries indicates that these costs will drop 50–70% over time. The cost to produce liquid fuels in first-generation plants may be $100 or more per oil-equivalent barrel, but these costs will be reduced substantially by later-generation technology (27). The US Synthetic Fuels Corporation, using Rand Corporation studies of cost reductions associated with learning curves in several processing industries (28), concluded that with third-generation technology, petroleumlike fuels from oil shale could be produced for $35–40 per barrel and medium-Btu gas could be produced from coal for $25–40 (29). Recent studies, based on progress at the two-stage liquefaction facility operated by the US Department of Energy in Wilsonville, Alabama, are in general agreement stating that coal liquids ultimately could be produced for as little as $30 per barrel (30, 31).

Disadvantages of Petroleumlike Fuels

However, petroleumlike fuels have considerable disadvantages. The most serious is that their introduction would further degrade the environment (32). Because these fuels generally contain more carcinogenic and toxic compounds than gasoline and diesel fuel, but are otherwise similar, combustion will produce as much of the regulated pollutants (CO, HC, and NO_x), and at least as much unregulated pollution, as combustion of gasoline and diesel fuel. And the air quality impacts of producing fuels from coal and oil shale are much greater than those of producing gasoline or diesel fuel (Table 1). Oil shale activities also generate huge amounts of solid waste, about 20 to 55 kg per gallon of fuel, which contain large amounts of toxic materials that can leach into water supplies; such activities also use large amounts of water, three or more barrels per barrel of shale oil (37, 38). These impacts are especially serious because the densest concentrations of oil shale are in the arid and fragile environment of the Colorado River basin. Large-scale production would scar large areas of land for hundreds of years. Coal production also has potentially severe impacts, generating large quantities of solid waste (though less than oil shale) and requiring large volumes of water. Underground coal mines in addition are dangerous, with high rates of illness, injuries, and fatalities. Surface mines scar large land areas.

Possibly the most serious environmental impact is the large amount of carbon dioxide emitted by the use of coal- and oil-shale-based fuels. Coal- and oil-shale-based fuels produce about twice as much carbon dioxide as petroleum (39). If the scientific consensus on the seriousness of the greenhouse effect is translated into policy, coal- and oil-shale-derived fuels could be eliminated by this criterion alone.

A second disadvantage is that coal and oil-shale fuel plants are very risky,

Table 1 Comparison of air pollutant emissions from energy conversion processes, grams/million Btu of output, with controls

Product/process	Feedstock	Emissions					
		Particulates	SO_X	HC	NO_X	CO	CO_2
Syncrude/pyrolysis	oil shale	10–35	3–16	3–15	50–150	3–16	55,000
Syncrude/Liquefaction[a]	bituminous coal, 4% S	10–25	18–60	0.3–3	4–210	3–5	50,000
Ethanol/fermentation	corn	45–370	37–1500	5–140	100–830	10–170	—
Ethanol/hydrolysis	crop residues	100–200	800–1100	—	500–600	—	—
Methanol/gasification[b]	subbituminous & lignite coal, 0.5% S	1–25	30–200	100–500	15–150	—	65,000–90,000
Methanol/Texaco gas.[c]	coal	9	113	—	82–276	13.7	125,000
Methanol/gasification	wood	0–30	0	—	10–200	—	—
SNG/coal gasification[d]	bituminous coal	5.7	28	—	82	—	—
SNG/coal gasification[e]	lignite coal	11	108	no limit	63	no limit	no limit
Petroleum/refinery	crude oil	2	11	10	9	—	—
Petroleum/refinery[f]	crude oil	2.5	40;10	12;20	12;7	2;360	—
Electricity/coal combustion[g]	bituminous coal, 2% S	20	200–400	very low	very low	100–500	
Electricity/IGCC at Cool Water[h]	various coals	2–4	8–34	—	32–43	2	—

Sources: Adapted from reports published from 1978 to 1983 by Pace Co., US Office of Technology Assessment, Argonne National Laboratory, US DOE, and SRI International, except as noted below. See Ref. 7, Table 49 for full citations.

[a] Based on Exxon Donor Solvent and Solvent Refined Coal II Processes.
[b] Based on various gasifier technologies. The upper values refer to low-temperature Lurgi gasifiers.
[c] From a German study cited in Ref. 32 which did not specify the coal.
[d] Ref. 33.
[e] Emission rates established by air quality permit for Great Plains SNG plant. Actual SO_X emissions in 1986 were 360 gm/million Btu. "No limit" means that no emission limits were established in the permit.
[f] Ref. 34. First figure is for fluid catalytic cracking units with controls, second is for moving-bed catalytic cracking. We assume 0.05 million Btu of residual fuel oil per million Btu of output for process heat, a crude oil sulfur content of 2% by weight and energy content of 140,000 Btu/gallon. HC emissions includes fugitive emissions (12 g/million Btu).
[g] Based on New Source Performance Standards for new power plants.
[h] Integrated gasification combined-cycle power plant. From Ref. 35.

technically and financially. Because of the physical concentration of coal and oil shale deposits and the resulting economies of scale in feedstock collection and conversion, the plants require huge fixed investments, more than all but the largest multinational energy companies can afford. The return on these investments is very uncertain: the plants take years to build, use unproven technology, and produce expensive fuels that could be underpriced by gasoline and diesel fuels. These technical and financial risks make it unlikely that any initial commercial-scale plants would be built without extraordinary government support or risk-sharing.

Without government intervention, many years will elapse from the time synthetic fuels may first be price competitive to the time a sizable industry is operational. To this point only one first-generation oil shale plant has been built. Initially completed in 1984 by Union Oil, it still has not reached full production because of various technical problems. Not a single demonstration-scale coal liquids plant has been built since World War II apart from the South African plants, which use an inefficient Fischer-Tropsch process. Considering that production costs will not be brought into the $30-40 per barrel range until about a third-generation plant is built, that it takes 5 to 8 years to build a plant, and that some period of learning is needed after one plant is built and before the next generation plant is designed, we estimate that, without government intervention, the lag time due to risk and technological development could be 30 years after the time the market first signals that these investments are likely to be profitable.

Opportunities for Petroleumlike Fuels

Selection of this path would reflect a conservative strategy to protect sunk investments in petroleum-fuel infrastructure and to minimize disruption of activities of energy and automotive companies. Given a choice, these companies would tend to favor this path (40). Those who support this path would either have a stake in the status quo or less interest in environmental quality.

For this path to proceed, however, government would need to play a major role in reducing risk—using price, purchase, and loan guarantees like those provided by the US Synthetic Fuels Corporation (SFC) in the early 1980s. Massive government support would be needed to initiate this path, perhaps more than with other fuel options, because no niches exist either on the production or market side that would tempt private-sector initiatives.

On the production-side, for example, alcohol and gaseous fuels and electricity can be produced from biomass residues and wastes and unwanted associated natural gas; on the end-use side, biomass fuels would be attractive in isolated rural settings, CNG in centrally fueled fleet vehicles that are highly utilized (so that the low fuel costs repay the higher vehicle costs), and electric vehicles in areas with severe air pollution. On the other hand, these petroleumlike fuels do not benefit from any exceptionally inexpensive sources of feedstock, nor any end-use markets where some attribute(s) of these petroleumlike fuels would be highly valued—because the fuels would be virtually identical to preexisting petroleum fuels.

The SFC was a failure, its funding withdrawn by the United States Congress in 1985. This failure provides insight into the obstacles faced by a petroleumlike mineral fuels path. One important reason it failed was the fall in oil prices, but oil prices also fell in Brazil, Canada, South Africa, and New Zealand, without causing those countries to abandon their alternative fuel programs. Another factor, specific to the politics of the time, was that the SFC became politicized and burdened by incompetent appointed leadership (41). A more fundamental problem, generalizable to future support for petroleumlike fuels from oil and coal, is that the recipients of SFC subsidies were large energy companies. This last factor was crucial. It meant that the program's political constituency was narrow, and that the principal beneficiary was a group looked upon with great suspicion by the United States Congress, which mounted numerous efforts in the 1970s to dismember "big-business" oil companies.

Finally, synfuels projects ran into strong and continuing opposition from environmentalists. This opposition increased investment and operating costs, increased construction times, and reduced support in Congress.

In conclusion, this path is attractive to the petroleum and automotive industries and those concerned about national energy security. But two factors undermine its viability: opposition by environmental groups and the likely reluctance of government to subsidize large energy companies.

BIOMASS FUELS

Biological matter (biomass) can be a feedstock for the production of a range of liquid and gaseous fuels. Although biomass has been used to manufacture transportation fuels since the 19th century, major biomass transportation fuel activities were not initiated until the late 1970s, when Brazil and the United States fermented sugar cane and corn, respectively, into ethanol. About 184,000 barrels per day of ethanol were produced as a transportation fuel in Brazil in 1987 (42) and about 50,000 barrels per day in the United States. More than 90% of all Brazilian cars have been designed to operate strictly on ethanol since about 1983. In the United States, the ethanol is mixed in a 10/90 blend with gasoline so that it can be burned in conventional unmodified gasoline-powered vehicles. Various developing countries have experimented with biomass ethanol, but with much less success.

Biomass fuels are attractive because the feedstocks are renewable and domestically available, and therefore could permanently displace imported petroleum. The use of biofuels in transportation results in no net CO_2 produced (because the CO_2 is in effect being recycled), provided that the energy used in the manufacture of the biofuels—by farm machinery and fuel conversion facilities, in the making of fertilizers, and so on—also does not produce CO_2. On the other hand, the potential supply of biomass is limited, production of biofuels is costly, and environmental impacts can be considerable.

Feedstocks and Fuel Production

While virtually all current biomass transportation fuel activities involve the fermentation of crops and food wastes containing large amounts of starch and sugar, the more promising option is the use of lignocellulosic material, especially wood pulp. Lignocellulosic material is more abundant and generally less expensive than starch and sugar crops. The most promising processes for converting lignocellulose (hereafter referred to simply as cellulose) into high-quality transportation fuels are thermochemical conversion into methanol or hydrolytic conversion into ethanol; less promising are pyrolysis processes that convert biomass into low-grade petroleumlike liquids. Biomass may also be thermochemically gasified and then cleaned and upgraded into a clean high-Btu gas. The production cost and environmental impacts are similar to those of methanol production and the end-use attributes are identical to those of compressed natural gas (CNG). For simplicity, this latter option is not explicitly treated here.

Unlike other alternative energy options, biomass could not or, more accurately, should not be depended on as the sole transportation energy source, except perhaps in land-rich Brazil. In the United States, for instance, even if all the wood pulp now harvested by the paper and wood products industries, including logging and mill residues, and all the harvested corn and wheat were used to make biomass fuels, there would not be enough to satisfy current United States transportation fuel demand. (A biomass fuels industry using dedicated biomass energy plantations could increase current yields of wood pulp on forest land tenfold or more, but total production would still be dwarfed by transportation energy demand unless a large proportion of forest land were diverted to biomass energy plantations.)

An estimate of biomass fuel potential in the United States, assuming no major disruption of existing agricultural and silvicultural markets and land management activities, is provided in Table 2. As indicated in that table, up to about 1.8 million oil-equivalent barrels per day of fuel could be produced in the United States; more than half this energy is contributed by wood plantations. The remainder comes from wood and crop residues, grass crops, peat, and municipal solid waste.

