Chapter IV

Fuel Switching

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INTRODUCTION

Fuel use patterns in the United States have changed several times in the past 150 years. During the late 1800s, coal overtook wood as the principal fuel; and in this century oil and then natural gas use surpassed coal consumption.

In more recent years, however, the trend towards more oil and gas use has been reversed, at least temporarily. Between 1978 and 1982, oil use in the electric utility sector, as a percent of their total energy consumption, dropped from 17 percent in 1978 to 7 percent in 1982, while gas use remained relatively constant. Because electricity sales remained nearly constant, the drop in oil use was accompanied by an increase in coal consumption and, to a lesser extent, increased generation from hydroelectric facilities. (Nuclear power output remained nearly constant during the period.[1])

At the same time, residential and commercial consumption of oil, as a percent of total energy use (including wood[2]), dropped from 1s percent in 1978 to 9 percent in 1982, while natural gas's share of total consumption remained relatively constant. The drop in oil use was accompanied by an increase in electricity and, to a lesser extent, wood consumption.

Fuel use patterns in the industrial and transportation sectors, on the other hand, remained relatively constant during this period. In the industrial sector, oil and gas use, as a percent of total energy consumption, dropped by about 1 percentage point each between 1978 and 1982. The transportation sector remained primarily dependent on petroleum (except for natural gas used to pump gas through pipelines), although the use of natural gas and ethanol in cars and trucks increased slightly.

In all, petroleum consumption dropped from 47 percent of the total U.S. energy consumption in 1978 to 41 percent in 1982. Natural gas' share remained constant at 25 percent and coal's share increased from 17 to 21 percent in this period. The remainder was made up primarily of small increases in the shares of hydroelectric and nuclear generation and wood. These changes in the mix of fuels used, defined as "fuel switching, " together with increased efficiency and reduced demand for energy services lowered U.S. demand for petroleum from 18.8 million barrels per day (MMB/D) in 1978 to 15.3 MMB/D in 1982, or about 19 percent.

In the event of a large oil shortfall, continued and accelerated fuel switching away from oil will be an important means of restoring the energy services formerly supplied by oil. Fuel switching often involves installation of new equipment, may require expansion of alternative fuel delivery systems, and always involves increased supplies of the alternative fuel.

In this chapter OTA considers several types of fuel switching in order to estimate their potential for replacing the petroleum lost in an oil shortfall. The next two sections summarize the fuel switching options examined and describe some of the technologies involved. Fuel supply constraints, including the potential for enhanced oil recovery, are then analyzed, followed by estimates of the rates that various technologies can be deployed. The chapter concludes with a brief summary of environmental impacts.

[1] "Monthly Energy Review, " Energy Information Administration, DOE/EIA-0035(83/10), October 1983.

[2] "Estimates of Wood Energy Consumption From 1949 to 1981 ," Energy Information Administration, DOE/EIA-0341, August 1982.

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OPTIONS CONSIDERED

The oil replacement potential through fuel switching was assessed in a two-stage process. First a comprehensive list of major near-term fuel switching options (table 6) was screened to identify those options with the greatest potential for replacing large quantities of oil in a relatively short period of time. The options surviving the screening process were then examined in detail to estimate more precisely the quantities of oil that each could replace and the rate at which the technologies could be deployed.

For the purposes of this study, the options that were eliminated from further consideration were those that seemed least likely to be able to replace more than about 0.2 MMB/D of petroleum within 5 years after the onset of an oil shortfall beginning in 1985. Although most of the options listed in table 6 could replace significant quantities of oil if sufficient resources were devoted to deploying them, and some of the options eliminated could be important in specific localities, the screening process identified options most likely to be used extensively throughout the country. Some of the options eliminated and the specific reasons for eliminating them are given in appendix A to this chapter.

The remaining fuel switching technologies, grouped into the aggregated categories which have been considered in more detail, are listed in table 7. The major options involve converting stationary uses of oil to electricity, natural gas, coal, and solid biomass. These fuels can also be used as replacements for liquid fuels in the transportation sector, but the constraints are considerably more severe than for stationary oil uses.[3] Ethanol from grain is also included for more detailed consideration, because it is a well-established technology that produces a high-grade liquid fuel, the leadtime for constructing distilleries is normally less than 3 years, and the distillery does not need to depend directly on oil or natural gas as a fuel.

[3]Electric vehicles were also eliminated from detailed Considersration because of the severity of these constraints.

Table 6.—Oil Replacement Technologies Selected for Screening Evaluation

Energy supply/ technology-description	Remarks/examples
Natural gas in buildings, industries and electric utilities	Switch over from distillate/ residual fuel oil to natural gas
Electricity in buildings	Use of heat pumps, resistance heaters and space heaters
Coal and/or wood in buildings	—
Coal and solid wastes in industries and electric utilities	Direct firing of coal
Coal-liquid mixtures	Coal-oil, coal-water mixtures
Coal gasification	Low- and medium-Btu gasification
Coal liquefaction	
Oil shale, tar sands	
Solar energy	Use in buildings, industries and electric utilities
Wood in industries and electric utilities	Direct-firing both sectors; gasification in industries
Biomass liquid fuels in transportation	Use of ethanol from corn
Natural gas and LPG in transportation	—
Electricity in transportation	—
Mobile coal and wood gasifiers for transportation	—
Enhanced oil recovery	—
Increased natural gas production storage and delivery	—

SOURCE: Office of Technology Assessment

Table 7.—Categories of Oil Replacement Technologies Evaluated in Detail

Sector	Technologies
Electric utilities	Conversions to solid fuels and natural gas Completion of new generating facilities currently under construction
Residential and commercial space heat and hot water	Conversion to natural gas, electricity, and solid fuels
Industry	Conversion of boilers to solid fuels and natural gas
Transportation	Conversion to compressed natural gas, liquefied petroleum gas, and solid fuels (with mobile gasifiers) Increased ethanol production
All	Enhanced oil recovery

SOURCE: Office of Technology Assessment.

TECHNOLOGIES

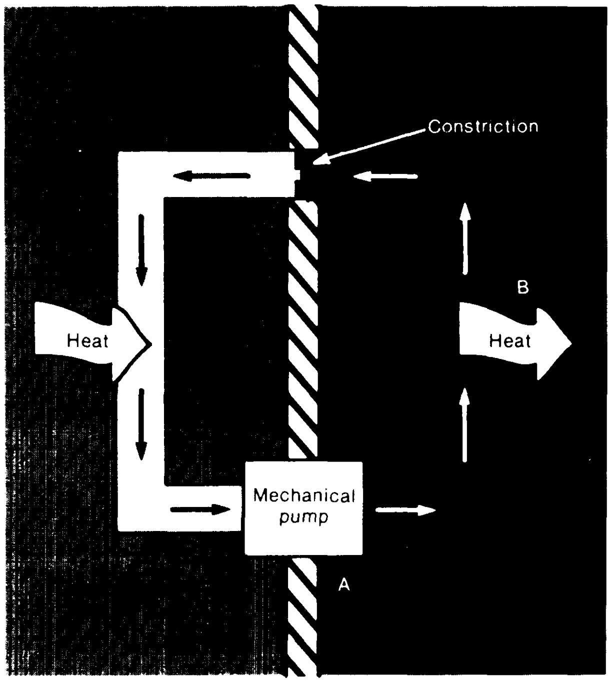
Several of the fuel switching technologies, such as conversion to natural gas, are widely understood and will not be considered i n this section. Others, however, require some explanation; and they are described below in order to provide an understanding of some of the factors that affect potential oil replacement through fuel switching.

Electric Heat Pumps

Heat pumps are devices for space heating[4] that are based on the fact that the temperature of many gases increases when they are compressed, and their temperature drops when they are decompressed. The heat pump works by circulating a gas through a tube that runs partly inside and partly outside of the building that is being heated (see **fig.** *18).* The gas is compressed in the part of the tube that is inside the building so that it is hotter than the inside air and releases heat to that air. The gas is decompressed in the part of the tube outside the building so that it is colder than and absorbs heat from the outside air. The net result is that heat has been transferred or "pumped" from the outside air to the inside air. (Obviously, by running the pump in reverse–compressing the gas in the tube outside of the building and decompressing it in the inside part of the tube-heat can be pumped out of the building, and the device becomes an air-conditioner,)

As long as the difference between the inside and outside air temperatures is not too great, a heat pump can pump more energy in the form of heat into a building than is consumed in the form of electricity to run the device. Its efficiency, or heat delivered to the inside air divided by the energy consumed to run the device, can then be greater than 100 percent. However, when the outside temperature drops, the efficiency also drops; and below certain outside temperatures, usually around *200* to 300 F, it is more efficient to use electric resistance heating (which has an efficiency of 90 to 100 percent). Consequently, heat pumps are usually equipped with electric

Figure 18.—Principle of an Electric Heat Pump



The function of most heat pumps is based on the fact that the temperature of most fluids rises when the fluid is compressed and falls when the pressure on the fluid is reduced,[a]

In the above diagram the fluid in the tube is compressed by a mechanical pump (A) as it enters the building. This raises the fluid's temperature to a level that is above the inside air temperature, causing heat to flow from the working fluid into the air inside the building (B), The fluid then passes through the constriction (C) as it leaves the building, causing the pressure on the fluid to drop. The apparatus is designed so that the pressure drop is sufficient to cool the fluid to a temperature which is below the outside air temperature, causing heat to flow from the outside air into the working fluid (D), The process is then repeated.

[a]A common **example of this occurs in bicycle** pumps. **When air** is **compressed in the pump to fill a bicycle tire, the air's temperature rises causing the pump to become hot**

SOURCE: Office of Technology Assessment.

resistance heaters, which are used when the outside temperature is low. Nevertheless, practical heat pumps, which are not designed to double as air-conditioners in the summer, can usually achieve an overall efficiency of about *200* percent. Designing heat pumps for both heating and cooling involves some design tradeoffs, which reduce overall heating efficiency to about 150 percent.

By way of comparison, oil heating has an efficiency of about 65 percent. Consequently, an ef-

[4]**Heat pumps can also be used for hot water heating, but only space heating is described here.**

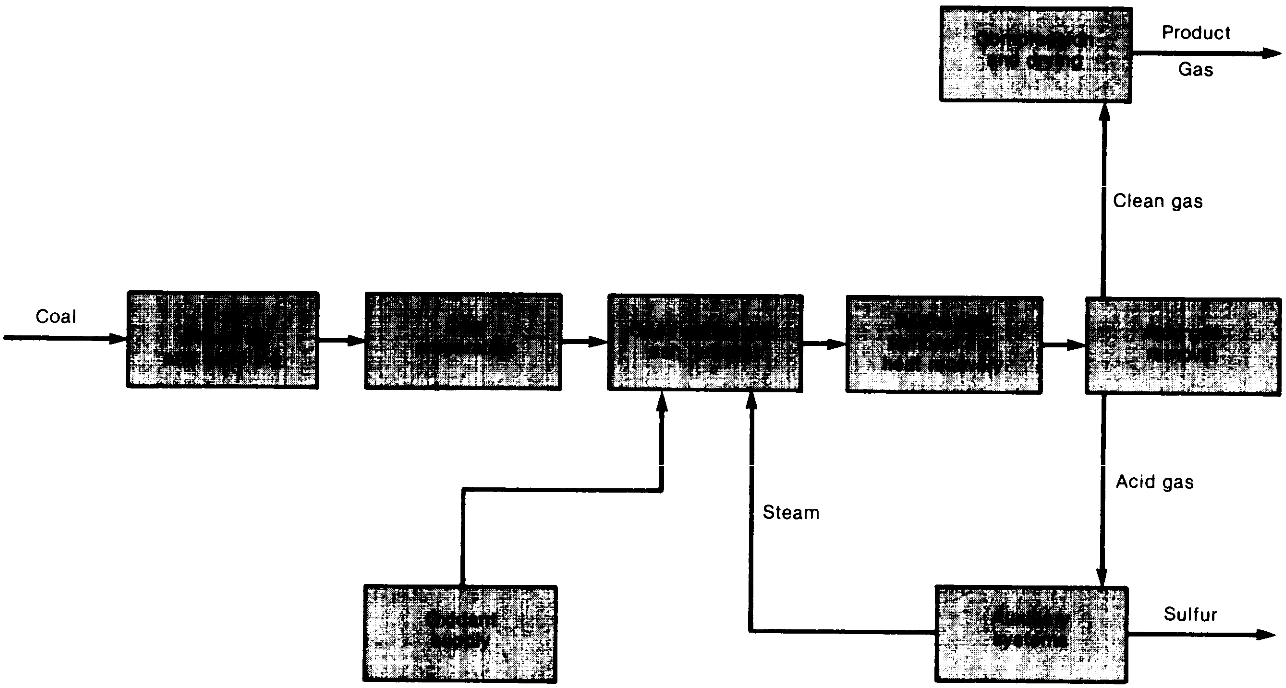
ficient heat pump requires about one-third as much energy (in the form of electricity) as an oil furnace requires (in the form of oil) to deliver the same amount of heat. As long as the electricity is generated from nonpremium fuels (i.e., coal, nuclear, or hydroelectric), the heat pump is an attractive alternative for replacing premium fuels. if, however, the electricity is generated with natural gas or oil, for which the efficiency of converting fuel to electricity is about 32 percent, this potential gain in premium fuel replacement is lost, since it would require at least as much oil or gas to produce the electricity as would be replaced by the heat pump. Consequently, in terms of oil replacement, heat pumps are attractive only where marginal electricity is generated from fuels other than oils

Conversion to Solid Fuels

There are three basic technologies considered for converting oil-burning boilers to use solid fuels (principally coal and wood). First, the boilers can be modified to burn the solid fuel directly. Second, the fuel can be gasified in an onsite, air-blown gasifier (see fig. 19). The gasifier partially burns the fuel to produce a low-energy fuel gas which is then burned in the boiler. Third, the boiler can be converted to burn coal-water mixtures (CWMS) (see fig. 20). These are mixtures containing up to 70 percent pulverized coal in water. Both direct combustion and gasification are commercial technologies, although further development probably could significantly im-