A possible attraction of an expanded biomass fuels industry would be the dispersed and small-scale nature of biomass production and conversion activ-

Table 2 Potential US methanol production from biomass[a]

Feedstock	Potential annual production (thousands of barrels per day)[b]
Crop residues	500
Forage (grass) crops	650–1300
Wood resources	250–2000[c]
Municipal solid waste	50–250
Peat	0–100[d]
Total	1450–3550

Source: Adapted from Refs. 43–48.

[a] Most of these estimates were developed in the late 1970s and are highly optimistic. Although they were intended to be estimates of production potential for the period 1990 to 2000, a more realistic view is to treat the estimates as ultimate production potential to be realized sometime in the next century.

[b] Projections adjusted by conservatively estimating that 100 gallons are produced from each dry ton of biomass. If the feedstock is not used as the energy source to power the process plant, then the yield would increase by about 20 gallons per ton.

[c] Lower quantity refers to wood residues; larger quantity refers to silvicultural energy farms.

[d] No published projections available: these are authors' best guess.

ities. Biomass cultivation would be dispersed over large areas of land, because even the most intensively managed experimental farms, such as short-rotation silvicultural farms, yield only enough per year to produce about 40 barrels per acre (100 per hectare). This yield estimate is based on the assumption that about 20% of the biomass is used as energy in the processing plant and that, unlike for corn farming, relatively small amounts of energy are used in cultivation and transport. Average yields would be much smaller. Fuel production plants would also be dispersed over a wide area because of the high cost of transporting the dispersed biomass to production plants; the production plants would be relatively small and located near the harvest locations. Because of trade-offs between economies of scale in production and diseconomies of scale in feedstock collection (49), most plants would be much smaller than typical oil refineries or mineral fuel plants. Thus biomass fuels would be favored by those seeking decentralized energy investments, for instance those advocating a "soft" energy path.

Costs

Biomass-derived alcohols now are much more expensive than gasoline on an energy-equivalent basis, and are expected to remain so for the foreseeable future. Ethanol fuel in Brazil is about as costly to manufacture, on an energy basis, as gasoline produced from oil priced at $30–35 per barrel (50, 51); in the United States the cost is substantially higher (52).

Table 3 Estimated plant-gate production cost of transportation fuels (1986 $)

Feedstock	Fuel	$ per physical gallon	$ per million Btu
Petroleum ($15/bbl)	Gasoline	0.40–0.50	3.70– 5.00
Petroleum ($30/bbl)	Gasoline	0.80–1.00	7.00– 9.00
Petroleum ($60/bbl)	Gasoline	1.50–2.00	13.00–17.40
Natural gas (US)	Methanol	0.50–0.80	9.10–14.50
Remote natural gas	Methanol	0.40–0.60	7.30–14.50
Coal	Methanol	0.80–1.30	14.60–23.60
Coal	M-gasoline	2.00–3.25	16.30–28.30
Coal	Gasoline	1.80–2.60	15.70–22.60
Oil shale	Diesel	1.40–2.00	10.40–14.80
Wood	Methanol/ethanol	0.80–1.35	14.50–24.50
Corn	Ethanol	1.20–1.70	15.80–22.40
Sugar cane (Brazil)	Ethanol	0.80–1.10	10.50–14.40
Water (and solar electricity)	Hydrogen	—	20.00–70.00

Source: Standardized cost estimates for biomass fuels are presented in Ref. 53, and for mineral and biomass fuels in Ref. 54 (which in turn are based on Refs. 55, 56). Other standardized estimates of mineral fuel production costs are in Refs. 57–59. For review of estimates of ethanol costs in Brazil see Ref. 60 and for hydrogen see Ref. 61.

The cost of converting cellulose to ethanol or methanol cannot be specified as precisely since the technology has not been commercialized, but a reasonable estimate would be a cost similar to that of converting coal to methanol, ultimately $0.80–1.00 per gallon (Table 3). This plant-gate production cost is equivalent to a retail gasoline price of more than $2 per gallon, since methanol contains only half the energy per unit volume as gasoline. Correspondingly, the distribution and retailing cost per gasoline-equivalent gallon is at least twice that of gasoline. Recent evidence indicates that improvements in cellulose conversion technology may lower production costs (62), but even so, biomass transportation fuels will not be competitive in price with gasoline until oil prices are at least $30 to $40 per barrel.

Ethanol fuel activities are thriving in the United States and Brazil, despite high production costs, because of the political and economic strength of the agricultural and food processing industries. Blends containing 10% ethanol and 90% gasoline accounted for about 7% of all gasoline sales in the United States in 1988. Ethanol exists in the United States only because of generous federal subsidies of $0.60 per ethanol gallon (equivalent to $0.90 per gallon of gasoline on an energy basis) and additional subsidies from many state governments. These huge subsidies benefit primarily ethanol manufacturers, but also gasohol blenders and corn farmers.

Environmental Impacts

The introduction of biomass fuels has the potential to nearly eliminate greenhouse gas contributions by the transportation sector and to provide small improvements in air quality. On the negative side, increased biomass fuel production may increase soil erosion.

GREENHOUSE GASES The combustion of biomass fuels would generate large amounts of carbon dioxide, but these emissions would be roughly offset by the carbon dioxide taken out of the air by the biomass plants via photosynthesis. As long as fossil fuels are not used for process heat in the feedstock processing plant and in other steps of production and distribution, biomass fuels would be a highly attractive strategy for reducing global warming.[5]

Table 4 shows emissions of greenhouse gases from a wide variety of alternative transportation fuels under the assumption that each fuel supplies the entire US highway fleet. Emissions of CO_2, CH_4, and N_2O from the entire chain of activities from the extraction of feedstock to end-use combustion are considered. Emissions of CH_4 and N_2O have been converted to the amount of CO_2 having the equivalent warming effect;[6] the percentage changes shown in Table 4 are CO_2 equivalents. As shown, the only effective long-term options for eliminating emissions of greenhouse gases from the transportation sector are the use of biomass fuels, and hydrogen and electricity made with nonfossil power.

AIR AND WATER QUALITY Biomass fuels will do little to improve air and water quality. The end-use fuels—ethanol, methanol, synthetic natural gas, or perhaps some petroleumlike liquid—will produce slightly fewer air pollutant emissions than gasoline and diesel fuel (as discussed below), but the biomass conversion process tends to be dirty, producing large quantities of air pollutants (see Tables 1 and 5). While control technologies can be installed on biomass production plants, they are expensive and, because of the large number of small plants, it may be difficult to regulate and enforce emission restrictions. Biomass fuel activities would also generate large amounts of

[5]There are two qualifications. First, there is a one-time increment of CO_2 if forests are cleared to plant less carbon-intensive fuel crops. Second, this ignores the relatively small amount of secondary greenhouse gases (CH_4, N_2O, and ozone precursors) emitted from vehicles.

[6]We have converted CH_4 and N_2O mass emissions from vehicles into the mass amount of CO_2 emissions with the same temperature effect, where "same temperature effect" is defined as the same number of degree-years over a given time period (we have chosen 125 years); and one degree-year is defined as an increased surface temperature of 1°C for one year. In order to convert CH_4 emissions into CO_2 emissions having the equivalent temperature effect, one needs to know for both gases the relationship between: (*a*) equilibrium surface temperature and equilibrium atmospheric concentration of the gas; and (*b*) the increase in yearly emissions of the gas and the increase in the equilibrium atmospheric concentration (note that many "conversion factors" given in the literature ignore the second step, and hence cannot be applied to emissions). These relationships are derived in Ref. 14. The result is that N_2O mass emissions multiplied by 175, and CH_4 emissions by 11.6, produce the mass of CO_2 emissions with the same temperature effect.

Table 4 Emissions per mile of a composite measure[a] of greenhouse gases, relative to petroleum-powered internal combustion engines[b]

Fuel feedstock	Percent change
Electric vehicles/nonfossil electricity	−100
Hydrogen/water-nonfossil electrolysis[c]	−100
CNG/LNG/MeOH/biomass[d]	−100
CNG/natural gas	− 19
Electric vehicles/NG plants	− 16
LNG/natural gas	− 15
Methanol/natural gas	− 3
Electric vehicles/current power mix	− 1
Gasoline and diesel/crude oil	—
Electric vehicles/new coal plant	+ 26
Hydride/coal	+100
Liquid hydrogen/coal	+143

Source: Ref. 14.

[a] The composite greenhouse gas is actual mass emissions of CO_2 plus CH_4 and N_2O emissions converted to mass amount of CO_2 emissions with the same temperature effect, as explained in the text here and in Ref. 14.

[b] The analysis considered emissions of CH_4, N_2O, and CO_2 from the production and transportation of the primary resource (coal, natural gas, or crude oil), conversion of the primary resource to transportation energy (e.g. natural gas to methanol, or coal to electricity for battery-powered vehicles), distribution of the fuel to retail outlets, and combustion of the fuel in engines, except as noted. N_2O emissions from vehicle engines were not included (the preliminary estimate in Ref. 14 indicates that they are relatively unimportant). Emissions of ozone (O_3) precursors, CFCs from air conditioning systems, and H_2O were not considered (available data and models do not allow estimation of the greenhouse effect of emissions of ozone precursors; CFC emissions are independent of fuel-use; and H_2O emissions from fossil fuel use worldwide are a negligible percentage of global evaporation).

[c] Hydrogen vehicles emit N_2O and H_2O; as noted above, H_2O emissions from the entire fuel cycle, and N_2O emissions from vehicles, were ignored.

[d] CNG and methanol vehicles emit N_2O, H_2O, ozone precursors, and CH_4. As noted above, vehicular emissions of N_2O, and all emissions of H_2O and ozone precursors, were ignored. The carbon in CH_4 emissions from biofuel-vehicles originally comes from atmospheric CO_2, but since CH_4 is a more effective greenhouse gas than CO_2 per molecule of emissions, the transformation of CO_2 to CH_4, ignored here, results in a slight increase in effective emissions of greenhouse gases.

water effluents (69, 70) and solid waste (see Table 6). On the other hand, pollution generated during fuel production will tend to be in rural areas where pollution is less of a health problem (though air quality rules in the United States encourage prevention of significant deterioration, thereby possibly hindering the establishment of these plants in rural areas).

Table 5 Percentage change in emissions from alternative-fuel vehicles, relative to gasoline[a]

Fuel	RHC	CO	NO_X	O_3	SO_X	PM
Methanol (w/catalyst)	−50	−40	0	−50	− 100	?
CNG, LNG (w/catalyst)	−60	−95	+25	−60	− 100?[b]	?
Hydrogen (no catalyst)	−95	−99	−60	−95	− 100	?
Electricity (year 2000 mix[c])	−99	−98	+3	?	+2100	+3400
Electricity (nonfossil)	−100	−100	−100	−100	− 100	−100

Sources: Refs. 61, 63, 64. These are rough estimates only, assuming advanced technology, single-fuel cars, and engine operation with excess air (i.e. lean; lean operation lowers CO and RHC emissions, because more air is available for complete combustion). Does not include evaporative emissions from vehicle or vehicle refueling, or emissions from petroleum refining and fuel manufacture, except in the case of electric vehicles using the projected year 2000 mix.

RHCs = reactive hydrocarbons (total hydrocarbon emissions less methane, which is nonreactive and hence does not contribute to ozone formation). PM = particulate matter.

[a] Ethanol fuel is not included because of minimal experience and testing with controlled vehicles. In general, ethanol-powered vehicles will have similar emissions to those from methanol-powered vehicles. One difference is in aldehyde emissions, which may lead to the increased formation of another oxidant, peroxyacetyl nitrate (PAN) with ethanol (66).

[b] Assumes that natural gas and SNG do not contain sulfur, which may not always be true.

[c] We first estimated average g/mile emissions in the year 2000 from a fleet of internal combustion engine vehicles (of varying age classes) that could be replaced by electric vehicles. We included evaporative emissions and emissions from vehicle refueling and bulk gasoline terminals. The fleet consisted of 80% vans (20 mpg) and 20% passenger cars (30 mpg), and was assumed to meet the most stringent feasible future emission standards, as determined by Sierra Research (67). We then estimated the energy consumption of the comparable electric vehicle fleet, and converted emissions from power plants to grams of pollutant per mile of vehicle travel. We assumed that 54% of the electric vehicle recharging energy will come from coal steam plants, 10% from gas boilers, and the rest from nonfossil baseload plants (based on EIA projections (68) for the year 2000). Oil and gas combined-cycle power plants were ignored because they are minor inputs to electricity generation nationally, and are used primarily for peaking. We assumed that 50% of coal power plants will have scrubbers for SO_X (95% reduction) and baghouses for particulates (99% reduction); that 30% of coal and NG power plants will have selective catalytic NO_X reduction (80% reduction), and that 20% will have flue gas recirculation (80% reduction) or thermal de-NO_X (70% reduction).

EROSION The most troublesome environmental impact will be soil erosion. Although there is considerable controversy over the extent of soil erosion, a conservative estimate is that half or more of US cropland is suffering a net loss of soil. The Soil Conservation Service estimates that average erosion on United States cropland due only to rainfall is 4.77 tons per acre per year (75), while others estimate total annual erosion, including wind erosion, to be as high as 9 tons (76). Since only about 1.5 (77) to 5 tons of soil form per acre-year (78), soil formation cannot keep pace with these losses.

New land brought into cultivation to produce biomass fuels will be at least as prone to erosion as existing land (79). If marginal lands are brought into cultivation without very careful soil management, comparatively large amounts of soil will be lost. In general, proper soil management can greatly reduce erosion, but in practice it is rare, because of ignorance, reluctance to change, and unwillingness to invest in techniques with long-term payoffs. Consequently, extensive cultivation of biofuels is likely to be economically and ecologically damaging.

Table 6 Solid waste from energy production, kilograms per million Btu

Conversion process	Ash	Other[a]	Total (excluding coal preparation refuse)	Coal preparation refuse
Corn fermentation (ethanol)	7.4–22	—	14–38	
Wood gasification (methanol)	2.5–6	1.5	4–9	
Lignite gasification (methanol)	8.0–9.6	—	9–13	0.86[b]
Coal gasification (methanol)	5.8–6.7	—	7–11	0.86[b]
Cellulose hydrolysis (ethanol)		25–257	25–257	
Coal-fired power plant (electricity)[c]	4.8–24	5.0–15.4	10–40	0.86[b]
Direct coal liquefaction (liquids)	8–15	—	9–25	0.86[b]
Oil shale pyrolysis (liquids)[d]	0	145–390	145–390	

Sources: Adapted from Refs. 71–74.
[a] Other = scrubber waste, wastewater sludge, dust, spent shale. Sulfur and other marketable products not included.
[b] Lower value refers to case of thick coal seams. Not included in total column.
[c] Range in values represents two cases based on equivalent quantity of coal and equivalent quantity of output energy, as well as sensitivity to other factors, such as ash content of coal.
[d] Lower value is for modified in-situ process and upper value for surface retort processes.

Opportunities for Biomass

A biomass fuel pathway differs from others mostly in its spatial dispersion of activities and the large number of economic participants. A major biomass transportation fuel initiative in the United States and most other countries, not relying on starch or sugar crops as is the current fashion, would involve many growers, harvesters, and feedstock processors. It would be more decentralized than any other set of options. There would be many small market niche opportunities—for instance, the use of food processing wastes, forest residues, and culled fruits—and it would tend to depend on entrepreneurial initiative. Because of the dispersed and regional nature of biomass fuel activities, government support in the United States would be more likely to come from local (and state) governments than would be the case with other transportation energy paths.

The major attractions of a biomass fuel path are renewability and domestic availability of the feedstock material, the potential for virtually eliminating greenhouse gases, and perhaps the decentralized nature of investments and activities. Thus, a biomass fuel path most likely would take root if energy security and the greenhouse effect become important concerns and anti–big business attitudes gain strength. Unless vehicular fuel-efficiency improves severalfold, however, biomass fuels cannot be expected to satisfy a large share of US transportation fuel demand (nor of most other countries). The optimistic production estimate presented in Table 2 of 0.7–1.8 million barrels per day of oil-equivalent biomass methanol represents only a fraction of current US transportation fuel demand (10 million barrels per day). Above that 1.8 million barrels per day level, costs and soil erosion would increase significantly.

Factors arrayed against ethanol and methanol biofuels are their currently high cost, the need for careful soil management and, as addressed later, their incompatibility with current vehicles and fuel distribution systems.

The prospects for biomass fuels are being pushed further into the future in the United States by the unwillingness of the state and federal governments to fund R&D on higher-yield, lower-cost biomass crops and improved biomass conversion technologies. [The Reagan administration requested only $12.2 million dollars for US Department of Energy research on biomass energy systems for fiscal year 1987 (80).] In particular, thermochemical gasification and conversion processes need considerable development, and are probably underfunded relative to their potential (81). The virtual absence of government R&D sends a (mistaken) message to the forestry, farm machinery, and agricultural industries that biomass fuels have no future.

METHANOL FROM NATURAL GAS AND COAL

Background

Methanol is now the most widely promoted alternative transportation fuel in the United States (82–85), but this popularity is very recent. Throughout the 1970s and early 1980s, the preferred option for replacing petroleum was petroleumlike "synthetic fuels" made from coal and oil shale. In the 1970s government and industry studies consistently rated methanol below synthetic fuels (86–88). Methanol was considered an inferior option partly because it was thought that natural gas was in short supply, and thus that methanol would have to be made from coal. The main argument against methanol, though, was that it was too different from petroleum: it would require new or modified distribution systems and vehicles, whereas synthetic crude could simply be added to natural crudes at refineries, helping oil companies maintain the usefulness of present investments and insulating consumers from change (89).

In the early 1980s, perceptions began to shift, motivated by three new insights: first, the cost of manufacturing petroleumlike fuels was greater than had been anticipated; second, natural gas was more abundant than had been thought; third, petroleumlike synthetic fuels did not help reduce persistent urban air pollution. The cost problem became salient as world petroleum prices stabilized and then dropped in the 1980s, and as feasibility studies by project sponsors for the US Synthetic Fuels Corporation began to show that the cost of producing refined shale oil and pretroleumlike liquids from coal would be \$60–100 per oil-equivalent barrel in first- and second-generation plants (90).

At the same time, it was becoming evident that much more natural gas (NG) existed than had been recognized. Although estimates of domestic and worldwide NG reserves began to be revised sharply upward in 1979, this revision was not widely noted until several years later. The changed perception of NG availability was crucial, because methanol can be manufactured much more cheaply and cleanly from NG than from coal—and also much more cheaply than any transportation fuel made from coal, oil shale, or biomass (see Table 3). The combination of higher-than-expected costs for synfuels, and greater-than-expected supplies of gas, the cheapest methanol feedstock, made methanol look more attractive.

The potential air-pollution benefits of methanol further confirmed methanol's attractiveness. These benefits first gained attention in the early 1980s in California. A landmark study prepared for the California Energy Commission (CEC) (91) concluded that, given the state's high priority on reducing air pollution, the most attractive use of coal, then thought to be the most promising future source of portable fuel, was to convert it to methanol for the transportation and electric utility sectors. Although this study was not widely circulated, it laid the basis for the CEC's aggressive organizational commitment to methanol. The CEC has proven to be the most influential advocate of methanol through the 1980s, the major justification being air quality (92, 93). By 1985 air quality had become a primary issue nationwide, and interest in methanol began to surge.

Feedstocks

At present, economic and environmental considerations favor natural gas over coal and biomass as a methanol feedstock. The production of methanol from natural gas is much less expensive and produces much less pollution than coal-methanol processes; emissions from NG-to-methanol plants are similar to those of petroleum refineries, while emissions from coal-to-methanol plants are much greater (see Table 1). The least expensive natural gas is so-called "remote natural gas" (RNG), gas in foreign (usually Third World) countries remote from readily accessible markets and priced at about \$1.00 per million Btu or less. Initially, methanol would be made in these low-cost, gas-rich countries and imported to the United States. Methanol imports would do little to enhance US energy security, and in fact could weaken it because, on balance, foreign-made methanol would be replacing high-cost, domestic petroleum, and foreign methanol suppliers might be no more secure than petroleum exporters. Methanol use would probably also increase US payments to exporters for energy, which would add to the trade deficit (94). However, as demand for methanol and for other uses of RNG grows, remote gas will become more valuable, and its price will rise. Eventually, the price will be high enough to make domestic gas, and then coal and biomass, competitive as feedstocks.

Methanol made from natural gas could supplant petroleum fuels for several decades; the precise duration of a natural gas–to-methanol era would depend on natural gas use in other sectors, the number of vehicles switched to methanol, and the success of natural gas exploration and development efforts.

Environmental Impacts

Methanol from natural gas is not a permanently sustainable transportation option, nor is it dramatically cleaner than gasoline. It may, however, be enough cleaner to help cities in air quality nonattainment areas make small progress toward meeting national air quality standards. Methanol also will be much cleaner than diesel fuel, and may be the best strategy for meeting the stringent 1991/94 North American emission standards for heavy-duty engines (95).

The most critical urban air pollution problem in the United States is ozone; 69 metropolitan regions violated ozone standards in 1987. Unburned methanol emissions from methanol vehicles are generally less reactive than the hydrocarbon (HC) emissions from gasoline vehicles, and thus tend to produce less ozone. This promise of reduced ozone is the primary attraction of methanol vehicles; they are likely to have few other environmental benefits. Methanol may produce less CO or NO_x (but not both) than gasoline vehicles (Table 5); the result will depend on the air-fuel ratio, the type of catalyst materials used in control devices, and state of cold-start technology. Methanol production from natural gas is probably slightly cleaner than petroleum refining, but the difference is not very important because petroleum refineries are already relatively clean. And methanol from natural gas would not reduce emissions of greenhouse gases from the transportation sector, compared to gasoline and diesel-fuel use. Methanol from coal would cause a large increase in greenhouse gas emissions (Table 4).