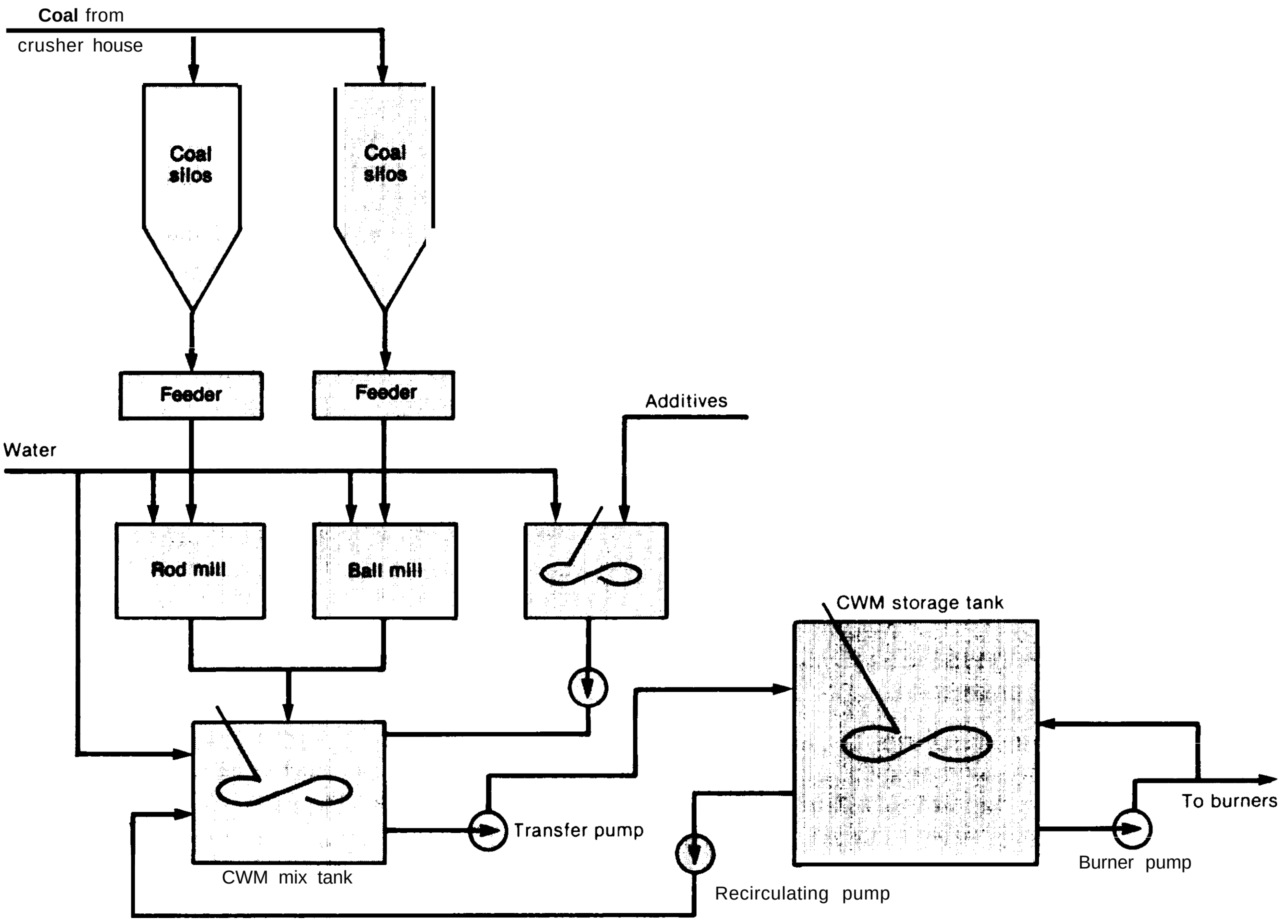
[5]If the oil used for electric generation is residual fuel oil, the situation is somewhat more complicated. Upgrading residual oil to middle distillates and gasoline is only about 70 percent efficient (Purvin & Gertz, Inc., "An Analysis of Potential for Upgrading Domestic Refining Capacity, " prepared for the American Gas Association, 1980). Consequently, in principle, some increase in the supplies of refined liquid fuels could be achieved by burning residual oil for electricity and using the electricity for heat pumps to replace home heating oil, as compared to simply upgrading the residual oil and using fuel oil for space heating. In practice, however, the region where oil use for electric generation is most likely to continue after an oil shortfall is in the Northeast, where the cold winters reduce the efficiency of the heat pumps. Consequently, burning oil to produce electricity for heat pumps would probably lead to a net increase in oil consumption in this region; and it would be, at best, a questionable strategy to promote heat pumps as a means of displacing oil there.

Figure 19.—Coal Gasification Plant—Block Flow Diagram



SOURCE: Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I—The Technologies," contractor report to OTA, April 1983.

Figure 20.—Schematic Flow Diagram of a Coal-Water Mixture Preparation Plant



SOURCE: Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I—The Technologies," contractor report to OTA, April 1983.

prove the gasifiers. CWM technologies are currently being tested, and they are likely to be commercial by 1985,

All three technologies require the installation of ash recovery and disposal systems and particulate control systems (to reduce particulate emissions) at the boiler site. Direct combustion and air gasification also require solid fuel storage and handling facilities at or near the boiler site. CWMs, however, can be prepared at off-site CWM plants. Because the CWM is a liquid, much of the oil storage and metering system can be used for the CWM after various valves and pumps have been replaced. This is a principal advantage of CWMs over the other technologies because it reduces the space requirements for conversion to the use solid fuel.

Converting boilers to solid fuels often leads to a derating of the boiler—i. e., the boiler's maximum steam output per unit time is reduced. This results from various combinations of: 1) the need to reduce the speed with which the combustion gases pass through the heat exchanger in order to reduce the abrasive effects of the ash contained in these gases, 2) lower flame temperatures, and 3) larger combustion gas volumes (as compared to oil or natural gas). Depending on the boiler design, the derating can range from negligible amounts to over **50 percent of the output before the conversion. Where the derating is large, con-**

version to solid fuels would be less attractive and the end users may require the installation of additional solid fuel boilers in order to make up the lost steam output.

In the utility sector, there are three basic types of boilers, and each type requires somewhat different modifications. First are the boilers that were originally designed for coal but were subsequently converted to oil. (These are usually the easiest to reconvert to coal and generally experience the smallest debating.) The oil-designed boilers are of two types, called type 1 and type 2. The type 1 boilers are similar to coal-designed boilers in terms of hearth configuration,[6] heat exchanger tube spacing, and other important factors; and these boilers can also be converted to solid fuels. However, type 2 boilers (about 35 percent of the oil-designed boiler population[7] require such extensive modifications that generally it is not practical to convert them. Consequently, for the purposes of this study, OTA has assumed that only the coal-designed and type 1 oil-designed utility boilers would be converted to solid fuels.

The population of industrial boilers has not been surveyed in the same detail as utility boilers. Consequently, OTA has simply assumed that 50 percent of the large (greater than 50 million Btu per hour (MM Btu/hr)) industrial boilers currently burning oil are suitable for conversion to solid fuels. Although there will be exceptions,[8] OTA also assumed that most of the small (less than 50 MMBtu/hr) industrial boilers would not be converted to solid fuels because of space limitations and the inconvenience and extra labor associated with solid fuel combustion.

Ethanol

Ethanol is a high-octane liquid fuel that can be used to fuel engines designed or modified for its use, or it can be blended with gasoline and the blends can be used in unmodified gasoline engines. Currently, the major use of fuel ethanol (about **500 million gallons per year) is as an octane-boosting additive to gasoline. These blends, which consist of 10 percent ethanol and 90 percent unleaded gasoline, were originally called "gasohol" but now are usually referred to as "premium unleaded gasoline with ethanol."**

Ethanol is currently produced from ethylene (a byproduct of oil refining) and from biomass. U.S. production of petrochemical ethanol was about 200 million gallons in 1981,9 almost all of which was used for chemical and pharmaceutical purposes. Although 1981 ethylene production (29 billion pounds[10]) would have been sufficient for 7 billion gallons of ethanol, using it to produce fuel ethanol would have diverted it from its higher value chemical uses. Consequently, this option has not been considered for fuel production.

Ethanol from biomass, the main source of fuel ethanol, is produced by fermenting a sugar solution and then distilling the solution to concentrate and purify the ethanol (see fig. 21). The sugar solution can be obtained from sugar crops, the starch in grains, or cellulose (contained in wood, plant herbage, the paper and wood in municipal waste, etc.). However, cellulose-derived sugar is relatively expensive because the processes either give low yields of sugar or consume large quantities of expensive chemicals and require expensive equipment.[11] The economics also generally favor the use of grain, principally corn, over sugar crops as the source of sugar in the United States, although there are site-specific exceptions to this.

A byproduct of producing ethanol from grain is a substance called "distillers' dry grain" (DDG), which contains most of the protein originally contained in the grain. The DDG can be used as a substitute for soybean meal and other protein concentrates in animal feeds. Above about 2 billion gallons per year of ethanol production, how-

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[6]Particularly the size of the hearth, which determines the length of time that the fuel remains in the combustion zone for a given air and fuel flow rate. Coal and wood react more slowly than does oil, so they require a longer residence time in this zone.

7"Survey of Oil-Fired Utility Boilers–Potential for Coal-Oil Mixture Conversion, " prepared by MITRE Corp. for U.S. Department of Energy, DOE/FE/531 79-01 UC-90E, July 1980.

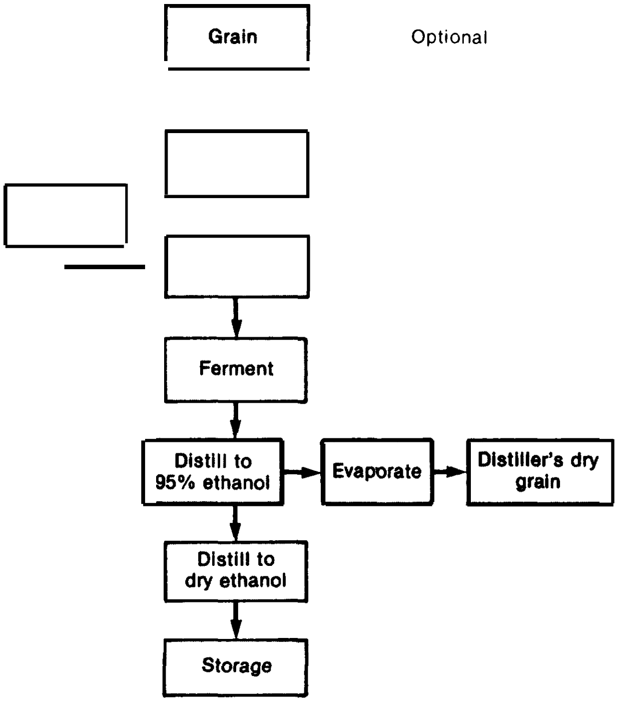
SR. Hodam, R. Williams, and M. Lesser, "Engineering and **Economic Characteristics of Commercial Wood Gasifiers in North America, " Hodam Associates, Inc., SER1/TR-231 -1459, November 1982.**

[9]*Chemical & Engineering News,* **June 14,** 1982.

[10]Ibid.

[11]*Energy* From Biological *Processes, Volume 11— Technical and Environment/ Analyses* **(Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-1 28, September 1980).**

Figure 21.—Process Diagram for the Production of Fuel Ethanol From Grain



SOURCE: Office of Technology Assessment

ever, the U.S. animal feed markets would begin to saturate; and this would have an adverse effect on the economics of ethanol production and increase the agricultural impacts of supplying the grain. (See "Fuel and Grain Supplies" below.)

Another concern is whether ethanol can replace more oil than is consumed in producing it–i.e., its net oil replacement. This involves three major areas: 1) distillery fuel use, 2) energy credits for ethanol's octane-boosting properties, and 3) grain production.

New, large-scale ethanol distilleries are generally fueled with coal, and their oil consumption is negligible. Experience to date, however, indicates that small, onfarm distilleries are usually fueled with oil;[12] and this is likely to result in distillery oil consumption that is at least half the energy content of the ethanol produced .11 Consequently, unless onfarm ethanol production is negligible or small-scale distillers begin to use solid fuels, distillery oil consumption could *re*duce the net quantity of oil replaced by ethanol significantly. For the purposes of this study, however, OTA assumes that most of the ethanol will be produced in large, coal-fired distilleries.

The second factor in ethanol's oil replacement potential involves its octane-boosting properties. Under more or less normal circumstances, addition of ethanol to gasoline enables the refiner to produce a lower octane gasoline and thereby reduce the refinery energy use. This energy "credit" typically amounts to 5 to 50 percent of the energy content of the ethanol .14 As discussed in appendix B of this chapter, however, changes in the product mix and processing needs at refineries following a large oil shortfall could reduce significantly or eliminate this energy credit. Consequently, OTA does not include a refinery energy credit when calculating ethanol's net oil replacement under conditions of a large shortfall.

The third factor is the fuel used to produce the grain, which is discussed in detail under "Fuel and Grain Supplies" below. When this agricultural energy use is included, the combined results indicate that ethanol production can, at best, lead to a net oil replacement equal to about half the energy content of the ethanol. And if the increased demand for grain leads to unfavorable (from an energy point of view) shifts in agricultural production and/or the distilleries are fueled with oil or natural gas, ethanol production will probably not reduce oil consumption and it could even lead to an increased demand for oil.

[12]"Fuel Alcohol on the Farm–A Primer on Production and Use," U.S. National Alcohol Fuels Commission, Washington, DC, 1980.

[13]Fuel consumption reported by the small-scale distillers is less than this, but the numbers reported probably do not include mash preparation, distillery sterilization, and DDG drying. OTA's estimate of the energy consumption is based on the best available technology for all the processes involved in ethanol fermentation and distillation; and inefficiencies in small-scale operations would probably increase their energy consumption above our estimate.

[14]*Energy From Biological processes, Volume II,* op. cit.

Compressed Natural Gas in Motor Vehicles

Compressed natural gas (CNG) can power existing automobiles and trucks if the fuel system is appropriately modified. Because natural gas is a high octane fuel, however, it is best suited for spark ignition (basically gasoline) engines. Currently, there are approximately 20,000 to 30,000 CNG-powered vehicles in the United States and 300,000 to 400,000 worldwide.[15 16] In addition, there are at least six suppliers of CNG conversions kits in the United States.[17]

Conversion of a vehicle to CNG is relatively simple and can be accomplished in less than 8 hours. It consists of installing cylinders to hold natural gas pressurized at 2,500 pounds per square inch (psi) together with the requisite fuel lines, valves, pressure regulators, and carburetor modifications to deliver the gas to the engine and to refuel (see fig. 22). Most vehicles are converted for dual fuel use so that they can run on either gasoline or CNG. Vehicles typically have a range of about 100 to 200 miles on CNG between refills.