The magnitude of ozone reduction possible with methanol substitution is uncertain. Many studies have been conducted, but the results are controversial and difficult to generalize. In the mid-1980s, several researchers concluded that the use of methanol in all highway vehicles would reduce peak one-day ozone concentrations in urban areas by 10 to 30% (96–98). In Los Angeles (and elsewhere), however, the worst smog episodes occur as pollution builds up over several days; in 1986 smog chamber experiments indicated that methanol use may not be as beneficial in multiday ozone episodes (99). Subsequent modeling studies at Carnegie-Mellon University found that in the Los Angeles area, the use of 85% methanol/15% gasoline (the most likely combination) in all mobile sources (vehicles) except motorcycles and planes would result in only a 6% reduction in peak ozone levels (100).

If 100% methanol (M100) were used in advanced technology engines with extremely low formaldehyde emissions, ozone would be reduced 9%, compared to an advanced-technology gasoline engine. The 9% reduction with advanced-technology M100 represents 43% of the maximum ozone reduction attainable from motor vehicles; that is, if all vehicle emissions were eliminated, ozone would be reduced 21% (101). A subsequent study questions these findings, arguing that methanol vehicles would emit more NO_x than gasoline vehicles, and more than is assumed by the Carnegie-Mellon researchers, thereby causing ozone levels to increase (102). In any case, the greatest potential ozone reductions with methanol require the use of M100 and very low formaldehyde emissions, two conditions that may not be attainable. We estimate that the substitution of methanol for gasoline in all motor vehicles would result in a maximum reduction in peak ozone levels of 0 to 10% in multiday smog episodes.

In contrast to the uncertainties surrounding the environmental benefits of substituting methanol for gasoline, there are several clear environmental advantages to using pure methanol in heavy-duty engines. Methanol produces essentially no particulates, smoke, SO_x, or unregulated pollutants. In addition, a methanol engine with an oxidation catalyst produces very little CO, HCs, and formaldehyde (103, 104).

In summary, methanol use would not reduce greenhouse gas emissions, but would provide some air-quality benefits when used in diesel engines; it may lead to a minor reduction in either NO_x or CO emissions in spark-ignition engines (and perhaps an increase in the other), and has the potential for achieving a part of the maximum ozone reduction attainable through changes in the transport sector. But the magnitude of these potential improvements is modest.

Cost

Methanol is more expensive than gasoline on an energy-equivalent basis, and will continue to be so for the foreseeable future. The most recent estimates are that very small amounts of methanol can be delivered to the United States for as little as $0.20–$0.30 per gallon if the remote natural gas (RNG) feedstock is virtually free and sunk costs in the methanol plant are ignored (105). A more reasonable estimate, based on sustainable rate-of-return conditions and assuming competition for the RNG feedstock—including both domestic uses and other exporting possibilities—is $0.40 to $0.60 per gallon (equivalent on an energy basis to $0.80 to 1.20 per gasoline gallon) (106). Methanol could be produced from coal in the United States for around $1.00 per gallon (107). When transportation, storage, and retailing costs are considered, methanol from RNG would not be competitive with gasoline until gasoline sold for $1.10–1.70 per gallon, including taxes (and allowing for the fact that methanol is about 10–20% more efficient than gasoline in internal combustion engines). Methanol from coal would not be competitive until gasoline sold for at least $2 per gallon.

Opportunities for Methanol

An important first use of methanol (and natural gas) fuels in the United States may be in heavy-duty diesel engines. New emission standards requiring sharp reductions in particulate and NO_x emissions from heavy-duty diesel vehicles take effect in the United States and Canada in 1994 (1991 for transit buses). Meeting the standards by applying control technology to diesel combustion will be difficult: the vehicle capital costs may be less with a methanol (or natural gas) engine. although the methanol fuel costs would be greater. Several heavy-duty engine manufacturers are developing methanol (and natural gas) engines.

However. diesel-powered trucks consume only about 2 of the 15 quadrillion Btus of energy used annually on the highways in the United States (108) (although the proportion is increasing). If methanol is to replace a significant amount of petroleum transportation fuel. and have a discernible impact on air quality. it must penetrate the market for light-duty (gasoline) vehicle fuels. A strategy to introduce methanol in this market must address the high cost of methanol fuel compared to gasoline and the large initial costs both for manufacturing methanol fuel and methanol vehicles. and for establishing a national methanol distribution network for light-duty vehicles. The large initial costs and uncertain market create a need for cooperation between fuel producers and vehicle manufacturers.

The problem of fuel cost is straightforward. Consumers will not use methanol. nor manufacturers make dedicated methanol vehicles. unless methanol use is mandated or subsidized to bring its cost below that of premium gasoline. Government perhaps could justify subsidies or mandates on air quality grounds. but not. as noted above, on global-warming or energy-security grounds.

The problem of start-up costs is more complicated. Because of large start-up costs, manufacturers will not invest in the manufacture of methanol vehicles if the methanol fuel is not available, and fuel producers will not invest in the production and distribution of methanol, even when it is cheaper than gasoline, unless there are vehicles that can burn it. To use methanol, motor vehicles must be modified; the cost of building these modified vehicles will be large initially, since retooling and R&D costs must be spread over a relatively small number of vehicles (although at full production the cost of a methanol-powered vehicle is expected to be about the same as the cost of a comparable gasoline-powered vehicle). Similarly, establishing a methanol fuel delivery infrastructure will be fairly expensive. The minimum cost approach for a large scale effort would be to market the fuel only in and near ports with ocean access, obviating the need to modify the existing oil product pipeline network or to build an entirely new pipeline network. (Since methanol will be imported initially, a port-based distribution system will be adequate at first.) DOE estimates that the capital cost of building a national methanol distribution system, using only waterborne and truck transport, with methanol marketed only within 100 miles of major river and ocean ports (reaching about 75% of the United States), would be $13 billion (109).

The "chicken-and-egg" dilemma created by these large start-up costs could be resolved by coordinating vehicle manufacture, fuel distribution, and fuel production. Such coordination probably would be arranged by state or federal government. Incentives, not necessarily financial, would need to be offered to vehicle manufacturers to induce them to manufacture and market methanol vehicles, and financial subsidies would need to be offered to retail fuel stations and consumers, at least initially, to overcome the price disadvantage of methanol. (We note, however, that what government invokes, it can revoke, and that even with incentives and subsidies, the private sector runs some risk.) Relaxation of vehicle fuel-efficiency standards for manufacturers that market methanol vehicles, as provided for in the Alternative Motor Fuels Act of 1988 (PL 100-494), might be sufficient to induce manufacturers to produce methanol (or other nonpetroleum) vehicles. Retail fuel suppliers will require more direct subsidies, such as the $50,000 capital grants offered by the Canadian government to retail fuel stations to install facilities for compressed natural gas (CNG) and per-gallon subsidies provided by the California Energy Commission to methanol fuel suppliers. Ultimately, consumers would have to be subsidized to convince them to buy methanol, since methanol will cost more than gasoline until oil prices reach $30 per barrel or more.

In summary, the transition to methanol would be associated with a slightly stronger environmental ethic and a more activist government than would the petroleumlike fuels path. A long-lasting national transition to methanol will occur, however, only if reducing energy imports, slowing the greenhouse effect, and significantly improving air quality are not high priorities. Methanol offers modest environmental benefits at modest cost.

METHANE FUELS

Feedstocks

Natural gas, composed mostly of methane, need not be made into methanol to be used as a transportation fuel—it can be stored onboard a vehicle in compressed (CNG) or liquefied (LNG) form, and burned in the engine as a gas. Later, as the availability of natural gas diminishes and its cost increases, a substitute ("synthetic") natural gas (SNG) could be produced from coal (or perhaps biomass). The principal advantage of this methane path is lower fuel cost to the end user during the natural gas era, because, as explained below, it is cheaper to compress or liquefy natural gas than to convert it to methanol. Methane could remain as an important or even dominant fuel after natural gas supplies become scarce by converting coal to SNG (mostly methane); the cost for converting coal to methane would be about the same as converting it to methanol (Table 3). The principal disadvantages of the CNG/LNG path are those associated with storing gaseous fuels in vehicles and establishing a network of retail fuel outlets.

In the foreseeable future, natural gas transportation fuels for the North American market will be supplied from North America. North American natural gas would be shipped via pipeline to fuel stations, where it would be compressed or liquefied for use by highway vehicles. (It also would be possible to liquefy natural gas in large quantities at central facilities and transport the LNG by truck to service stations.)

Later, if and when methane fuels gain prominence, remote natural gas (gas in areas not connected by pipeline to the United States) would be liquefied and then transported in large LNG tankers. Once the LNG reached the United States, two distribution routes would be possible. The LNG could be regasified, placed in the pipeline network, distributed to fuel stations, and then compressed (or perhaps liquefied again) for use by motor vehicles. Alternatively, the LNG could be off-loaded to central LNG storage facilities and then trucked to retail stations, for use by LNG vehicles.

At present, regasified LNG from RNG is not competitive with domestic NG, because the cost of liquefaction and cryogenic transportation is greater than the cost savings from using the cheaper RNG feedstock.[7] Most LNG terminals in the United States are idle, and will remain so until the cost gap between domestic gas and RNG increases. Consequently, for economic reasons it is not likely that RNG would be used to supply CNG fuel in the foreseeable future.

[7]RNG feedstock may cost as little as $0.50 per million Btu, whereas domestic gas costs about $2 per million Btu at the wellhead (110), but the landed cost of RNG in the United States, including liquefaction, transport, and regasification, is about $3–4 per million Btu (111, 112)—much more than the average wellhead cost of domestic gas, and more than the cost of domestic gas delivered to industry and utilities (under $3 per million Btu).

If LNG were demanded as LNG (that is, used directly as a liquid, and not regasified), it might then be economical to import LNG from RNG rather than make LNG from domestic gas: in this case, the cost of liquefying RNG would not be a disadvantage compared to using domestic gas, because the domestic gas would have to be liquefied also. RNG, then, might be an economical fuel for LNGVs, especially in coastal cities far from major US gas fields. However, LNG terminal capacity in the United States is relatively small (less than 1 trillion cubic feet), and would have to be expanded considerably to handle significant amounts of LNG. Such an expansion might be opposed by the public, which in the past has been concerned about the safety of LNG terminal operations.

In sum, RNG will not be a major feedstock for NG transportation fuels in the United States, unless the cost advantage of RNG feedstock increases, or there is large demand for LNG by LNGVs. This differs from the case of methanol, in which RNG will be a more economical feedstock than domestic gas.[8]

This difference—that methanol will be made initially from foreign gas, whereas CNG or LNG will be made from North American gas—may give CNG and LNG an edge in "energy security." The total amount of fuel imports, and the total risk of disruption and outflow of funds, would be lower with NG fuels than with methanol.

Another resource consideration is that domestic natural gas resources will last somewhat longer if used as CNG or LNG than as methanol, because conversion losses are much less. We estimated energy losses during each of the following activities: recovery of natural gas (95% efficient), transmission and distribution of natural gas and finished product (95% efficient), reforming of NG to methanol (68% efficient), and NG liquefaction (80% efficient) or compression (94% efficient) (113). Based on these estimates, the overall energy-efficiency of the NG-to-CNG chain is about 85%, compared to 61% for NG to methanol, and 72% for NG to LNG.