Some other aspects of CNG vehicles are as follows:

- **Refilling.** The time needed for refills varies from 2 to 5 minutes on a fast-fill device (which requires a bank of high-pressure storage cylinders) to *4* to 14 hours on a slow-fill device (in which the vehicle is connected more or less directly to a compressor). A typical refill station might contain one fast-fill device together with several of the slower filling ones.[18]
- **Market.** Until there are a large number of CNG vehicles on the road, the most likely markets for CNG conversions are vehicles in captive fleets, where all of the fleet vehicles are refilled at a central location. This would maximize the use of the refill equipment and thereby lower the per-unit costs.
- **Engine power.** Because the engine in a dual-fuel vehicle is not optimized for CNG use, it develops 10 to *20* percent less power with CNG than with gasoline. When maximum power is required, however, the engine can be switched back to gasoline.
- **Safety.** Although there is always the potential for fires that are difficult to control and explosions if CNG fuel systems rupture, CNG vehicles have an impressive safety record to date. Of the estimated 1,360 collisions involving CNG vehicles in the United States, including 183 rear-end collisions, none caused a failure of or fire involving the CNG fuel system.[19] The safety record in Italy is also excellent. Nevertheless, this safety record could be reversed if designed safety margins were reduced in order to cut costs or lower the weight of CNG systems.

Liquefied Petroleum Gas in Motor Vehicles

Liquefied petroleum gas (LPG) is a mixture of light hydrocarbons extracted from raw natural gas at natural gas processing plants or produced as a byproduct of oil refining. Although the hydrocarbons are gases at atmospheric pressure and room temperature, they liquefy when subjected to moderate pressures (e.g., 150 psi), and the resultant LPG has an energy density (energy per unit volume) that is 72 percent as great as gasoline.

Precise estimates of the number of LPG-fueled vehicles in the United States are not available. The National LP-Gas Association estimates 1.5 million vehicles;[20] but calculations based on Energy Information Administration data for LPG used as an internal combustion fuel put the number at considerably less than 1 million.[21] Never-

15 "Compressed Natural Gas (CNG) Vehicle System Information Paper," Gas Service Energy Corp., Kansas City, MO, 1982,

16 "Assessment of Methane-Related Fuels for Automotive Fleet Vehicles," vol. 2, DOE/CE/501 79-1, U.S. Department of Energy, February 1982; and "State of the Art Assessment of Methane-Fueled Vehicles," DOE/CE-0026, U.S. Department of Energy, February 1982.

17 Ibid.

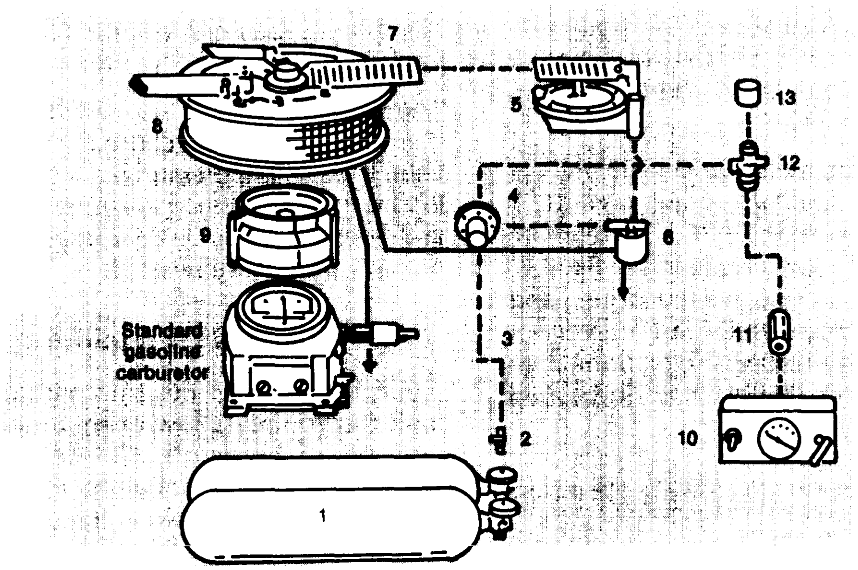
18 Gibbs & Hill, Inc. "Oil Replacement Analysis Phase I—Selection of Technologies," contractor report to OTA, April 1983.

19 Ibid.

20 P. Ayler, National LP-Gas Association, Oak Brook, IL, private communication to Gibbs & Hill, Inc., Oct. 29, 1982 and Nov. 3, 1982.

21 EIA ("Petroleum Supply Annual 1982," vol. 1, U.S. Department of Energy, DOE/EIA-0340(82)/l, June 1983) reports that, in 1982, 644 million gallons of LPG were used as fuel in internal combustion engines. Assuming that the average vehicle (van, truck, and car) gets 15 miles per gallon (mpg) of LPG and travels an average of 10,000 miles per year, the number of LPG-fueled vehicles would

Figure 22.—Components of CNG Vehicle Conversion



1. **CNG Storage Cylinders: CNG is stored on board the converted vehicle at 2,400 psi in the U.S. Department of Transportation 3AA rated cylinders.**
2. **Manual Shut-Off Valve: Each CNG storage cylinder is equipped with a high pressure ball valve which allows manual shut-off of CNG as an added safety feature.**
3. **Fuel Supply Line: The CNG supply line is made** of high pressure steel tubing with a minimum working pressure rating of not less than 3,000 psi and a test pressure rating of 12,000 psi. It is ¼" thick and is manufactured to Society of Automotive Engineers specifications.
4. **First Stage Regulator:** The primary regulator reduces CNG from 2,400 psi storage pressure down to 60 psi. It is tested to withstand pressures in excess of 15,000 psi.
5. **Second Stage Regulator:** The secondary regulator reduces CNG from 60 psi down to less than one pound working pressure. This regulator design has been used by the gas utility industry for many years and is rated for inlet pressures up to 125 psi.
6. CNG Solenoid **Valve:** A 12 volt DC pilot-operated solenoid, located between the first and second stage regulators, controls the flow of CNG into the system.
7. Vapor Hose: The vapor hose supplies CNG from the second stage regulator to the gas/air mixer. It is impervious to CNG and capable of sustaining five times the maximum service pressure.
8. **Gas/Air Mixer** This specially designed unit operates on the diaphragm controlled variable venturi principle. It meters CNG into the carburetor as required for combustion and maintains the proper fuel to air ratio at all levels of engine demand.
9. **Carburetor Adaptor:** This unit adapts the gas/air mixer to the standard carburetor in a straight-set or offset configuration.
10. **Fuel Selector Control Panel and Gauge:** The dash-mounted panel incorporates a sturdy push-pull cable with a handle for switching from one-fuel to the other. A pressure gauge indicates the amount of CNG remaining in the vehicle.
11. Gauge Isoiator The isoiator is installed in the high pressure fuel supply line behind the pressure gauge to prevent CNG from entering the passenger compartment.
12. **Combination Valve:** The combination check and fill valve allows CNG to flow through the fuel supply line to the storage cylinders and functions as a relief device to guard against overpressurization. It also automatically seals the system after refueling.
13. **Refueling Connection:** The refueling connection is designed to receive **a** probe-type refueling coupling and is equipped with an interlock switch to prevent the vehicle from being started inadvertently during refueling.

SOURCE: "The Dual Fuel BiPac System — Vehicle Conversion," Dual Fuel Systems Inc., Culver City, CA, 1981

theless, there have been reports that as many as 300,000 vehicles were converted to use LPG in 1981.[22] Furthermore, Ford Motor Co. began selling LPG-fueled cars in 1982, and they expect their 1982 sales of 1,500 vehicles to rise to 6,000 in 1983.[23]

Converting a gasoline-fueled vehicle to LPG entails installing an LPG fuel tank, fuel lines and filter, a device to vaporize the LPG and regulate the gas pressure, and a gas air mixer (see fig. 23). The conversion can be done in a few hours, and the converted vehicles generally can burn either gasoline or LPG. Furthermore, the National Fire Protection Association (NFPA) has developed standards governing the installation procedures and major LPG fuel system components, and the National LP-Gas Association has a program that certifies installers to the NFPA standards.

Refueling with LPG is somewhat more complex than with gasoline, because the filling station and vehicle tanks are pressurized. However, because LPG is liquid and the pressures involved are not great, refueling can be done quickly and presents no unusual difficulties.

Mobile Gasifiers

Gasifiers are devices that partially burn solid fuels to produce a low-energy fuel gas. For the purposes of this report, OTA defines mobile gasifiers as gasifiers attached to motor vehicles in which the fuel gas powers the vehicle. The gasifier can be mounted directly to the vehicle–e.g., on a bumper, inside the vehicle shell, in a truck's bed–or it may be mounted on a trailer drawn behind the vehicle.

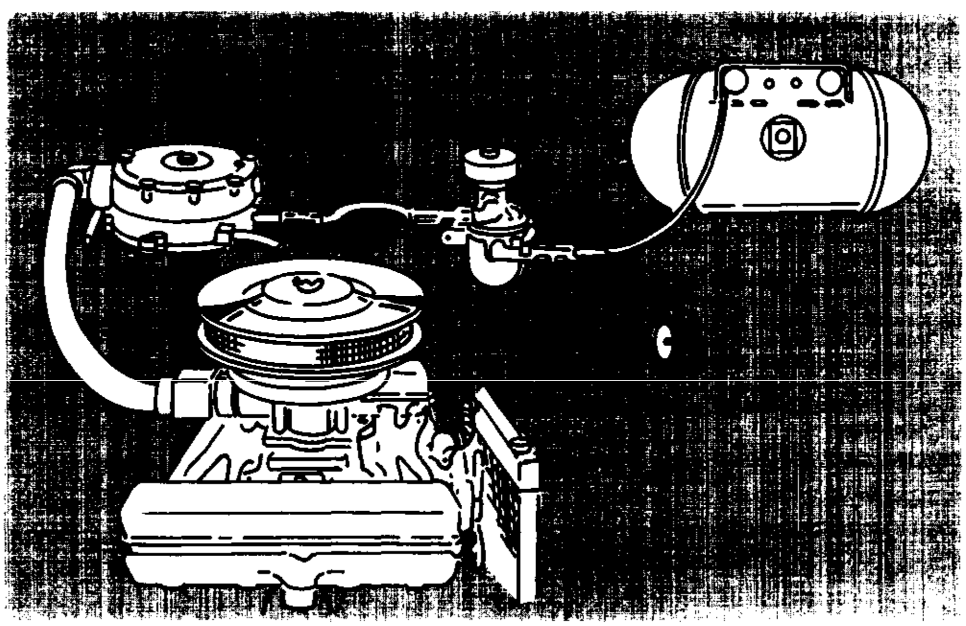
During World War 11, mobile gasifiers were used in several industrialized countries, including England, France, Italy, Germany, Sweden, and Japan. By 1943 there probably were several hun-

be about 966,000. However, some of this LPG is used for stationary engines, the 15 mpg average fuel efficiency is probably too high, and 10,000 miles per vehicle year may be too low. All of these potential errors would tend to exaggerate the number of LPG-fueled vehicles. In fact in its Annual Report to Congress, EIA lists LPG use in transportation at 0,01 quad/yr or 110 million gallons. This would put the number of transportation vehicles at perhaps 170,000; but other vehicles in construction, mining, and agriculture would increase the total.

[22] "Vehicle Conversions to LP-Gas Fuel: Is It Worth It?" *Public Wok,* June 1982.

[23] 'Ford Introduces a Gas Burner, " *Machine Design,* Apr. 22, 1982; and R. J. Nichols, Ford Motor Co., communication to Gibbs & Hill, Inc., Mar. 17, 1983.

Figure 23.—Components of LPG Vehicle Conversion



SOURCE: "Vehicle Conversion to LP-Gas Fuel: Is It Worth It?," Public Works, January 1982 dred thousand (and perhaps as many as 1 million) vehicles fueled by gasifiers.[24] Nevertheless, additional development is required in order to optimize designs for modern vehicles and to establish design standards, but this does not present any serious problems. Consequently, while mobile gasifiers are not a commercial technology at present, there are no fundamental barriers that would prevent them from becoming commercial within a relatively short time.

A typical gasifier fuel system would consist of the gasifier, heat exchanger to cool the fuel gas,[25] a filter system to remove particulate from the gas, tubing to deliver the gas to the engine, and a device to mix the gas with appropriate quantities of air before it enters the engine (see fig. 24). In most cases, the gasifier system would be installed in a way that would allow the engine to run either on petroleum or on the fuel gas. In gasoline engines, the fuel gas would be ignited by the engine's spark plugs, and no gasoline would be necessary when the gasifier is operating. For diesel engines, however, small amounts of diesel fuel would have to be injected in order to ignite the fuel gas; and modifications to the diesel injection system might be necessary to limit the power output at full throttle so as to avoid excessive engine wear. The installation and any necessary

[24] Rasor Associates, Inc., "Evaluation of Mobile Gasifiers for the OTA Oil Replacement Analysis Project," contractor report to OTA, July 1983.

[25] The gas has to be cooled to increase its energy density and to prevent misfiring. Without gas cooling, engine performance would not be acceptable.

modifications, however, could probably be completed in one day.

The size of the gasifier will depend on the power and driving range needed, but the gasifier for an average passenger car might be a cylinder that is about 1.5 ft in diameter and 4 ft long. Such a gasifier would provide a driving range of about 300 miles on coal or 75 miles on wood.[26] The heat exchanger and filter would be somewhat smaller than the gasifier and might typically be the size of the vehicle's radiator. Other designs are both possible and likely, however.

After the ash is removed and the gasifier is filled with fuel, the fuel is ignited with a small flare. Air then must be drawn through the gasifier for 2 to 5 minutes before the exhaust gas can be ignited, and full power does not develop until after about 20 minutes of operation. Even with full gasifier output, however, the power of the vehicle engine would be less than 60 to 70 percent of its power when operating on gasoline, or, in the case of a diesel engine, about 80 percent of the power (if diesel injection is minimized). In addition, the gasifier operates best when its power output is reasonably constant and it responds slowly (relative to gasoline engines) to changes in power requirements. Although petroleum fuel could be used when the engine is first started and when full power is needed, the limitations of gasifiers indicate that they are best suited to long trips with relatively stable power needs, such as in intercity driving.