Natural Gas Vehicle Technology

Internal-combustion engines may be readily adapted to operate on CNG. They may be retrofitted, as are all but about 30 of the 500,000 or so CNG vehicles currently operating worldwide, at a cost of about $1500–2000 per vehicle.

[8]That it is more economical to make methanol from RNG than from domestic gas, but more economical to make CNG from domestic gas than from RNG, is due to the fact that in the methanol case the cost advantage of the cheaper RNG feedstock relative to domestic feedstock must compensate only for higher transportation costs, but in the CNG case must compensate for the cost of liquefaction and regasification as well as for higher transportation costs. There is, in other words, an "extra step" in the RNG-LNG-CNG route (namely, LNG), compared to RNG-methanol, and this extra step is costly enough to tip the economic balance away from RNG.

The major change is the addition of one or more pressurized tanks for compressed natural gas (CNG) storage, additional fuel lines for the gaseous fuel, and a gaseous fuel mixer in the engine. A far superior vehicle would be one designed specifically for natural gas and not burdened by redundant fuel systems. A vehicle dedicated to and optimized for natural gas would have generally lower emissions than gasoline vehicles, about 10% greater energy-efficiency because of its higher octane, and similar power; it would cost about $1000 more (mass produced) because of the more costly fuel tanks, but would not have cold start problems. It would also have a shorter driving range or reduced trunk space because of the much lower volumetric energy density of gaseous fuels (see Table 7).

Natural gas can also be liquefied and stored in insulated containers. LNG storage would be more compact than CNG storage, requiring about the same space to carry a given quantity of energy as a methanol system (Table 7). LNG vehicles would have about the same life-cycle costs as CNG vehicles (as shown in Table 8), because liquefaction costs about as much as compression, and cryogenic containers cost about as much as high-pressure vessels. LNG vehicles would have more power and perhaps lower NO_x emissions than CNG vehicles. LNG probably would be liquefied at the service station by small, skid-mounted, commercially available liquefiers, rather than being liquefied

Table 7 Characteristics of energy storage systems

Vehicle	Range miles	Total weight (full) lbs	Total size gallons	Fuel dispensing time, minutes
Gasoline[a]	300	85	11	2
Methanol[b]	300	148	18	3–4
LNG[c]	300	130	27	2–4
CNG/3000 psi[c]	300	240	45	4–8
Liquid hydrogen[d]	300	100	72	3–4
Fe-Ti hydride[d]	150	640	37	5–20[e]
EV/Na-S[f]	150	700	77	20[g]–720

The baseline gasoline vehicle gets 30 mpg, lifetime average. Efficiency of other vehicles referenced to this gasoline vehicle baseline. Na-S = sodium/sulfur couple; Fe-Ti = iron-titanium.

[a] 23 lb. gasoline tank, 6.18 lbs/gal, 1.07 outer tank/inner displacement ratio.

[b] 64,000 Btu/gal (cf. 124,000 for gasoline), 6.6 lbs/gal, 15% thermal efficiency over gasoline, 37-lb. tank, 1.07 : 1 outer/inner ratio.

[c] Adapted from data in Ref. 63. Assumes fiberglass-wrapped aluminum CNG cylinders; 15% thermal efficiency advantage for CNG and LGN; weight penalty for CNG. LNG system size includes pump.

[d] Adapted from data in Ref. 61. Assumes 25% thermal efficiency advantage; weight penalty for hydride. LH_2 system size includes pump.

[e] 80% of hydride refilled in under 10 minutes.

[f] 35-kWh capacity, 120 Wh/l, 110 Wh/kg, 4.4 mi/battery-kWh (Ref. 64).

[g] Fast electric vehicle charging is theoretically possible, but requires a very large current and is possible only with certain batteries. It has not been investigated.

at large central facilities, delivered by truck, and stored in large tanks at fuel stations. There is no evidence that LNG vehicles and stations would be less safe than vehicles and stations using any other liquid or gaseous fuel (114).

Methane can be stored in carbon skeletal networks called adsorptents. The potential advantage of adsorption is that a given energy density can be attained at a pressure lower than that required to compress natural gas by itself to the same volumetric energy density. For example, an adsorptent at less than 1000 psi can attain the same volumetric energy density as CNG at over 1500 psi. This form of storage, although not yet commercially viable, may lower the cost and bulk of storing natural gas, and may make low-pressure home compression viable. In the United States, the Gas Research Institute is sponsoring R&D work aimed at commercializing adsorptents.

Currently, large numbers of CNG vehicles are operating in Italy, New Zealand, Canada, and the Soviet Union (115). All are retrofitted gasoline-powered vehicles. About 300,000 vehicles have been operating since the 1950s in Italy, mostly in fleet use. Governments in the remaining three countries initiated major CNG programs in the 1980s. In New Zealand, about 110,000 vehicles were converted to CNG, representing roughly 10% of gasoline use. When the country shifted much of its economy from the public to private sector in the late 1980s, the government withdrew the substantial subsidies it had offered to consumers and market penetration stagnated at the 10% level. The federal and provincial Canadian governments and local gas utilities offered major incentives to fuel suppliers and consumers beginning in the mid-1980s; by 1988 about 15,000 vehicles were operating on CNG, about half by households and half by fleet operators. The Soviet Union announced the intention in 1988 of converting 500,000 to 1 million vehicles to CNG by 1995, most of them taxis and trucks.

Costs

In countries with domestic supplies of natural gas, the main incentive to switch from gasoline to natural gas is lower fuel cost. NG vehicles also may have slightly lower maintenance costs than liquid-fuel vehicles. However, the vehicles themselves cost more than gasoline (or methanol) vehicles, because of the relatively expensive fuel storage equipment. The overall economic attractiveness of NG vehicles depends primarily on the balance of operating costs and initial costs.

CNG or LNG made from domestic natural gas will be less expensive than imported methanol made from RNG, and much less expensive than methanol made from domestic NG. Landed methanol will cost between \$0.40 and \$0.50 per gallon, at relatively low levels of demand for the RNG feedstock, if the low production-cost estimates prove correct. Transport, storage, and retail station costs will add about \$0.14 per gallon to the price, bringing the retail cost to at least \$9 per million Btu (mmBtu) before taxes, assuming a landed cost of \$0.45 per gallon. At the same time domestic gas will be delivered to stations for about \$5 per mmBtu, according to price projections for commercial gas (116). Based on an exhaustive review of the literature, and a detailed accounting of all costs, including land, site preparation, hook-up to the gas main, energy needed to compress gas from pipeline pressure to 3000 psi, etc, we estimate that the cost of compression and retailing is about \$3 per mmBtu (117). B.C. Gas of Canada, a marketer of CNG, also estimates \$3 per mmBtu (118). Thus a midrange estimate of the cost of CNG is \$8 per mmBtu before taxes versus about \$9 per mmBtu for methanol. LNG will cost about the same as CNG.

However, because of the high cost of high-pressure storage tanks for CNG and cryogenic vessels for LNG, NG vehicles would cost about \$1000 more than gasoline and methanol vehicles with the same range and performance. This higher upfront cost is partially compensated for by lower back-end costs: the storage systems probably will have a high salvage value, and the use of NG may increase the life of the engine, and hence increase the resale value of the vehicle.

Ownership and operating costs can be combined and expressed as a total cost per mile over the life of a vehicle, by amortizing the initial cost at an appropriate interest rate, adjusting for salvage values and vehicle life, and adding periodic costs such as maintenance, fuel, insurance, and registration. Table 8 presents the life-cycle cost of various alternative-fuel vehicles relative to a comparable, baseline gasoline vehicle. It shows the retail price per gallon of gasoline (including taxes) at which the life-cycle cost of the alternative-fuel vehicle and the comparable gasoline vehicle would be equal. This is called the "break-even" price of gasoline. As shown in Table 8, the total life-cycle cost of NG vehicles (using US NG) will be close to the life-cycle cost of gasoline vehicles at current gasoline prices, and may be less than the life-cycle cost of methanol vehicles (using remote natural gas), although the range of estimated costs overlap.

Environmental Impacts

The environmental impacts of this path are similar to those of the methanol path. At the production end, when natural gas is the feedstock, adverse environmental impacts are minimal; the recovery and transmission of natural gas causes very little pollution. When coal is gasified and upgraded to SNG, the impacts are much more severe: mining and solid waste impacts are similar to those of petroleumlike fuels, and large amounts of air pollutants are emitted, some of them toxic (see Table 1).

Emissions from NG vehicles are similar to those of methanol vehicles

Table 8 Life-cycle break-even gasoline prices,[a] 1985$/gallon

Vehicle/feedstock	Low-high feedstock or fuel cost	Extra cost of fuel storage[b]	Break-even price	
			Low	High
CNG/domestic gas	$4–6/million Btu to station	$1000–1100	0.60	1.80
LNG/domestic gas	$4–6/million Btu to station	$700–1000	0.50	1.70
Methanol/remote gas	$0.40–0.60/gallon, California	$50	1.00	1.60
Methanol/domestic coal	$0.80–1.30/gallon, plant gate	$50	1.70	2.90
Electric/—[c]	$0.05/kWh at the outlet	$3700–7400	−0.10	3.50
Electric/—[c]	$0.10/kWh at the outlet	$3700–7400	0.40	4.10
Electric/—[c]	$0.15/kWh at the outlet	$3700–7400	0.80	4.70
Hydride/solar power	$0.05–0.15/kWh on site[d]	$2000–3200	3.00	12.40
Liquid hydrogen/solar power	$0.05–0.15/kWh on site[d]	$900–2000	2.80	13.50

The important baseline assumptions used here are: 9% real interest rate for auto loans; 30 mpg, $11,500, 120,000-mile life baseline gasoline vehicle; range and fuel system assumptions as per Table 7; gasoline, methanol, CNG, LNG, and liquid hydrogen vehicles modelled at equal acceleration, EVs and hydride vehicles modelled at slower acceleration; hydrogen and electric vehicles have no pollution control equipment, natural gas and methanol vehicles have as much as gasoline vehicles; methanol vehicles assumed to have same maintenance costs and life as gasoline vehicles, electric vehicles assumed to have 25–100% longer life and 25–50% lower maintenance costs, NGVs assumed to have 0–20% longer life and 0–15% lower maintenance costs, hydrogen vehicles assumed to have plus or minus 10% of the maintenance costs and minus 5% to plus 20% of the life; all vehicles are assumed to be optimized for one fuel and produced in high volume. See Refs. 61, 63, 64 for further details and methods. Results rounded to nearest 10 cents/gallon.

[a] The break-even price of gasoline for a particular alternative is the retail gasoline price that equates the full life-cycle cost per mile of the alternative with the full cost per mile of a comparable baseline gasoline car.

[b] This is the cost of high-pressure gaseous-fuel tanks, cryogenic tanks, liquid alcohol tanks, batteries, or hydrides (for systems with attributes as in Table 7), less the cost of the gasoline tank in the baseline gasoline vehicle.

[c] Any feedstock from which electricity can be produced and distributed for between 5 and 15 cents/kWh.

[d] The estimated cost of photovoltaic electricity at the site of production.

(Table 5), although less testing and analysis has been conducted for natural gas vehicles. CNG vehicles will emit much less carbon monoxide (CO) than gasoline or methanol vehicles, because CNG mixes better with air than do liquid fuels, and does not have to be enriched for engine start-up. CO is a major wintertime problem in many cities in the United States; in 1987, 59 metropolitan areas were violating ambient CO standards. NG vehicles will emit similar or possibly higher levels of nitrogen oxides than gasoline vehicles and methanol vehicles, although little work has been done on NO_x emissions from very lean-burn methanol and NG vehicles. NG vehicles might lower ozone levels slightly more than methanol vehicles, because of the near-zero reactivity of methane itself (the primary HC in the exhaust of NG vehicles), although this assessment is unsubstantiated because no ozone testing of NG vehicles emissions has ever been conducted (119).

The use of CNG or LNG made from natural gas would lead to small reductions in emissions of greenhouse gases (including methane) from the fuel production and use cycle, compared to gasoline and diesel fuel (Table 4). However, if coal were used as the feedstock instead of natural gas, emissions of greenhouse gases would increase considerably.

Like methanol, NG in heavy-duty engines produces essentially no SO_x, particulates, smoke, or unregulated pollutants. A natural gas-fuel spark-ignition engine with a three-way catalyst produces very little nonmethane HCs and NO_x. Perhaps the most promising approach is ultra-lean-burn operation, which in an NG spark-ignition heavy-duty engine at an early stage of development has already resulted in low NO_x and CO emissions (120, 121). The use of NG in heavy-duty spark-ignition engines wth three-way catalysts, or in ultra-lean-burn engines, may prove to be the most inexpensive way of meeting 1994 particulate and NO_x standards. Cummins and other manufacturers of heavy engines are developing NG engine technology.

Opportunities for Natural Gas Vehicles

Natural gas (NG) vehicles have received relatively little attention in the United States. One reason is that gas utilities, who are the local suppliers and would be the principal or sole marketer of gas to motorists, have until quite recently shown little interest in CNG, understandably making other organizations, especially government agencies, reluctant to invest the time and resources necessary to introduce this new fuel. The reason for utility indifference is rooted in decades of government regulation that built a web of rules that effectively removed the incentive for gas utilities to market CNG to the transportation market (122). These rules are being phased out in the late 1980s, but significant impediments to gas marketing remain.

Until very recently CNG has had few proponents in the United States, and therefore no constituency, to help it overcome the barriers that obstruct its introduction. The formation in August 1988 of the Natural Gas Vehicle Coalition may prove an important first step in generating support for NG vehicles. This lobbying and promotional group will solicit participation not only from the gas industry but also from the vehicle manufacturing industry, state and local governments, the environmental community, and the oil industry, and may accomplish for NG vehicles what the farm lobby has accomplished with ethanol fuel.

The other major reason for the lack of interest in NG vehicles in the United States is that a transition from gasoline to NG vehicles would be fairly difficult—more difficult than a transition to methanol—especially in a country wary of government planning. A transition to NG vehicles is not likely to proceed incrementally via dual-fuel NG/gasoline vehicles that operate on NG or gasoline, because these vehicles are generally inferior to gasoline vehicles: they would cost about $1000 more if factory-made on a large scale ($1500–2000 if retrofit), perform much worse on CNG, and have less trunk space because of the NG tank. Only people who cared little about the loss of power and trunk space, and were willing to wait a few years for the lower price of

NG (compared to gasoline) to reward the investment in the NG system, would buy dual-fuel vehicles; it is not likely that many people would be so inclined. In contrast, a dual-fuel methanol/gasoline vehicle has one fuel storage and delivery system and so retains all its trunk space, costs only slightly more than a gasoline vehicle when factory-made, and when operating on methanol actually has slightly more power.[9]

Government mandates or incentives could stimulate the market for dual-fuel NG vehicles, just as they could the market for dual-fuel alcohol/gasoline vehicles. However, if the federal government were willing to get involved, it might orchestrate a direct transition to dedicated NGVs. This probably would be preferable, because dedicated NGVs are far superior to dual-fuel NG/gasoline vehicles. A transition directly to dedicated NGVs would require nearly simultaneous introduction of dedicated vehicles and establishment of an extensive refueling network in relatively large markets, such as the Los Angeles region. (The refueling network would have to be extensive because dedicated NGVs, unlike dual-fuel vehicles, can use only NG, and so NG would have to be widely available to support dedicated vehicles.) The start-up costs would be greater than the start-up costs of a methanol system, because of the greater expense for vehicles and stations.

It probably would be difficult in the United States to find politically acceptable justification for such extensive government planning and investment. At a minimum, the public would have to be convinced that methane fuels are environmentally superior to gasoline and methanol, that NG vehicles have lower life-cycle costs than methanol and gasoline vehicles, that NG fuels enhance national energy security, and that market forces alone will not motivate a transition to NG vehicles. The natural gas industry, a large and diverse group containing gas exploration and production companies (many of which are also major oil companies), gas pipeline companies, gas equipment suppliers, and gas utilities, would have to promote NG vehicles aggressively.

In sum, a methane fuel path is, in general, superior to a methanol path from an energy security and, to a lesser extent, economic perspective, but the transition is more difficult and requires more government intervention. The environmental impacts would be similar.

[9]Methanol's advantage in dual-fuel vehicles may be diminished, however, by consumer fuel-purchasing behavior. Once individuals purchased a CNG dual-fuel vehicle, they would be inclined to refuel with CNG as much as possible, because CNG fuel will be less expensive than gasoline. Operators of methanol dual-fuel vehicles, on the other hand, may not be as inclined to purchase methanol because the methanol will cost more than gasoline (or about the same if the price is subsidized). In short, the owner of the dual-fuel NG/gasoline vehicle has an economic incentive to use NG; the owner of the methanol/gasoline vehicle does not.

HYDROGEN AND CLEAN ELECTRICITY

At the opposite end of the environmental and technological compatibility spectrum from petroleumlike fuels made from coal and oil shale are hydrogen and electricity made from clean and renewable energy sources. Whereas these synthetic fuels could replace gasoline and diesel fuel with no modifications to vehicles or fuel delivery systems, hydrogen is a gas, and would require special vehicular storage, a redesigned engine, completely new fuel stations, and a pipeline distribution system. Electric vehicles, of course, would require even more changes. While synthetic fuels would be more environmentally damaging than gasoline and diesel fuel, clean hydrogen and electricity would be virtually pollution-free.

Hydrogen and electric vehicles are linked here because they both are part of a potentially sustainable and very clean energy path and both could use the same clean sources of energy. Battery-powered (or roadway-powered) electric vehicles can use electricity made with solar or nuclear power (from fission or fusion reactors), and hydrogen-powered vehicles could use solar or nuclear power to split water to make hydrogen. This path would be followed if great emphasis is placed on reducing environmental pollution and global warming and on creating a permanently sustainable energy supply system.

Hydrogen

Hydrogen is an attractive transportation fuel in two important ways: it is the least polluting fuel that can be used in an internal combustion engine, and it is potentially available wherever there is water and a clean source of power. The prospect of a clean, widely available transportation fuel has motivated much of the research on hydrogen fuels. The technology for cleanly producing, storing and combusting hydrogen is far from commercialization, and thus we explore a larger range of technology options in this section.

PRODUCTION Hydrogen can be produced from water or fossil fuels. Fossil fuels consist of hydrocarbon molecules that can be reformed, cracked, oxidized, or gasified to produce hydrogen. Coal is relatively abundant and could provide a low-cost feedstock for hydrogen for many decades, but if coal or other fossil fuels are to be used, it might be more attractive to convert them to liquid or gaseous fuels with a higher volumetric energy density. In addition, the conversion of fossil energy to hydrogen fuels would cause major environmental impacts and would not be a renewable energy path. Most of the hydrogen research community agrees that if hydrogen is to be used as a fuel, the most attractive source is water (123).

There are several methods for splitting water to produce hydrogen: thermal and thermochemical conversion, photolysis, and electrolysis. Electrolysis, the use of electricity to split water into hydrogen and oxygen, is the most developed method. The cost and environmental impact of producing hydrogen from water depend on the primary energy used to generate the electricity to split the water. Fossil fuels would not be used as the source of electric power because it would be cheaper and more efficient and would generate less carbon dioxide to make the hydrogen directly from the fossil fuels. Hence nonfossil feedstocks, such as solar, geothermal, wind, hydro, and nuclear energy, would be used to generate electricity for the electrolysis process. Of these, solar energy and nuclear energy (from breeder reactors or possibly fusion plants) will potentially be available in the greatest quantities for the long term.

VEHICULAR FUEL STORAGE The principal obstacle, other than costs, to using hydrogen in vehicles is hydrogen's very low volumetric energy density as a gas at ambient temperature and pressure. Hydrogen's density may be increased by storing it on board a vehicle as a gas bound with certain metals (hydrides), as a liquid in cryogenic containers, as a highly compressed gas (up to 10,000 psi) in ultra-high-pressure vessels, as a liquid hydride, and in other forms. Most research has focused on hydride and liquid hydrogen storage.

Hydride storage units, which include housings for the hydrides and the coolant systems, are very large, from 25 to more than 80 gallons, and quite heavy, 250 to 1000 lbs (Table 7). Barring major improvements in vehicular fuel-efficiency, hydride vehicles would be limited by storage weight to a range of about 100 to 200 miles. Liquid hydrogen must be stored in double-walled, superinsulated vessels designed to minimize heat transfer and the boil off of liquid hydrogen. Liquid hydrogen systems are much lighter and often more compact than hydride systems providing an equal range. In fact, liquid hydrogen storage is not significantly heavier than gasoline storage, on an equal-range basis, although it is about six times bulkier (Table 7).

In summary, all hydrogen storage systems systems are bulky and costly and will remain so, even with major advances. Hydrogen vehicles will be successfully introduced only if users are willing to accept vehicles with much larger fuel tanks and shorter ranges than other vehicles.

ENVIRONMENTAL IMPACTS OF HYDROGEN VEHICLES The attraction of hydrogen is nearly pollution-free combustion. While many undesirable compounds are emitted by gasoline and diesel fuel vehicles, or formed from their emissions, the main combustion product of hydrogen is water. Hydrogen vehicles would not produce significant amounts of CO or HCs (only small amounts from the combustion of lubricating oil), particulates, SO_x, ozone, lead, smoke, benzene, or CO_2 or other greenhouse gases (Tables 4 and 5). If hydrogen is made from water using a clean power source, then hydrogen production and distribution will be pollution-free.

The only pollutant of concern would be NO_x, which is formed, as in all internal-combustion engines, from nitrogen taken from the air during combustion. With lean operation, and some form of combustion cooling such as exhaust gas recirculation, water injection or the use of very cold fuel (i.e. liquid hydrogen), but with no catalytic control equipment on the engine, an optimized hydrogen vehicle probably could meet the current US NO_x standard, and probably have lower lifetime average NO_x emissions than a current-model catalyst-equipped gasoline vehicle (124).