[26] Rasor Associates, Inc., op. cit.

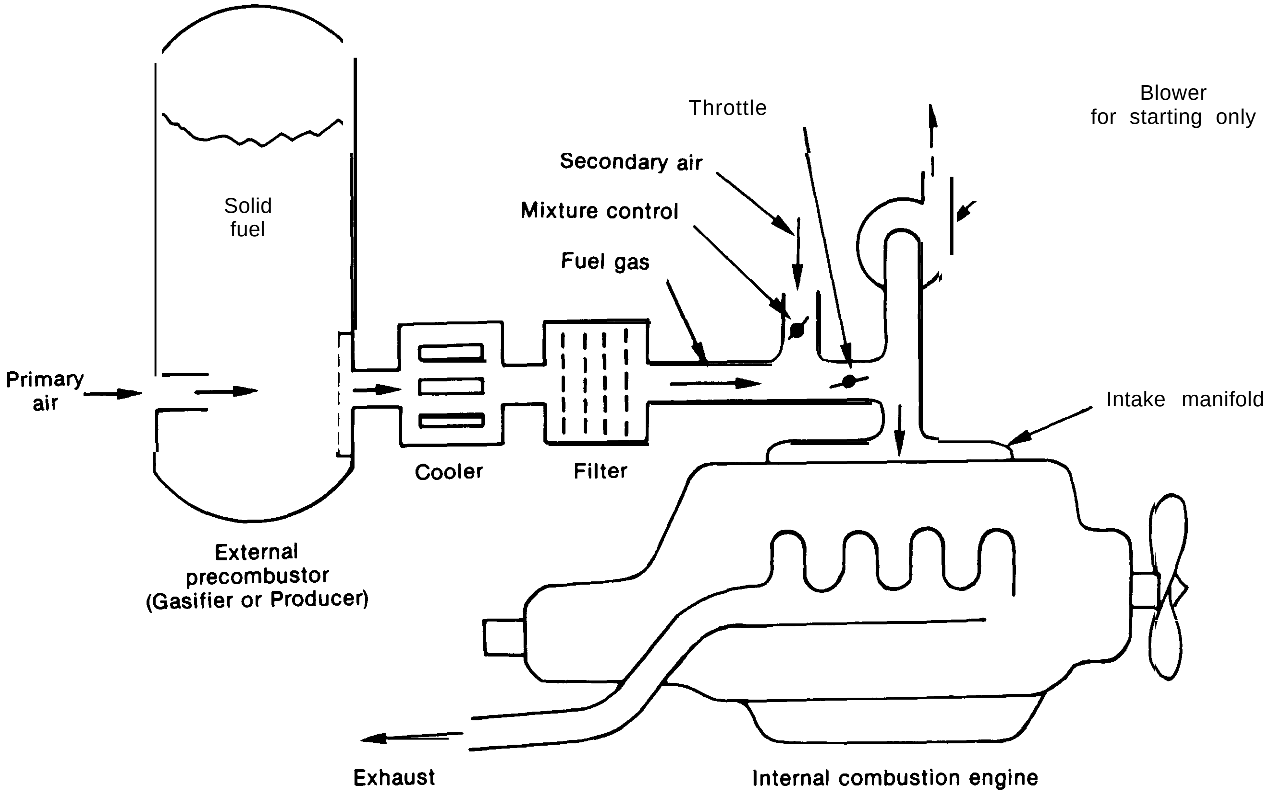
FUEL AND GRAIN SUPPLIES

Following the postulated oil shortfall, there will be an increase in conventional oil and gas exploration and development. Enhanced oil recovery projects started before the shortfall will begin to produce, and any surge production capacity will be utilized to maximize domestic oil production.

OTA has not assessed the potential quantities of oil from these sources, but has assumed that these activities will, at best, keep domestic oil production constant during a 5-year period following the onset of a shortfall. To the extent that actual production differs from this assumption, it would be roughly equivalent to a less or more severe oil shortfall.

Beyond this assumed baseline for domestic oil production, several other fuel sources have been identified for more detailed study as replacements for the petroleum lost in an oil shortfall. Domestic oil production can be increased (relative to

Figure 24.– Basic Elements of the Mobile Gasifier-Engine System



SOURCE: Rasor Associates, "Evaluation of Mobile Gasifiers for The OTA Replacement Analysis Project," Contractor report to OTA, February, 1983.

what it otherwise would have been) through new enhanced oil recovery (EOR) projects. Oil users can also switch to natural gas, coal, and solid biomass fuels. And grain can be used as a feedstock, together with coal or solid biomass as a fuel, for ethanol production.

The more detailed analysis of these options, however, indicates the following: Supplies of solid fuels are likely to be adequate. The supplies of natural gas are uncertain, but it is reasonable to assume that around 2 trillion cubic feet per year (TCF/yr) could be available for fuel switching. On the other hand, although EOR can produce significant quantities of additional oil in the time period of 5 to 10 years after the onset of an oil shortfall, its contribution within less than 5 years is doubtfu1, due to the long leadtimes before enhanced production actually materializes. And, although adequate quantities of grains could be supplied well before ethanol distilleries could be built, the resultant increased use of energy by agriculture would greatly reduce the net oil replacement from ethanol.

Potential supplies of each of these fuels and grain are discussed in more detail below. In addition, where it is an important factor, the interdependence of fuel supplies is also considered. Availability of electricity is not considered in this section, however, because it depends heavily on construction and fuel switching plans of electric utilities, and it more properly fits into the following section on fuel switching.

Coal

Based on the analysis presented in the section on fuel switching, full implementation of the fuel switching options, including the use of coal-water mixtures and direct coal firing in utility and industrial boilers, would increase coal consumption by up to 115 million tons/yr. Up to 20 million additional tons/yr could be used for new EOR projects. OTA assumed that to prevent an increase in sulfur emissions without the use of flue gas desulfurization, those who switch from oil to coal would use low-sulfur coal (less than 1 percent sulfur), which would account for 65 million tons/yr of the increase in coal use. The remaining increase would be in new coal-fired powerplants and for increased electricity production in existing powerplants, together with smaller amounts for space heating and hot water.

In 1978, U.S. coal production was 665 million tons,[27] of which 219 million tons contained less than 0.8 percent sulfur and 143 million tons contained 0.9 to 1.2 percent sulfur.[28] Consequently, over 40 percent of the total shipments contained less than 1 percent sulfur. Of this low-sulfur coal, about half was eastern coal.[29] By 1982 coal production had grown to 833 million tons, with 707 million tons consumed domestically and, although explicit data are not available, the proportion of low-sulfur coal and low-sulfur eastern coal was probably similar to the 1978 data. Furthermore, in 1974 the U.S. Demonstrated Reserves Base[30] of low-sulfur coal amounted to about 200 billion tons, of which 33 billion tons were estimated to exist in Appalachian and Midwestern coal fields. More recent studies[31] indicate that recoverable reserves (the most restricted category) of Appalachian low-sulfur coal amount to 14 billion tons. Consequently, although low-sulfur coal production would have to increase by about 25 to 30 percent to meet the maximum projected demand, coal supplies appear to be adequate; and, if necessary new mines could be opened well within the 5-year time period.

Wood and Other Solid Biomass

Potential supplies of wood and other solid biomass show large variations from region to region. Wood supplies are greatest in the South, Great Lakes region, and the Northeast, with lesser supplies in the Pacific and Rocky Mountain regions. The potential for energy from crop residues is concentrated in the agricultural regions of the Midwest, South, and Pacific coast regions. Potential supplies of forage grasses are mainly in the regions east of the Mississippi River.[32] Supplies of municipal solid waste are, of course, largest in the large metropolitan areas.

Wood is currently the largest source of energy from solid biomass in the United States. Potential future supplies of wood also appear to be considerably larger than those of crop residues, grasses, and municipal solid waste taken together; and the technologies for using wood are more widely disseminated and better understood than those for the other sources of solid biomass. Consequently, of these sources, wood appears to have the greatest potential for displacing petroleum during an oil shortfall in this decade.

If harvested as part of an integrated forest management program, the potential wood energy supplies in each region are more than adequate to supply the projected incremental demand for all solid fuels (including coal) as replacements for oil, although individual States may have to import from neighboring States. (See fig. 25 for the Standard Department of Energy regions used in this report and table 8 for wood energy potential by region.) The tightest supplies would be in the New York/New Jersey region, where the incremental demand for solid fuel could be about equal to the potential wood supply; but additional wood could be imported from regions 1 and 3, which have the potential for large surpluses. if the wood is harvested in a haphazard manner, however, supplies would be considerably smaller (following initial clearing of existing forests), wood energy markets could divert commercial timber (used for lumber and paper pulp) from the forest products markets, and environmental damage could be extensive.

In practice, market confusion surrounding a rapid growth in demand for wood would be likely to cause at least temporary shortages of wood in numerous locations. However, since wood (and

[27] Of Which 4 percent went to exports and 11 percent were for coke plants.

[28] "Sulfur Content in Coal Shipments 1978," DOE/EIA-0263(78), June 1981.

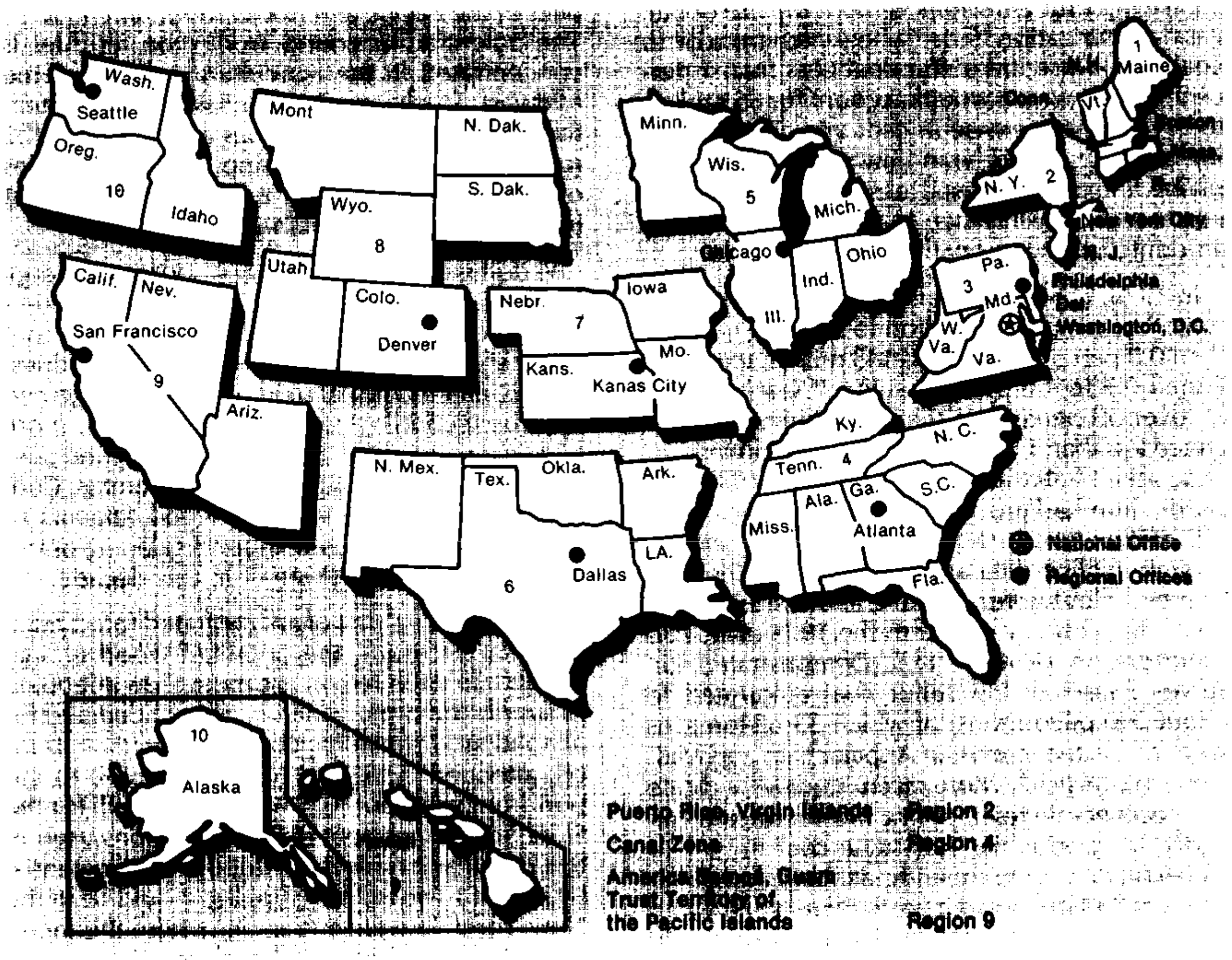
[29] Ibid.

[30] The Demonstrated Reserve Base represents the amount of coal contained in coal beds that meet certain criteria of geological assurance, depth, and seam thickness.

[31] R. L. Carmichael, "Report on Recoverable Reserves and 1978 Production of Low Sulfur Bituminous Coal Fields in the Eastern States," Oak Ridge National Laboratory for U.S. Department of Energy, January 1981.

[32] *Energy From Biological Processes* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-124, July 1980).

Figure 25.—Federal Regions



SOURCE: U.S. Department of Energy

Table 8.-Potential Wood Energy Production by Region, Assuming 10 Quadrillion Btu/Yr Increment

Region	Quantity (10^{15} Btu/yr)
1	0.68
2	0.36
3	1.0
4	2.8
5	0.88
6	1.2
7	0.22
8	0.57
9	0.52
10	1.76
Total	10.0

SOURCE: Office of Technology Assessment.

other solid biomass) would be competing with coal for the available markets, it is likely that wood use would be concentrated primarily in locations where the potential supplies are very much larger than the demand, such as in heavily wooded areas. Thus, it is highly unlikely that the availability of wood or other solid biomass would constrain the deployment of technologies for replacing oil with solid fuels.