The use of hydrogen made from nonfossil electricity and water is one of the most effective ways to reduce anthropogenic emissions of greenhouse gases. Highway vehicles burning hydrogen would emit essentially no CO_2 or CH_4, and because they would emit no reactive hydrocarbons (precursors to ozone formation in the troposphere), would help reduce ozone (Tables 4 & 5).

NUCLEAR VERSUS SOLAR Solar electrolytic hydrogen is environmentally and politically preferable to nuclear electrolytic hydrogen, for several reasons. First, although the nuclear power industry is developing "passively safe" reactors, such as the high-temperature gas-cooled reactor, which rely on physical laws rather than human corrective action to safely resolve emergencies (125), it is not clear if the public, regulatory agencies, and financial backers will be convinced that these are safe enough to warrant a large expansion of nuclear power. Second, if nuclear power were aggressively developed, the reprocessing of spent nuclear fuel and reprocessing of plutonium for breeder reactors would circulate large amounts of weapons-grade nuclear material (126). Third, and perhaps most importantly, long-term underground disposal of nuclear wastes remains environmentally controversial.

Solar power production is much less risky environmentally and politically; even concern over the amount of land devoted to photovoltaic (PV) systems may be misplaced, as it has been estimated that PV power generation (assuming 15% efficiency) requires only three times more acreage per unit of energy produced than nuclear power generation, when mining, transportation, and waste disposal are considered (127). In the hydrogen vehicle cost analyses below, we consider solar photovoltaic energy as the primary energy source.

COST Hydrogen's environmental advantages must compensate for the very high cost of hydrogen fuel and the high cost of hydrogen storage systems. Hydrogen fuel is expensive primarily because electricity is relatively expensive (and 5–25% of the energy in the electricity is lost in the electrolysis process). We assume that hydrogen is produced from photovoltaic power costing between 5 and 15 cents per kWh at the generation site (128). With this assumption, Table 8 shows the price of gasoline that would be required to make the life-cycle cost of a gasoline and hydrogen vehicle equal (the other assumptions are discussed in the notes to Table 8). In the high-cost cases, both hydride and liquid hydrogen vehicles are prohibitively expensive compared to gasoline vehicles. Even in the low-cost case, the low break-even price is about $3.00 per gallon; in other words, gasoline would have to sell for more than $3.00 per gallon for hydrogen vehicles (using hydrogen made from water with solar power) to be economically competitive. Thus, it appears that hydrogen vehicles will be cost-competitive in the middle term only if the most optimistic cost projections are realized and the price of gasoline at least triples.

OPPORTUNITIES FOR HYDROGEN The attractiveness of hydrogen vehicles hinges on technological progress in three areas. First, in order to increase hydride vehicle range and performance, hydrides with high mass energy density, low dissociation temperature, and relatively low susceptibility to degradation by gas impurities must be found. At present, the probability of hydride vehicles achieving performance and range parity with gasoline vehicles seems low. Second, the loss of trunk space to bulky hydrogen storage systems needs to be minimized. Hydrogen storage systems are many times larger than gasoline tanks of equal range. Barring dramatic advances in technology, this disparity is not likely to change. Third, reliable, low-cost boil-off control devices must be developed for liquid hydrogen vehicles so that the vehicles can be left for a week or more in enclosed areas without creating safety hazards.

The most attractive feature of hydrogen is its very low pollutant emissions, including greenhouse gases. The most fundamental barrier is cost. Therefore, if hydrogen is to be introduced as a transportation fuel, optimistic projections of the cost of hydrogen vehicles and hydrogen fuel must be realized, and a relatively high value must be placed on reducing air pollution, avoiding greenhouse warming, and reducing dependence on finite and imported energy resources.

In conclusion, while hydrogen fuel is not a near-term option, it is also not strictly an exotic, distant-future possibility. Although all hydrogen vehicles have serious shortcomings, none of the problems are necessarily insurmountable. With a strong R&D effort, normal technological progress, and continuing reductions in the cost of solar electricity, hydrogen vehicles could be cost-competitive on a social cost basis (taking into consideration air pollution, energy security, global warming, etc) within perhaps 30 years.

Electric Vehicles

A cost-effective, high-performance electric vehicle (EV), recharged quickly by solar (or perhaps nuclear) power, using widely available battery materials, would be an attractive transportation machine. Progress over the last 10 years has brought this ideal closer to reality.

Interest in electric vehicles has peaked three times in the past few decades, with concern about air quality in the mid-1960s, about imported petroleum in 1974–1981, and with renewed interest in reducing petroleum imports and pollution from automobiles from about the mid-1980s to the present. Although most reports and statements in the United States emphasize methanol as a replacement for gasoline and diesel fuel, there is increasing awareness of the potential for advanced EVs with acceptable performance to provide substantial air quality and petroleum conservation benefits, at comparatively low cost.

PERFORMANCE OF EVS Electric vehicles were commonplace in the United States at the turn of the century. However, by 1920 improvements in EV technology had lagged so far behind the development of the internal-combustion engine that EVs became practically extinct (129). With the resurgence of interest in EVs in the 1960s came promises of breakthroughs that were to make EVs as economical and high-performing as internal-combustion engine vehicles. But a decade later the promised EV had still not materialized.

The efforts of the past decade have not produced any dramatic breakthroughs. However, over that period the technology of EV batteries and power trains has developed incrementally, and the cumulative result is substantial. For example, advances in microelectronics have resulted in low-cost, light-weight dc-to-ac inverters, which make it attractive to use ac rather than dc motors. With the improved inverters the entire ac system is cheaper, more compact, more reliable, easier to maintain, more efficient, and more adaptable to regenerative braking than the dc systems that have been used in virtually all EVs to date. Similarly, the development of advanced batteries, particularly the high-temperature sodium/sulfur battery, has progressed to the point where successful commercialization does not depend on major technical breakthroughs, but on the resolution of manufacturing and quality control problems. Several major auto manufacturers expect to mass produce EVs with ac power trains and sodium/sulfur batteries in the 1990s (130).

Advanced EVs now under development, and projected to be commercially available within a decade, are expected to offer considerably better range and performance than state-of-the art EVs of 10 years ago. Without sacrificing seating or cargo capacity, passenger vehicles and vans are projected to have urban ranges of about 150 miles, high top speeds and acceptable acceleration, and low energy consumption. With these characteristics, EVs would be attractive as second vehicles in most multicar households (131, 132) and as vans in most urban fleets (133, 134). As personal vehicles become more specialized and expectations regarding multipurpose usage of vehicles continue to diminish, EVs may even become acceptable as primary commuter cars. Exotic batteries under development, such as the aluminum-air battery, that promise even longer ranges and faster recharging, could eventually make EVs the vehicle of choice in a world of high energy prices and heightened environmental concern.

COST If the most optimistic cost conditions are satisfied—high vehicle efficiency, high battery energy density, low-cost off-peak power, low initial battery cost, long battery cycle-life, long EV life, and low maintenance costs—then EVs will have much lower life-cycle costs than comparable gasoline vehicles and will be economically competitive even if gasoline is free (Table 8). However, under high-cost conditions, EVs will not be cost-competitive until gasoline sells for \$3–4 per gallon (Table 8). If electricity is more expensive, in the range of 10 to 15¢ per kWh, the break-even price is about \$4–5 per gallon in the high-cost case. The great difference between the high and low break-even gasoline prices is due primarily to uncertainty about the cost of batteries and the life of EVs relative to the life of internal-combustion engine vehicles.

ENVIRONMENTAL IMPACTS A principal attraction of electric vehicles is the promise of improved urban air quality. If EVs use solar power, then they will be essentially nonpolluting. But even if they were to consume electricity generated in a combination of power plants using coal, natural gas, oil, hydroelectric power, nuclear power, and solar power, they would still provide a major reduction in emissions (135, 136; see Table 5).

Regardless of the type of power plant, fuel, and emission controls employed, EV use will practically eliminate CO and HC emissions on a per-mile basis, relative to gasoline vehicles meeting future stringent emission standards. NO_x and particulate emissions will be reduced with EV use if at least moderate controls are used. SO_x emissions will be practically eliminated if natural gas is used to generate electricity, but will increase if coal is used—by severalfold, in the case of uncontrolled or moderately controlled coal steam plants. It should be noted that the light-duty transportation sector is now a major source of HC, CO, and NO_x emissions, but a very minor source of SO_x and particulates, and that CO and ozone are the major urban air pollution problems. Thus, a large decrease in HC, CO, and NO_x emissions from light-duty highway vehicles would have a greater impact on urban ambient air quality than would a moderate increase in SO_x emissions. As a result, regardless of the feedstock used for electricity generation, EVs will tend to improve urban air quality significantly.

The impact of EV use on greenhouse gas emissions is more mixed and much more sensitive to the type of electricity feedstock used. Fossil-fuel-burning power plants emit several greenhouse gases, as well as the regulated pollutants discussed above. Table 4 shows the results of substituting EVs for internal-combustion engine vehicles, expressed as percent change per mile in emissions of a composite greenhouse gas (CO_2 equivalents, as explained above). On a per-mile basis, the use of coal-fired power by EVs will cause a moderate increase in emissions of all greenhouse gases, relative to current emissions associated with the use of gasoline and diesel fuel. If natural gas is used, there will be a moderate decrease in emissions of greenhouse gases, mainly because of the low carbon-to-hydrogen ratio of natural gas. If EVs are powered by the mix of electricity sources existing in the United States in 1985, then about the same quantity of greenhouse gases will be emitted as was emitted by the use of gasoline and diesel fuel vehicles in 1985. If nonfossil fuels (nuclear, solar, hydroelectric power, or biomass fuels) are used in all engines, there will be essentially zero emissions of greenhouse gases.

OPPORTUNITIES FOR EVS EVs probably will be introduced with relatively little government involvement, for three reasons. First, utilities generally support the use of EVs, because they expect EVs to draw power from otherwise idle capacity and not to require the construction of new plants. Given appropriate time-of-use rates (or other load management), most recharging of EVs will be postponed until late at night, when electric utilities have ample capacity available and the use of oil, which is generally a peaking fuel, is at a minimum. Studies of the impact of EV use on utility energy supply have shown consistently that US utilities have sufficient capacity in place to support many millions—even tens of millions—of electric vehicles, charging off-peak (137–139).

Second, the life-cycle cost of advanced, mass-produced EVs, using cheap off-peak power, probably will be low enough to induce some fleet operators and home owners to purchase those vehicles. Third, vehicle sales will not be hindered initially as much as methanol and CNG vehicles by the absence of a fuel distribution network, because one already is in place. Electricity is available virtually everywhere, and most homes and businesses can set up an EV charging station for well under $1000 (140). These relatively small costs and start-up barriers (the "chicken-and-the-egg" problem) mean that the market penetration of EVs can proceed, to a point, largely by market forces.[10] The most important role of government may be to coordinate or make large purchases of EVs, allowing manufacturers to achieve economies of scale in production. The government could justify this modest role on environmental grounds.

[10]The Electric Vehicle Development Corporation, a private group supported by electric utilities, battery manufacturers, and auto manufacturers, is developing markets and service infrastructure for EVs (141).

The degree of market penetration by EVs will depend initially on their range, performance, and life-cycle cost. In the near future, EVs will be attractive in some urban fleets; as the technology improves and vehicles are produced in large quantities, EVs may be attractive as commuter vehicles. However, even if advanced EVs prove to be as high-performing and economical as can be hoped, and are favored by public policy for their environmental benefits, there still will be one significant obstacle to widespread consumer acceptance: the long recharging time. If it takes eight hours to recharge an EV, most households will want at least one nonelectric vehicle, and EVs will be limited to the role of second car in some multicar, home-owning households. However, if EVs can be charged in under 30 minutes, they may be able to displace gasoline vehicles in many more applications, and gain a large share of the vehicle market; they may be suitable for all applications except those requiring more power than even advanced batteries can provide.

There are several ways of quickly recharging EVs, including swapping discharged batteries for previously fully charged ones, using mechanically rechargeable batteries (e.g. aluminum-air batteries), and using ultra-high-current recharging. None of these methods has been demonstrated, however, and all are likely to be expensive. Much more work is needed in this area.

The successful completion of advanced EV development programs, and the development of means of quickly recharging EVs, would make the EV a competitive alternative to internal-combustion vehicles. The combination of large environmental benefits and potentially low private cost in the near term, and the prospect of a pollution-free feedstock in the long-run, may well make EVs the option with the lowest social cost. In the meantime, though, EVs may be economical, on a private-cost basis, in some applications today.

In summary, EVs and hydrogen vehicles require substantial improvements before they become attractive as the dominant transportation technology. For that to happen, R&D investments must be expanded greatly. A clean electricity and hydrogen path will come into being in a timely manner only if society places much greater emphasis on reducing air pollution and slowing the greenhouse effect.

COMPARATIVE ANALYSIS

Facts, Beliefs, and Values

How, when, and where should we initiate a transition to alternative transportation fuels? There is no obvious answer and no consensus. The price of petroleum cannot be predicted, and many of the costs and benefits of alternative fuels are difficult to quantify. Different groups place different values on the important (nonmarket) concerns: energy security, air quality, global warming, and the ease and convenience of a transition. In short, different beliefs and different values, and familiarity with different facts, lead individuals and organizations to different conclusions about the most desirable path.

The choice of transportation energy paths should focus on values and goals, rather than on projections of market costs, especially when projected costs do not differ much between energy options or are based on technologies that are still far from commercialization (and likely to become much less expensive with learning curve improvements). Current and projected market prices can be poor criteria for long-term energy choices. Shifting societal goals, values, and preferences will result in redirected government initiatives that will change relative energy prices, while the long-term replacement of today's sunk investments will also cause a shift in long-term energy prices. We should therefore take care not to allow current and extrapolated energy prices to overly influence transition strategies. In the words of Herman Daly, "the choice between . . . energy futures is price determining, not price-determined" (142).

The choice of transportation energy paths also should be open-minded and flexible. There is no one optimal choice for everyone, or every region; the era of one (or two) uniform transportation fuels may be over. This prospective multiplicity of fuel options presents a challenge for business and government. Because many of the benefits resulting from initial alternative-fuel investments do not accrue to the private sector supplier of the fuel, government must take much of the initiative. But which fuels should it choose and how fast should it introduce them?

If concerns for self-sufficiency and energy independence dominate in a country, then that country should prefer energy options based on abundant domestic resources. The United States would favor biomass and fuels from coal and oil shale, domestic natural gas, and domestic electricity. Remote natural gas, imported as LNG or methanol, would be deemphasized.

If economic efficiency, measured by conventional market indicators, is the dominating value, then hydrogen would be discarded as an option. Electric vehicles would be competitive in some applications if optimistic battery cost and performance goals were met. For the larger passenger and heavy-duty vehicle markets, natural gas vehicles probably would be favored, as would methanol if low-cost methanol production estimates prove accurate.

If environmental quality and sustainability take precedence, then hydrogen and electric vehicles, using clean and renewable energy (probably solar power), would be preferred. Methanol and NG vehicles, regardless of the feedstocks, would be deployed as transitional options only, if at all.

If the abiding objective is to make the transition with as little disruption as possible, then petroleumlike fuels would be favored. The large-scale nature of synthetic fuel production plants matches well with current investment and management patterns of oil companies—large, capital-intensive facilities connected by a network of pipelines to end-use markets. But these fuels are also the least attractive environmentally and are among the more expensive options.

A transition to methanol would be more difficult than a transition to petroleumlike fuels, requiring modifications to vehicles, storage tanks, and delivery systems, but it would be less difficult than a transition to gaseous fuels. A transition to EVs would be relatively easy from an infrastructure standpoint, assuming that the cost and difficulty of establishing home recharging stations would not be great. However, the potential for EVs is limited by the weight and low energy density of batteries and the long recharging time.

If the most important concern is to avoid a greenhouse warming, EVs using nonfossil power may be the best choice, because they offer the best opportunity to immediately reduce emissions of greenhouse gases from the highway sector. Internal-combustion engine vehicles using hydrogen made from water with nonfossil power would also emit only negligible amounts of greenhouse gases, but hydrogen vehicles are not likely to be commercially available as soon as EVs. ICEVs using methanol or gas derived from biomass likewise would emit only small amounts of greenhouse gases, but the biomass resource base is limited, the use of these biomass fuels is much more polluting than the use of clean power by EVs, and biomass cultivation demands careful soil management.

Other values and goals could and should play instrumental roles—equity and distribution of power and wealth, growth versus stability, free enterprise, individual initiative, and public health—but the issues discussed here of environmental quality, greenhouse effects, sunk investment, compatibility, and energy security have come to dominate the public debate.

RECOMMENDATIONS AND CONCLUSIONS

In the 1970s the preferred petroleum alternatives were so-called synthetic fuels made from coal and oil shale that imitated gasoline and diesel fuel. Around 1984 or so, conventional wisdom shifted to methanol as the fuel of the future. In both cases a driving force was the perception of a lack of adaptability by the oil and automobile industries. Resistance to fuels different from gasoline and diesel fuel eased in light of economic and environmental problems of synfuels. Will economic forces motivate another shift, to natural gas? Will environmental forces compel an even more drastic shift, to hydrogen or electric vehicles? The ease and speed with which conventional wisdom can dismiss alternatives and coalesce around a particular option is remarkable—and disturbing.

R&D Recommendations

Definitive analytical evidence to support transportation energy choices and the formulation of transportation energy policies is not possible at this time. Increased knowledge is needed in the following research areas to inform the decisionmaking process.

1. Since, in general, the more that is learned about pollution and other externalities, the more harmful or costly they prove to be (143), we recommend that considerably more resources be devoted to learning about them. The most pressing need, largely because air pollution is the primary motivation driving the introduction of alternative fuels at this time, is to test and mathematically model emissions and ozone formation under the same sets of conditions for all alternative fuels.

2. The key areas to target for technological improvement of vehicles are the recharging time of advanced batteries, the cost and high-density storage performance of adsorptents for natural gas, the further development of reliable and cost-effective control of gases boiled off from cryogenic fuels, and improvements in the mass energy density and desorption temperatures of metal hydrides.

3. Consumer reaction to large batteries and fuel storage tanks, longer refueling times, reduced vehicle range, and cryogenic boil-off should be studied carefully. These are important aspects of the attractiveness of hydrogen and electric vehicles and, to a lesser extent, NG and methanol vehicles.

4. Because of the very large size of US coal reserves, development of clean processes for converting coal into liquid and gaseous fuels should continue, to determine how cleanly and inexpensively the fuels can be produced. We remain cautious about this option, however, because of the large amount of CO_2 produced from coal-based fuels.

5. Considerably more effort should be devoted to improving thermochemical and hydrolysis processes for converting cellulosic biomass into alcohol fuel. Biomass-based transportation fuels will probably cost about the same as coal-based fuels (perhaps less), would produce almost no greenhouse gases, and would be permanently available.

6. Clean electricity should figure prominently in our transportation future, powering electric vehicles or splitting water to make hydrogen. Accelerated research and development of sustainable, pollution-free electricity-generating technologies, especially photovoltaics, should be a cornerstone of national energy policy. Solar energy should prove to be the most cost-effective source of renewable, clean, non-CO_2 producing energy available. (We are less optimistic about nuclear power, because of the safety and environmental issues mentioned above.)

7. The disparity between the need for nonpetroleum fuels and the long-term shortcomings of all the alternatives identified so far underscores the need for

further research and development. Much more basic R&D on optimal engines and fuel storage systems should be done. Engine tests should be performed to provide a coherent basis for evaluating emissions, power, efficiency, and cost. To our knowledge, no vehicular engine optimized in all respects for hydrogen, natural gas, or even methanol exists. It appears that most automotive industry research is now devoted to multifuel alcohol-gasoline engines, not optimized engines. Engines optimized with respect to performance and emission parameters, for given engine costs, should be built and evaluated for each fuel type.

To make even a tentative national and even global commitment to a new fuel without this knowledge seems foolish.

Transition Strategy Recommendations

As indicated above, there is no analytical basis for definitively determining which fuel is superior and when it should be introduced. The choice depends upon one's values, forecasts of future energy prices and political events, technological advances, and increased knowledge about the greenhouse effect.

Nonetheless, choices must be made with incomplete knowledge and limited foresight. Based on our belief that a transition to alternative fuels is important but not extremely urgent at this time and that pollution and environmental damage should weigh heavily in decisionmaking, we make the following recommendations for an energy transition plan. These recommendations are for the conditions prevailing in the United States, but are relevant for many other countries as well.

1. In the near term, CNG and EVs should be aggressively promoted so as to expand their use in market niches where they are economically attractive. These are the only options that (in the best case) can compete with gasoline when oil is in the range of $15 per barrel. They should especially be supported in areas with CO and ozone problems.

2. Advances in the use of methanol and CNG use in diesel engines should be aggressively pursued, since both fuels provide major emission benefits and may be economically competitive with diesel fuel after the 1991/94 emission standards take effect. Particular emphasis should be placed on centrally fueled fleets.

3. In the near term, the introduction of methanol into spark-ignition engines should receive similar emphasis to CNG and electric vehicles. Since methanol does not offer significant air quality, greenhouse, or energy security benefits (144) and, unlike CNG and EVs, is not attractive in any market niches, perhaps methanol is best treated as a transitional "filler," along with NG vehicles, after CNG and EV niche markets are saturated and oil prices rise to perhaps $30 per barrel.

4. A logical strategy for the next century, when natural gas–based fuels are likely to play a large role, is to introduce methanol in mild climates, where cold starting is not a problem, and along coastal areas and major waterways where fuel distribution would not be costly, and to introduce NG vehicles elsewhere where gas pipelines are already in place.

To summarize, we urge continued efforts in introducing methanol and CNG fuel, but it should be recognized that they are not long-term solutions, though they may prove to be the preferred fuels in the first half of the 21st century. The long-term and possibly permanent transportation fuels will probably be a mix of electricity, hydrogen, and biomass fuels. These fuels provide the potential for a qualitatively superior and sustainable future. We should act now with this in mind.

ACKNOWLEDGMENTS

We gratefully acknowledge funding from the University of California Policy Seminar, Transportation Center, and Energy Research Group, and careful reviews of the manuscript by Bruce Beyaert and Robert Socolow.

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