Natural Gas

The American Gas Association recently estimated that the United States currently could produce about 2.7 TCF/yr more natural gas than the 18 TCF/yr consumed in 1982.[33] OTA's assessment of natural gas availability,[34] however, indicates that future supplies are extremely uncertain. Consequently, rather than attempting to derive a highly uncertain estimate, OTA has assumed that there will be a 2 TCF/yr of natural gas available to replace oil. (This amount of gas is equivalent in energy content to 1 MM B/D of oil.) To the extent that this gas is not available from domestic production (including unconventional sources) and various domestic conservation measures, OTA assumes that imports from Canada and Mexico can be increased to provide the supply. It should be noted, however, that feasible increases in efficiency of natural gas use in the industrial, residential, and commercial sectors, could replace about 2 TCF/yr of gas currently being used in those sectors (see ch. V). Consequently, if domestic production can be kept constant and the efficiency changes are implemented, this supply of gas would be available without increased imports.

Because natural gas availability is assumed to be limited, it is necessary to postulate how it will be allocated among the various consuming sectors. To do this OTA first assumed that the residential/commercial sectors would have priority over the other sectors for the use of natural gas. Based on this assumption, OTA found that about 0.9 TCF/yr could be used in the residential and commercial sectors for heat and hot water. The remaining 1.1 TCF was then distributed between the industrial and utility sectors in proportion to amount of oil they would be consuming after feasible conversions to coal had been completed. This resulted in an allocation of 0.9 TCF/yr to the industrial sector[35] and 0.2 TCF/yr to electric utilities.

Liquefied Petroleum Gas

Increased domestic production of natural gas would also lead to increased supplies of liquefied petroleum gas (LPG) from natural gas plant liquids (NGPL). In 1981, NGPL production was about 11 percent of natural gas production, on an energy basis.[36] Newly discovered supplies of natural gas generally contain less NGPL, however. Assuming that the new gas production is 9 percent NGPL, that 60 percent of the NGPL is LPG, and that *75* percent of the LPG is suitable for internal combustion engines, an increase of *2* TCF/yr in natural gas production would result in an additional 0.04 MM B/D oil equivalent of LPG suitable for engines. This would also result in 0.05 MMB/D oil equivalent of NGPL and LPG not suitable for engines, but which could be used for some stationary fuel purposes. To the extent that the natural gas is made available through increased efficiency of natural gas use, however, less incremental LPG would be available.

Enhanced Oil Recovery

The total amount of oil recovered from some oil fields can be increased through enhanced oil recovery (EOR). The process consists of injecting a fluid (generally carbon dioxide (CO_2) or steam) into an oil field through a series of injection holes. Approximately 2 years after injection begins, oil production from the field starts to increase,

Two areas of the United States that are major candidates for EOR are Texas and California. In Texas the fields would be injected with CO_2 that could come from natural CO_2 fields in Colorado and New Mexico and the recovery of CO_2 from the effluents of chemical plants (notably ammonia plants) and, possibly, electric powerplants. The leadtime for constructing the necessary equipment and pipelines and drilling the injection holes is about *2* years[37] (see fig. 26).

[33]"Natural Gas Production Capability in 1983, " American Gas Association, May 27, 1983.

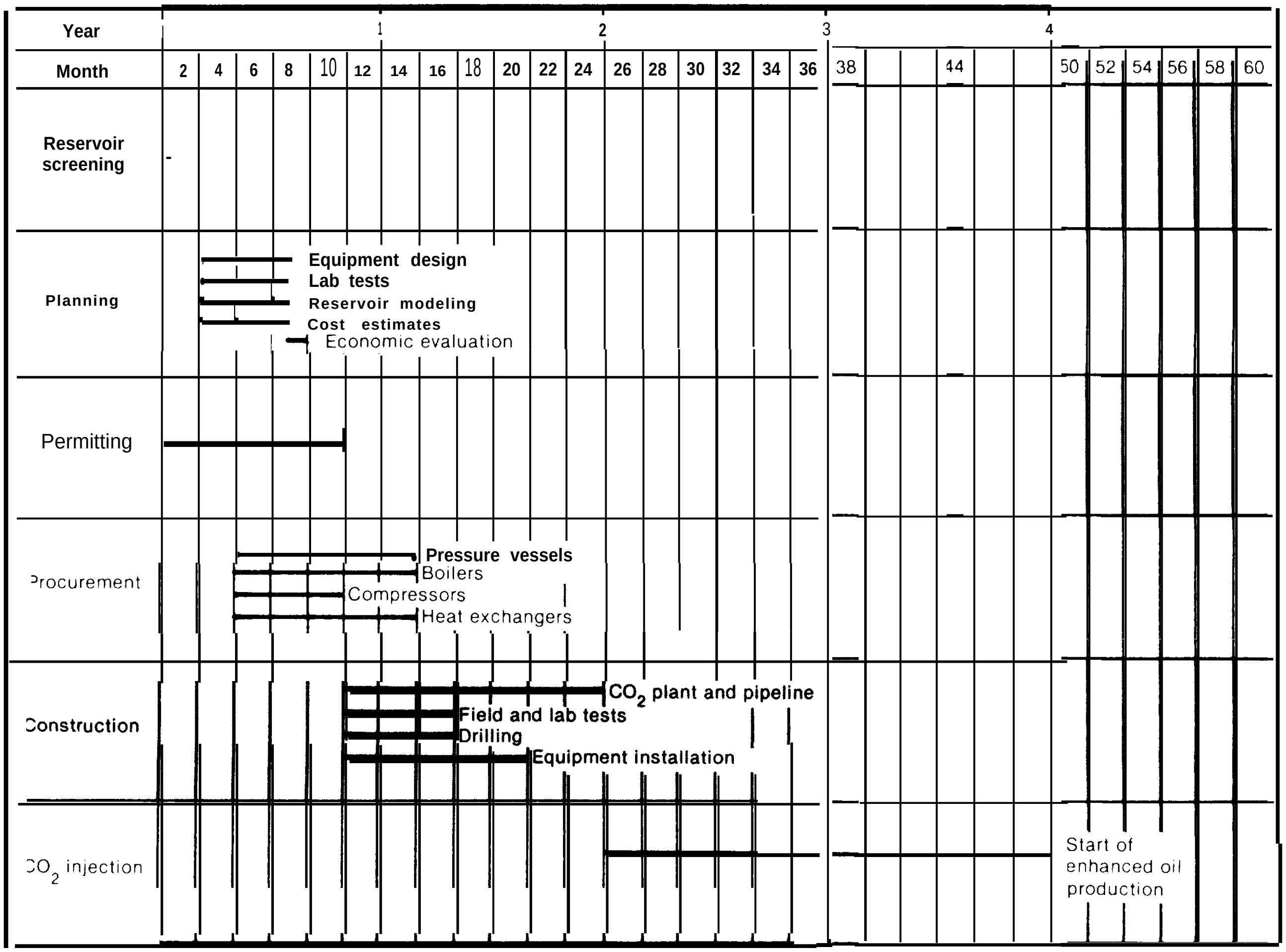
[34]*U.S. Natural Gas* Availability: *Conventional Gas Supply Through the Year 2000-A Technical Memorandum* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-TM-E-12, September 1983).

[35]If 5 billion gal/yr of ethanol are produced (with an energy equivalent of 0.2 MMB/D), then natural gas use for fertilizer production would increase by about 0.05 MMB/D. Although this gas use would decrease the amount of gas available for other uses in the industrial sector, use of the ethanol would free up some additional 011 that could be used in the industrial sector. By using a net energy approach (i.e., assuming that this ethanol would lead to a net reduction in oil consumption equal to 0.1 MMB/D), this Increased agricultural use of gas as well as oil is accounted for; and no inconsistencies are introduced by adding the oil replaced by ethanol (O. 1 MMB/D) to the industrial oil replaced by gas (0.9 TCF or 0.45 MM B/D).

[36]"Petroleum Supply Annual, " op. cit.

[37]Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II—Evaluation of Selected Tech nologies,' contractor report to OTA, August 1983.

Figure 26.—Schedule for Accelerated EOR CO_2 Flooding Project



SOURCE Office of Technology Assessment

In California, steam would be injected, The leadtime for erecting the boilers and other equipment and drilling the injection wells would be about 1¾ years without flue gas desulfurization (scrubbers) and at least 2½ years with scrubbers[38] (see fig. 27).

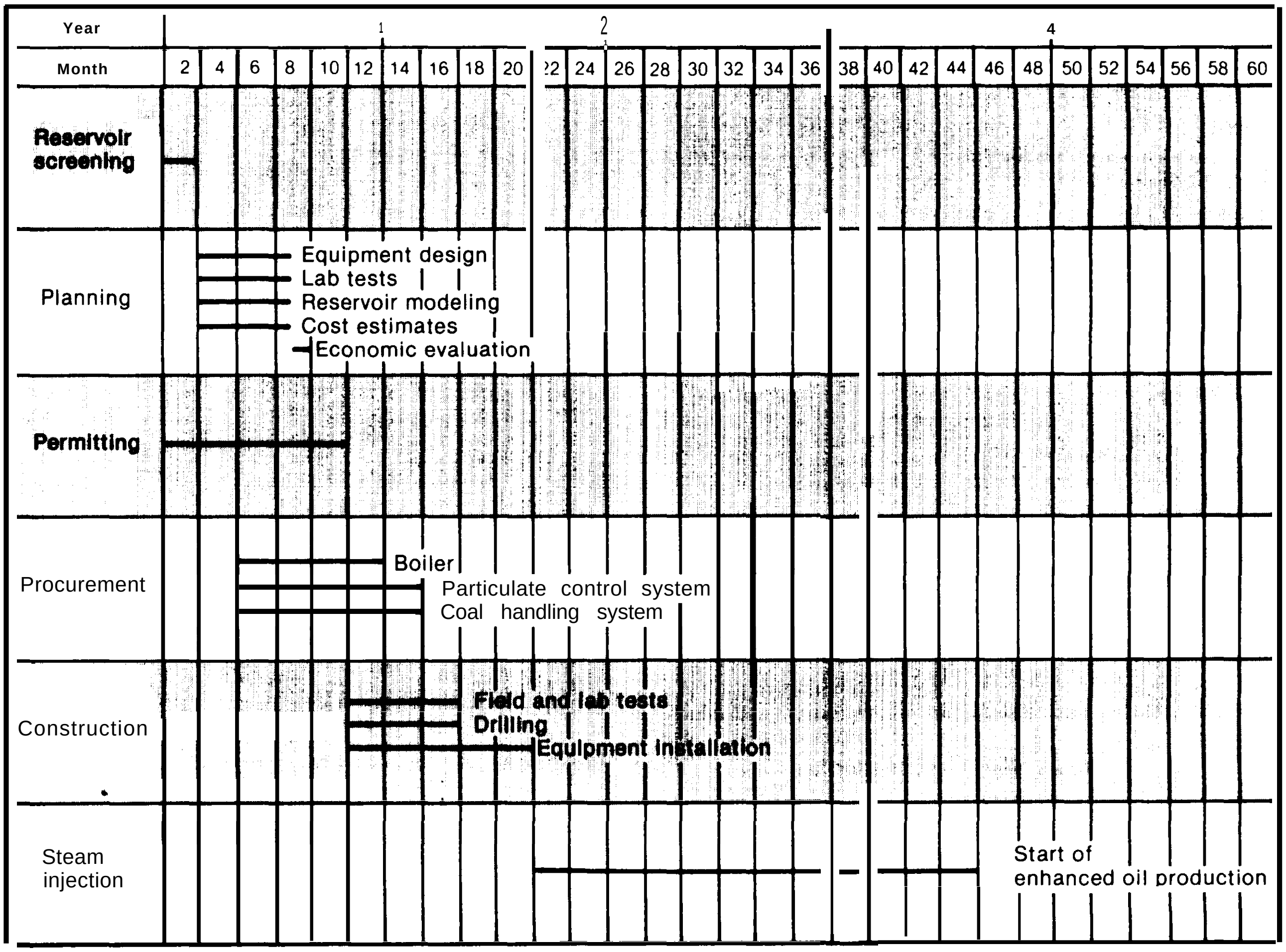
With the time required for construction and the delay before enhanced recovery materializes, at least 4 years would be required before any additional oil could be produced through new EOR projects. Once enhanced production begins, however, it could increase rapidly to as much as 0.8 MMB/D within a year, as illustrated in figure 28. If oil rather than coal is used to produce the steam in the California EOR projects, as is now the practice, net oil production would be reduced by over 0.1 MMB/D.

Numerous complications could easily delay these projects by a year or more, however. In Texas there could be delays in securing cooperative agreements with electric utilities and chemical plants and in securing rights of way for the pipelines. In California virtually all of the production would occur in Kern County, where the current levels of sulfur dioxide (SO_2), carbon monoxide, particulate, and oxidants in the air all exceed the ambient air quality standards (AAQS).[39]

[38]Ibid

[39]Frank T. Princiotta, Director, Industrial Environmental Research Laboratory, U S. Environmental Protection Agency, Research Triangle Park, NC, private communication, July 8, 1983.

Figure 27.—Schedule for Accelerated EOR Steam Flooding Project



SOURCE: Office of Technology Assessment.

Furthermore, the ambient nitrogen oxide (NO,) level is about 95 percent of the AAQS.[40] Consequently, permitting delays are likely, particularly if a large number of projects are started simultaneously. in addition, the EOR projects will have to compete with the industrial oil users that are switching to solid fuels for much of the equipment they will need and they will have to compete with conventional oil and gas exploration and development for drilling rigs.

Because of the long leadtime before enhanced oil production begins and because of the possibilities for delay, the potential for new EOR projects within 5 years after the beginning of an oil shortfall is highly uncertain. In OTA's judgment, these characteristics of EOR put it more nearly in the category of long leadtime technologies with high production potentials, such as synfuels, than in the area of short-term responses, which are being emphasized in this assessment. Therefore, potential oil production from new EOR projects is not included as one of the short-term responses in this assessment; although it, together with fossil synfuels, could provide large quantities of liquid fuels in the time period of 5 to 10 years or more following an oil shortfall.

'01 bid.

Grain

OTA's analysis of ethanol production indicates that distilleries capable of producing up to almost **5 billion gal/yr of ethanol (about 0.2 MMB/D**

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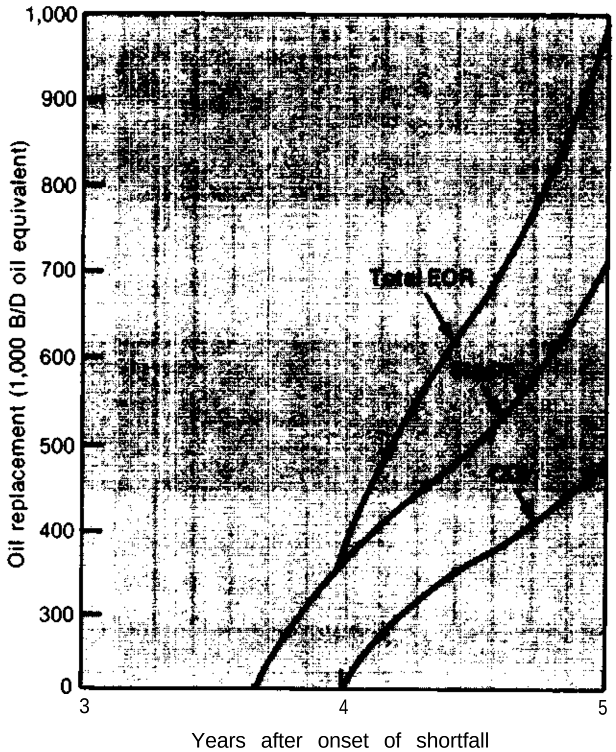
Figure 28.—Potential Oil Production Rate for Enhanced Oil Recovery



SOURCE: Office of Technology Assessment

Photo credit: U.S. Department of Energy

Fuel ethanol is produced from corn in this large distillery in central Illinois

energy equivalent) could be constructed within 5 years after the onset of an oil shortfall. These distilleries would require about so million tons of grain or 2 billion bushels of corn per year.

In 1981, U.S. grain production was about 333 million tons, of which 55 percent was for domestic use and 45 percent was exported. Corn production in that year was 8.2 billion bushels, up from an average of about 7 billion bushels per year during the previous few years. Therefore, supplying the feedstocks for 5 billion gal/yr of ethanol production would require about a 15-percent increase in grain production or a 30 percent increase in corn production.[41] With the appropriate price incentives and government policy (within the authority contained in existing, legislation), agricultural production of conventional grains could almost certainly increase by these amounts well before the distilleries could be built.[42]

If the ethanol is derived from corn, a byproduct of the conversion process is distillers' dry grain (DDG), gluten, or some other such protein concentrate, which can be used to replace the soybean meal used as a protein supplement in animal feeds. Consequently, soybean production could be reduced somewhat; and, for 2 billion gal/yr of ethanol production, the net increase in cropland under cultivation would be considerably less than 5 million acres. Beyond about 2 billion gal/yr, however, the soybean meal markets would begin to saturate; and a total of at least

[41]Assuming that average corn yields on the marginal land are 70 bushels per acre and that they are fertilized with 150 lb/acre of nitrogen, 35 lb/acre of phosphorus, and 100 lb/acre of potassium, then nitrogen, phosphorus, and potassium production would have to increase by about 20, 9, and 32 percent, respectively ("Agricultural Statistics 1981," U.S. Department of Agriculture, 1981). This can probably be accommodated within the 5-year timeframe, however.

[42]On the other hand, rapid increases in the production of crops that currently have low production volumes could be constrained by the availability of seed or other material (e.g., shoots, seeding tubers) needed to plant the crop.

20 million acres of new cultivation would be required to satisfy corn demand for the production of 5 billion gal/yr of ethanol.[43]

With this level of increase, one would expect significant shifts in the quantities of agricultural commodities produced in the various regions; and with it there could be subtle, though significant, changes in agricultural energy use. Furthermore, oil refinery operations and needs would change during the postulated oil shortfall; and this would affect the energy credits that could be ascribed to ethanol for its octane-boosting properties under more normal circumstances. These effects are discussed in more detail in appendix B to this chapter.

The net result is that after changes in agricultural energy use are accounted for, production of 5 billion gal/yr of ethanol (energy equivalent of 0.2 MMB/D of oil) could result in anywhere from a 0.15 MM B/D reduction to a 0.12 MM B/D **increase** in oil consumption. The former would occur if only minimal shifts in agricultural production from one region to another occur and there is a surplus of natural gas (used to produce farm fertilizers and pesticides). The latter would occur if there are modest, but unfavorable (from an energy point of view) shifts in agricultural production and there is no surplus of natural gas (so that use of this fuel in agriculture limits the switching from oil to gas in other sectors).

In OTA's opinion, it is unlikely that there would continue to be surpluses of natural gas several years after the onset of the oil shortfall. And increasing corn production by the quantities needed for 5 billion gal/yr of ethanol synthesis would almost certainly lead to some interregional shifts in agricultural production, such as in the example given in appendix B. Consequently, OTA considers it highly unlikely that production of 5 billion gal/yr of ethanol from corn could replace more than 0.1 MMB/D of oil; and it is possible that it would replace 0.05 MM B/D or less. (See box on Calculating Ethanol's Energy Balance.)

Use of significant quantities of other grains as feedstocks would differ from the use of corn in two respects. The oil and gas used to grow a given amount of grain could vary from 20 to 25 percent less than corn (e. g., wheat, oats, barley) to about 15 percent more than corn (e. g., grain sorghum). But in all cases, the yields per acre cultivated are significantly less than that for corn, and the amount of cropland under cultivation would have to increase proportionately more. Depending on how the agricultural system adjusted to this new demand, the net oil replacement (per gallon of ethanol) from other grains could range from about the same as to significantly less than that from corn.

Consequently, although the agricultural system could supply the grain needed for the maximum levels of ethanol production that are technically feasible within 5 years after an oil shortfall, the increased energy consumption in agriculture would greatly reduce the potential oil replacement.

[43]Note that this additional acreage cannot be accommodated solely with existing set-aside acreage, Additional set-aside acreage would be needed in order to stabilize year-to-year fluctuations in grain prices and in order for the corresponding farm price support programs to function. In fact, because the crop yields from the additional acreage under cultivation would fluctuate more from year to year than does average cropland, the average amount of set-aside acreage probably would have to increase in order to maintain the same overall stability in grain prices as exists now.

DEPLOYMENT OF FUEL SWITCHING TECHNOLOGIES

The above analysis indicates that, with the exception of natural gas, fuel and grain supplies are not likely to limit the deployment of the major fuel switching technologies studied. In the case of natural gas, future supplies are too uncertain to make a definite judgment.

In this section, end-use equipment and, where appropriate, fuel delivery systems are examined in order to estimate the rate at which they can be installed and the oil replaced. The general procedure is to estimate the market penetration of each technology and determine the equipment and manpower needed to deploy that technology. Potential deployment rates are then estimated by comparing the equipment and manpower needs to historical production and fuel switching data and industry estimates of what could be accomplished in a crisis.

The starting point for this analysis is OTA's estimate of 1985 oil consumption by end-use category and sector. These estimates are shown in table 9 and are broken down into the Department of Energy regions shown in figure 25. The estimates are based on Energy Information Administration (E IA) projections[44] and data,[45] OTA's assessment of automobile fuel efficiency,[46] and OTA's judgment.[47]

Several categories of oil use are not included explicitly in table 9, because it would be particularly difficult to switch from these oil uses to alternatives within the 5-year time period considered in this assessment. These include aviation and marine fuels, petrochemical feedstocks, asphalt, petroleum coke, and lubricating oils.[48] However, the categories shown, which are the major can-

[44]"1 981 Annual Report to Congress, " DOE/EIA-01 73(81), May 1982.

[45]Data from Regional Councils submitted to Energy Information Administration under form EP-411, April 1983.

[46]*Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil /reports* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-E-185, September 1982).

[47]The major difference between EIA projections and the values shown in table 9 are in the electric utility sector. EIA assumed an average growth in demand of 3 percent between 1981 and 1985. However, since demand actually dropped between 1981 and 1982, demand would have to grow by 4.7 percent annually between 1982 and 1985 to arrive at EIA's 1985 projections. OTA, on the other hand, has assumed a 1.5 percent annual demand growth between 1982 and 1985. We have also assumed that the conversions and new powerplants plannned to be completed by 1985, as reported to EIA under form EP-41 1, will be completed by that date.

[48]Because of weight and space limitations, aviation fuel substitutes would be limited to high-grade synthetic fuels. Because of space limitations and, in some cases, boiler derating, substitutes for marine fuels would require synthetic fuels or extensive end-use modifications. Substitutions for petrochemical feedstocks and lubricating oils would have to be some forms of synthetic fuel. Although asphalt could be replaced by concrete and other materials, it would require extensive changes in paving and surface repair procedures. Moreover, petroleum coke is a normal byproduct of petroleum refining. Most of it is used for heat at the refinery, while the remainder is used for metallurgical purposes. Although the metallurgical coke could be replaced with high-grade coal, converting the coke to liquid fuels would be no easier than converting the coal to a synthetic fuel. Consequently, although substitutes exist for all of these uses of oil, the leadtimes for replacing large quantities of oil are likely to be considerably longer than 5 years, and, in some cases, the substitution makes little practical sense.

Table 9.—Estimated 1985 Oil Consumption by Region and End Use (thousand B/D)

		Region									
Sector	Total	1	2	3	4	5	6	7	8	9	10
Electric utilities:											
Distillate oil	50	a	a	15	10	10	10	a	a		a
Residual oil	590	175	170	50	80	15	a	a	a	9	a
Residential and commercial heat and hot water:											
Distillate oil	775	160	170	145	60	140	45	15	10	a	25
Kerosene	110	a	a	a	25	25	15	15	a	a	a
LPG	170	a	a	10	35	35	25	30	10	10	a
Residual oil	210	15	65	15	10	5	55	a	a	35	a
Industrial boilers:											
Distillate oil	250	35	80	25	25	25	35	10	a	10	a
Residual oil	710	90	150	65	160	75	120	a	20	15	10
Surface transportation and mobile industrial engines:											
Gasoline	5,700	270	445	555	1,065	1,130	755	335	215	720	215
Diesel	1,830	40	100	155	315	320	375	145	105	190	90
Subtotal	10,400	790	1,190	1,030	1,790	1,785	1,430	560	370	1,090	355
Other	5,600	—	—	—	—	—	—	—	—	—	—

[a]Less than 10,000 B/D.

SOURCE: Office of Technology Assessment, didates for fuel switching, do include about 70 percent of the oil use projected for 1985.

In the following, each of the major end-use sectors is considered separately to derive estimates of the rate that oil replacement technologies could be deployed and the amount of oil that can be replaced. Electric utilities are considered first in order to provide estimates of the amount of electricity not generated by oil that could be available for fuel switching in other sectors. Heat and hot water in the residential and commercial sectors are considered next, followed by industrial boiler fuels and mobile engines for transportation and other uses.

Electric Utilities

In 1981, electric utilities consumed about 1.1 MMB/D of oil. Ninety-four percent of this, or slightly more than 1 MMB/D, was residual oil used in base and intermediate load utility boilers. The remainder, or about 60,000 B/D was distillate oil used in combustion turbines and diesel engines for peak electric generation. With a modest increase in demand for electricity (1.5 percent per year on average), utility residual consumption could drop to 0.6 MMB/D by 1985 as new nonoil-fired plants are brought on line, while the distillate use is likely to remain relatively constant.

Beyond 1985, as in the past, oil consumption by electric utilities will depend critically on the demand for electricity. Because oil is the marginal fuel for electricity generation in many regions, small percentage changes in the demand for electricity can result in much larger percentage changes in oil consumption. (For example, a 1.5 percentage point change in the annual demand growth for electricity between 1980 and 1985 would change the projected 1985 utility oil consumption by about **0.5 MMB/D.) It is notoriously difficult,** however, to predict future demand; and the difficulties are compounded during times of rapidly changing energy prices such as those that would exist following a large oil shortfall. Consequently, for the purposes of this analysis, OTA performed the calculations using two different levels of change in demand for electricity, At the lower end, it was assumed that the depressed economic climate following the oil supply shortfall would result in relatively constant demand for electricity between 1985 **and 1990. At the up**per end, the estimates given by the North American Electric Reliability Council (N ERC)[49] were used. NERC projected that demand for electricity will grow by about 2 percent per year, on average.

The major actions electric utilities can take to reduce their oil consumption are to switch to natural gas and coal and to complete construction of nonoil-fired powerplants that are currently under construction and scheduled for completion between 1985 **and 1990.**[50] The actual mix of actions taken will vary among the utilities and regions, but the broad outlines of a potential response can be discerned.

Utilities can begin almost immediately to use more natural gas in the boilers that are equipped to burn both oil and natural gas. OTA estimated the amount of this dual-fuel capacity from the 1981 utility fuel use profiles[51] by assuming that the powerplants that burned significant quantities of both oil and gas in 1981 but were not scheduled for retirement or conversion to other fuels by 1985 would be capable of burning both oil and gas in 1985. These estimates indicate that, of the regions consuming large quantities of oil for electric generation (table 9), regions **2,4, and 9 have by far the most dual-fuel capacity. Regions 1 and 3 have only small amounts of dual-fuel capacity, and much of it is scheduled** for retirement or conversion by 1985.

Based on 1981 oil consumption,[52] the dual-fuel boilers could replace about 60,000 B/D of oil in region *2, 75,000* B/D in region 4, and 65,000 B/D in region 9 within a short time, say 6 months, following an oil cutoff. This would require a total of about 0.4 TCF/yr of natural gas or the energy equivalent of 0.2 MMB/D. Although this is twice the 0.2 TCF/yr of surplus natural gas allocated to

49" Electric Power Supply and Demand 1983-1992, " North American Electric Reliability Council, Princeton, NJ, 1983.

50Another possibility **is to construct new power lines frOm utilities with excess nonoil capacity to regions dependent on oil. The constraints here, however, are primarily institutional; and the uncertainties are large. Consequently, this option has not been included in OTA estimates.**

51 **Data from Energy Information Administration form 759.**

S* Ibid.

electric utilities (see section on "Natural Gas" under "Fuel and Grain Supplies"), later replacement of some of this gas through conversions to coal and so forth could bring the incremental utility consumption of gas down to its allocated level before the gas would be required by the commercia l/residential and industrial sectors. Consequently, it would be possible for the electric utilities to use 0.4 TCF/yr of gas initially, without violating OTA's allocation of the assumed 2 TCF/ yr of surplus natural gas.

Following this initial response, regional natural gas use will change as new gas pipelines are built, coal technologies are deployed, and new powerplants and interties are completed. It is probable, however, that gas prices will rise as a result of the increased demand for gas by utilities and other sectors; and much of the increased use of gas by utilities will eventually be replaced by other technologies.

A second type of fuel switching available to utilities is to convert oil-burning boilers to coal and coal water mixtures (CWMS) (see section on "Technologies"). Some utility boilers currently burning oil use coal as an alternative fuel and can switch quickly when oil prices rise, but the total amount of oil consumed in these boilers is not great.[53] Most oil-burning boilers will have to be modified to use solid fuels, either directly or as CWMs.

As explained in the section on "Technologies," the boilers that are suitable for conversion to solid fuels are those that were originally designed for coal but were subsequently converted to oil, and those that were originally designed for oil but are technically similar to coal-designed boilers. Of the boilers that are technically suitable for conversion, OTA assumed that only those that were brought into service on or after 1960 will actually be converted. This assumption reflects the fact that major investments are not likely to be made in the older generating plants because the remaining life of the facilities is too short to justify the expenditures. Based on these assumptions and the survey of utility boilers,[54] OTA identified 114 utility boilers in regions 1 through 4 and 9 that are suitable for conversion from oil to solid fuels.

Provided that the permits needed for the boiler conversion can be obtained in 10 months, a typical schedule for converting a utility boiler to solid fuel (including CWMs) might look something like that shown in figure 29.[55] A corresponding schedule for construction of a CWM preparation plant is shown in figure 30. CWM plant construction requires less time than boiler conversion; and because of this, the fraction of utility boilers that will convert to CWM as opposed to direct firing of the solid fuel does not have to be specified. Both conversions will require comparable leadtimes. As mentioned before, however, plants with limited space for coal-handling facilities would be more likely to convert to CWM.

Historically, the boiler industry has sold as many as 350 electric generating units to foreign and domestic utilities over a 5-year period;[56] and manufacturers of particulate control systems (to control particulate emissions) believe they can easily supply the necessary systems for 114 boiler conversions. Based on the historical rate, it is reasonable to assume that the conversion process could begin on half of the boilers during the first year after the onset of an oil shortfall, and the remaining half could be initiated the following year. The first boilers to be converted would then come on line a little over 2 years after the shortfall, and the conversions could all be completed within about 4 years.[57]

The generating capacity of facilities that can be converted from oil to coal (assuming that the converted boilers have 65 percent of the capacity

[53] According to EIA data (I bid.), electric utilities in region 3 consume the largest amount of oil in boilers that burn significant quantities of both oil and coal. The boilers in this region that were coal capable in 1981 and are not scheduled to be retired or replaced by 1985 consumed slightly less than 12,000 B/D of oil on average.

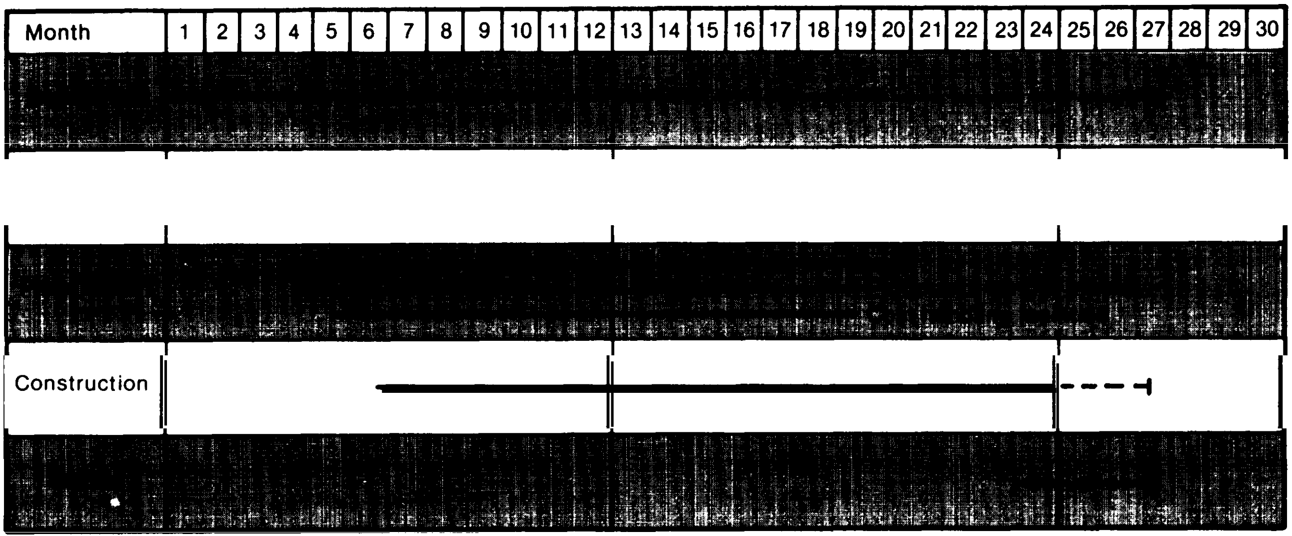
[54] " Survey of Oil-Fired Utility Boilers, " op. cit.

[55] Test burns can often be carried out with considerably shorter leadtimes than those shown in figure 21, For full commercial conversion, however, more permanent and time-consuming modifications are needed.

[56] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase 11," op. cit.

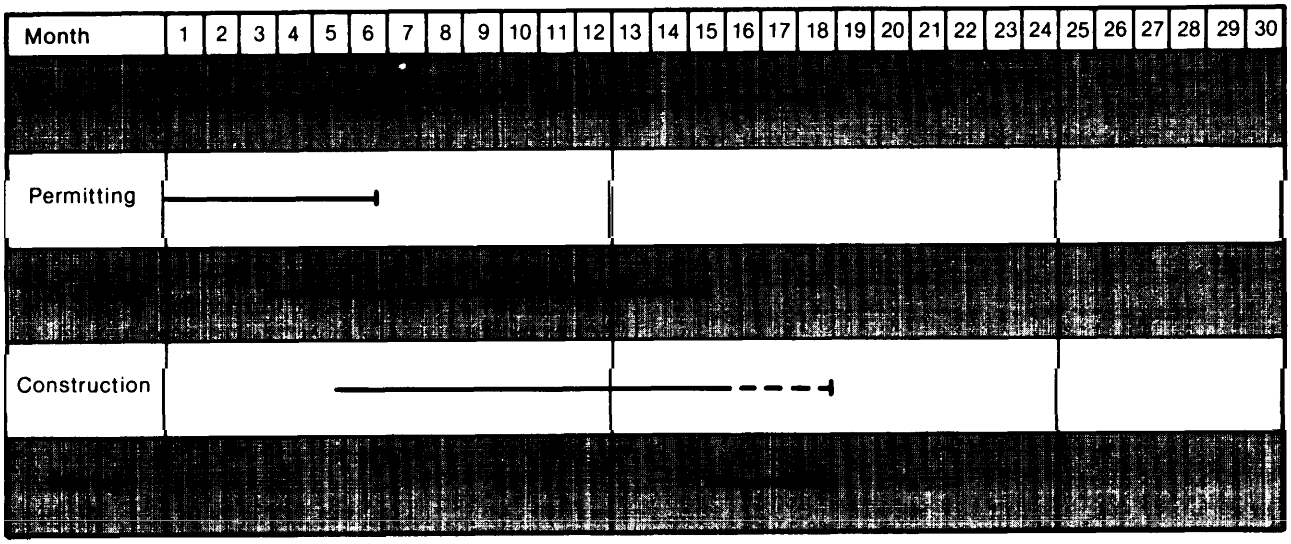
[57] To complete the conversions, the boiler wou Id have to be out of operation for 3 to 6 months while the modifications in the boiler and (probably) needed repairs discovered when the boiler is opened are carried out. Generally, however, there is sufficient reserve capacity in utility systems to make up for the lost power as long as this phase of the conversion is carried out during the utility's off-peak season.

Figure 29.-Schedule for Engineering and Construction: Utility Boiler Conversion to CWM-Firing



SOURCE: Office of Technology Assessment.

Figure 30.-Schedule for Engineering and Construction: Central CWM preparation Plant for Industrial Boilers



SOURCE: Off Ice of Technology Assessment.

they had when burning oil) is shown in table 10, together with the capacity of new generating facilities scheduled for completion between 1985 and 1990. The new and converted capacity was then added to the 1985 nonoil-fired generating capacity to determine the total nonoil capacity in each region. This capacity was compared to peak winter and summer demands for the two levels of 1990 demand described above (fig. 31). The total amount of electric energy that could be generated by the nonoil-fired facilities (assuming 60 percent capacity factors for the new and converted capacity) was also compared to the **1990 demands** for electricity.

Table 10.—Electric Generating Capacity of Facilities Converted From Oil to Coal and New Generating Capacity Scheduled for Completion Between 1985 and 1990

Region	Converted capacity[a] (MW)	New, nonoil capacity (MW)
1	4,427	3,484
2	6,321	3,730
3	5,331	3,730
4	5,199	20,098
5	—	12,286
6	—	15,088
7	—	1,702
8	—	1,718
9	6,080	10,949
10 : : : : : : : : : : : : : : : : :	—	2,979

[a]Assumes oil boilers converted to coal will be derated to 65 percent of the capacity they had with oil.

SOURCE: Office of Technology Assessment

This analysis indicates that new capacity and coal conversions could replace most of the oil used by electric utilities by 1990, **but small amounts would still be needed in regions 1 and 2, and Hawaii** would still be primarily dependent on oil for electric generation. For the higher level of demand for electricity, a small amount of oil would also be needed in Florida and California (see fig. **31).**[58]

In all, conversions to coal and new capacity additions could reduce utility oil consumption to about **0.05** to 0.1 MMB/D, depending on the demand for electricity. Natural gas could replace much of this remaining oil, except in Hawaii and possibly region 1, And the reductions in utility oil consumption might proceed something like that shown in table 11.

In order to estimate the amount of residential and commercial heating oil that could be replaced with electricity from excess nonoil-fired generating capacity, OTA assumed that this heating load would be centered around the utility's winter peak and that it would have an annual capacity factor of 35 percent. In other words, the total electric energy needed is the peak power demand times 3,060 hours, or 35 percent of the number of hours in a year. Peak winter demand (without the incremental home heating and hot water load) was subtracted from the total nonoil-fired capacity; and the excess capacity was converted to an equivalent amount of heating oil that could be replaced.

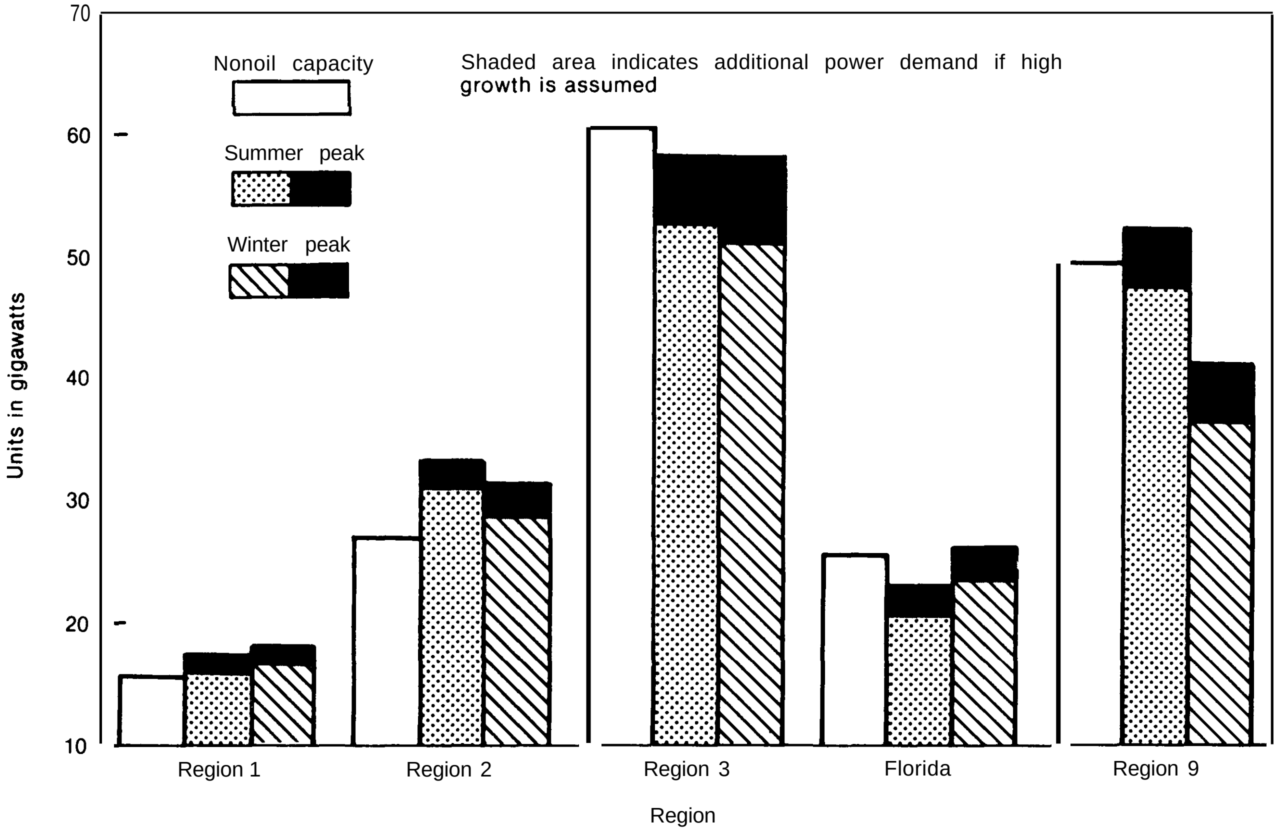
Based on this analysis, regions 1 and 2 and Hawaii would not have any excess nonoil-fired capacity for residential and commercial heating. In all other areas, however, the excess nonoil-fired capacity would be adequate by 1990 to replace all of the residential and commercial heating oil not replaced by natural gas (see below). But region 3 and Florida would be marginal cases; and, if other demand for electricity increases at the rate projected by NERC[59] (about 2 percent per year), utilities in these regions might be faced with peak demands which slightly exceed the nonoil-fired capacity available through conversion to coal and completion of new powerplants currently under construction. Therefore, these utilities may also have to convert some (otherwise unneeded) oil capacity to natural gas or delay retirement of some dual fuel capacity in order to supply the increased demand (including home heating) without using oil. Furthermore, although California utilities might still be using small amounts of oil during their summer peak, nonoil capacity would be adequate to accommodate the increased load during the winter peak without increasing their oil consumption.

In short, through conversions to coal and completion of new powerplants, together with a small increase in natural gas use, utilities could eliminate virtually all of their oil use by 1 **1990,** except in Hawaii and possibly region 1. Furthermore, these conversions could provide sufficient excess nonoil-fired capacity to replace all of the residen-

[58]The methodology used was to assume **that the peak demand curve is triangular. The amount of oil-fired capacity needed was then estimated by subtracting the nonoil-fired capacity from the peak demand. The amount of oil consumed would then be the area of the triangle, whose height is the amount of oil-fired capacity needed. Consequently, the ratio of 1990 oil consumption to 1985 oil consumption was estimated as the square of the ratio of the amount of oil-fired capacity needed at peak demand in 199o to that needed in 1985, This methodology overestimates the 1990 oil consumption in those regions where there is significant oil-fired baseload capacity used in 1985, but the resultant estimates of 1990 oil consumption are sufficiently small that this problem is not significant. The methodology does not, however, result in an estimate that oil is needed in a region where it in fact would not be. The amount of oil that could be replaced was also double-checked by assuming that the new and converted capacity would operate at an average** 60 percent capacity factor, and in all cases the new and converted capacity was more than adequate to replace **the oil.**

[59]North **American Electric Reliability** Council, op. **cit.**

Figure 31.– Potential Nonoil-Fired Electric Generating Capacity and 1990 Peak Electric Demand for Selected Regions



SOURCE: Office of Technology Assessment.

Table 11.—Potential Utility Oil Consumption With Conversion to Natural Gas and Coal (thousand B/D)

Region/year	1985	1986a	1987	1988	1989	1990
1	175	175	139	62	41	41
2	169	109	67	b	b	b
3	63	63	45	19	b	b
4	89	14	b	b	b	b
5	28	28	18	10	b	b
6	15	15	b	b	b	b
7	b	b	b	b	b	b
8	b	b	b	b	b	b
9	98	33	28	20	16	16
10	b	b	b	b	b	b

[a]The sharp drop is due to switching to natural gas in dual fueled boilers.
[b]Less than 10,000 B/D.
[c]Assumes half of the oil used for electric peaking is replaced by natural gas within 2 years.

SOURCE: Office of Technology Assessment.

tial and commercial oil not replaced by natural gas, except in regions 1 and **2 and Hawaii.**

The above results are particularly sensitive to actual developments in regions 1 and 2, however. Delays in conversions or completion of powerplants currently under construction could increase oil consumption in these regions significantly. On the other hand, construction of new power lines and increased purchases of electricity from Canada and region 5 would reduce these regions' oil dependence and possibly provide some excess capacity for residential and commercial space heating and hot water.

Residential and Commercial Space Heat and Hot Water

Almost 1.3 MMB/D of oil was consumed in 1981 for space heating and hot water in the residential and commercial sectors. Over 60 percent of this, or 0.8 MMB/D, was distillate fuel oil. The remainder was divided among LPG (0.2 MMB/D), residual fuel oil in commercial buildings (0.2 MMB/D), and kerosene (0.1 MMB/D).[60] Although demand for oil in these sectors dropped slightly in 1982 and 1983, it is unclear how much was due to short-term behavioral changes and how much was due to fuel switching and increased efficiency. Consequently, for the purposes of this analysis, OTA made the conservative assumption that residential and commercial demand for these fuels will be about the same in 1985 as it was in 1981.

The major fuel switching options open to the residential and commercial sectors are conversions to natural gas, electricity (where surplus nonoil-fired capacity exits), and solid fuels. Natural gas conversions are considered first, followed by conversions to electricity. Conversions to solid fuels are then examined for the regions where the combination of gas and electricity cannot replace all of the oil use within 5 years.

Conversion to Natural Gas

In 1980, about 14 million households in the United States used fuel oil or kerosene for heat.[61] About 36 percent of these are in rural areas,[62] which are generally too far from existing natural gas lines and where the population densities are too small to justify the cost of constructing distribution lines to these houses. Similarly, most of the households using LPG are located in rural areas and are not candidates for conversion to natural gas.

Many of the urban households that use oil for heating, however, are already connected to gas lines and use gas for hot water and/or cooking; and most of the others are located near existing gas lines. If 80 percent of the urban households could be converted to gas, about half of all residential users of fuel oil and kerosene could convert. If we assume a similar market penetration for commercial users of these fuels, conversions from oil to gas could replace about 0.44 MMB/D of oil (see table 9).

These conversions to natural gas would require the installation of about 7 million burners in residential households and about 1 million burners in commercial establishments, together with about 1 million new boilers where the old oil-fired ones required replacement.[63] In addition, about 5 million customers would require the installation of new distribution lines, while 2 million to 3 million are already connected to gas lines.[64]

Current production capacity for natural gas burners is about 1.5 million units per year;[65] and the highest historical rate for connecting new gas customers is about 1 million per year. Consequently, with only a modest growth in these rates, all of the potential gas customers could be supplied with new distribution lines (where needed) and gas burners within about 4 to 5 years. With this rate of deployment, new gas boilers would not be a constraint, since current production capacity is about 0.4 million units per year[66] and the needed supply could be provided within 2.5 years.

In addition to these generic constraints, gas use for heating in New England (region 1) is currently

6110EI,4 "Annual Report to Congress, " Op. cit.

61 "Residential Energy Conservation Survey: Housing Characteristics 1980, " DOE/EIA-0134, June 1982; and "Residential Energy Consumption Survey, " DOE/EIA-0262 /l, April 1981.

62 lbid.

63 Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I," Op. cit.

64 Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase II, op. cit.

65 lbid.

66 lbid.

limited by the pipeline capacity. During the winter peak, the two main pipelines to the region generally operate at full capacity; and new trunk pipelines will have to be built to accommodate the increase in gas used for space heating. Although the additional capacity can be built in about 1 year along existing pipeline rights of way, assuming no permitting delays[67] this construction probably will have to precede any significant replacement of oil by gas in the residential and commercial sectors in region 1. Trunk pipeline capacity does not seem to be a constraint in other regions, however.

Because of the difference in the potential deployment rate in New England and that in other regions, it is necessary to derive a regional distribution for this new natural gas use in order to determine the national deployment rates. Owing to regional differences in electricity generating facilities, this regional break down is also necessary to assess the oil replacement potential from electricity considered below. In order to derive this distribution, OTA assumed that the increase in gas use in each region would be proportional to 1980 gas consumption in the residential/commercial sectors in that region, or 100 percent of the urban use of fuel oil and kerosene in that region, whichever is less. This methodology is based on the premise that regions with a larger current gas use have a more developed infrastructure (manpower, distribution system, and equipment) and, therefore, will be able to connect a larger number of new customers in a given time.

With these assumptions, the increase in gas use for space heating and hot water in each region is shown in table 12. And, based on a 1-year delay before conversions begin in New England, 4 years to make the end-use conversions (once they begin), and the regional market penetration in table 12, natural gas replacement of heating oil and kerosene could proceed something like that shown in table 13.

Table 12.—Potential Increase in Natural Gas Use for Space Heating and Hot Water

Region	Potential increase in natural gas use (thousand B/D oil equiv.)	Increase relative to 1980 demand (%)
	26	24
1	80	24
3	83	24
4	53	18
5	105	9
6	37	10
7	22	7
8	10	7
9	9	2
10 : : : : : : : : : : : : : :	15	24
Total	440	12

SOURCE: Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase n-Evaluation of Selected Technologies," contractor report to OTA, August 1983.

Table 13.—Potential Reduction in Oil Use in the Residential and Commercial Sectors Through Conversion to Natural Gas, Electricity, and Solid Fuels (thousand B/D)

	Year				
Fuel	1986	1987	1988	1989	1990
Natural gas.	40	180	380	440	440
Electricity ... , . . .	110	220	335	445	455
Wood and coal. . .	15	35	50	65	80
Total	165	435	765	950	975
Remaining oil consumption . .	1,095	825	495	310	285

SOURCE: Office of Technology Assessment.

Conversion to Electricity

Most of the remaining residential and commercial oil customers in regions 3 through 10 (except Hawaii) would be candidates for conversion to electricity for space heat and hot water. (Regions 1 and 2 are excluded from these conversions because there would not be excess nonoil-fired capacity to supply the electricity.) In some rural areas, new power lines would have to be constructed to accommodate the increased load; for some of the remaining oil customers, the cost of new power lines would be prohibitive. Assuming that 40 percent of the rural oil customers (taken to be 36 percent of the distillate and kerosene customers plus all of the LPG customers) would need new power lines and that half of these lines would not be built, customers consuming about 40,000 B/D of oil in regions 3 through 10 would not convert to electricity; but customers consuming a little over **0.4** MMB/D would be candidates for conversion to electricity.

Excluding the oil customers in regions 1 and **2, those OTA assumed** would convert to natural gas, and those located too far from adequate

[67] Ibid.

power lines, a little over 8 million customers could convert to electricity. Of these customers, about 35 percent or 3 million also used oil for hot water.[68] Consequently, the switch to electricity would require space heating for **8 million households and commercial establishments and about 3 million electric hot water heaters.**

In 1980, about 13.4 million portable electric heaters and 2.8 million fixed electric baseboard heaters were shipped.[69] If manufacturing facilities for these devices were operating at 70 percent of capacity in 1980, **current manufacturing capacity could supply 19 million space heaters and 4 million baseboard heaters per year.**

Furthermore, it has been estimated that, in 1981, about 0.5 million central heat pumps (for heating) and 1.5 million central air-conditioning systems were installed .70 Because of the similarity between heat pumps and air-conditioners, manufacturers of central air-conditioners could easily convert to making heat pumps. If manufacturing facilities were operating at 70 percent of capacity and one-third of the air-conditioner manufacturers can convert to heat pump manufacturing, about 1.5 million central heat pumps could be manufactured and installed per year. By an analogous reasoning process, 1981 installations of unitary (window-mounted) heat pumps and air-conditioners (estimated at 0.5 million and 3.7 million, respectively [71]) imply a production capacity of 2.5 million unitary heat pumps per year.

Between 1970 and 1980, the number of households with hot water heaters increased by 17 million; and the number with electric hot water heaters increased by 10 million .72 I n addition, an unknown number of hot water heaters were installed as replacements for existing heaters; and many of the manufacturers of nonelectric units could easily convert to produce electric units. Consequently, the production capacity for electric hot water heaters is probably at least 2 million units per year, and perhaps considerably larger.[73]

If **50 percent of the customers converting to electricity go to central heat pumps, 25 percent go to unitary heat pumps (4 to 5 units** per customer), and the remaining needs are supplied by electric resistance heating, the necessary equipment for the **8 million space heating conversions could be supplied in less than 4 years; and the 3 million hot water heaters could easily be supplied in this time or less. If the equipment were installed within 4 years in each region, the oil replacement by electricity could proceed like that shown in table 13. If, however,** more electric resistance heating were used, the initial oil replacement could be somewhat greater than that shown in the table. For example, if **75** percent of the customers go to electric resistance heating, over 70 percent of the total oil replacement shown for 1990 could be achieved by 1987.

Conversion to Solid Fuels

A third option open to residential and commercial oil users is to switch to solid fuels, primarily wood and coal. This option is most important in regions 1 and 2 because of the large supplies of wood and the lack of other options for residential and commercial customers. For these reasons switching to solid fuels is considered in detail for these regions. Elsewhere, however, most of the oil could be replaced by switching to natural gas and electricity. Consequently, while a detailed consideration of solid fuel switching would increase the initial rate that oil is replaced in regions 3 through 10,[74] it would not significantly

[68] This assumes that the proport ion **of** commercial oil customers **who use oil for both heat and hot water is the same as it is for residential oil customers.**

[69] ''Selected **Heating Equipment, " MA34N, U.S. Bureau of the Census.**

[70] **Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase I," op. cit.**

[71] **Ibid.**

[72] **" Housing Characteristics, " U.S. Bureau of the Census, 1970; and "Provisional Estimate of Social, Economic and Housing** Characteristics,''PHC **80-51-1, 1980.**

[73] Ignoring replacements **and assuming that half of the manufacturers of nonelectric hot water heaters converted to the production of electric heaters and that the manufacturing facilities operated at 70 percent of capacity during the 1970s, current production capacity would be 1.35 ÷ 0.7 = 1.9 million units per year.**

[74] Between 1978 **and 1980, the years when residential and commercial use of wood increased the fastest, wood energy use in these sectors increased by the equivalent of about 40 MB/D (thousand barrels per day) annually in regions 3 through 10** (EIA, ''Estimates **of Wood Energy Consumption 1949 to 1981 ," op. cit.). At the same time coal consumption in these sectors dropped by the equivalent of 15 MB/D annually. Ignoring the drop in coal consumption and assuming that this rate of wood use increase could be doubled and that wood heating is half as efficient as oil heating, then the total oil replacement shown in table 13 could be increased by about 35 MB/D in 1986, 70 MB/D in** 1987, and 105 MB/D in 1988 through inclusion of this rate of switching to wood in regions 3-10. The 1989 and 1990 totals, **however, would be unaffected.**

affect the total amount of oil replaced by 1990. Therefore, for the purposes of this analysis, OTA has simply assumed that half of the remaining residential and commercial oil use in regions 3 through 10, or about 20,000 B/D, could be replaced with solid fuels.

Historically, the largest increase in the use of wood in the residential and commercial sectors occurred between 1978 and 1980 and amounted to the energy equivalent of about 4,000 B/D annual increase in each of regions 1 and 2.[75] Assuming that this rate of increase in wood use could be doubled and that wood heating is half as efficient as oil heating, then wood could replace an additional 40,000 B/D of oil in regions 1 and **2.**

Although national coal use in the residential and commercial sectors has declined each year since at least 1950, coal consumption by these sectors in regions 1 and 2 experienced a 1-year increase around 1980 by the energy equivalent of 1,000 B/D of oil in region 1 and 3,000 B/D in region 2.[76] Assuming this annual increase could be doubled and that coal heating is equivalent to wood heating in efficiency, then coal could replace another **20,000** B/D of oil within **5 years.**

As shown in table 13, inclusion of solid fuel conversions would increase the amount of oil replaced by about **80,000** B/D in 1990. Although the total increase in the use of solid fuels could be larger, most of the additional use above **80,000 B/D** would probably be a substitute for or an addition to conversions to natural gas and electricity in regions **3 through 10.**

The above analyses indicate that, within 4 years after the onset of an oil supply shortfall, fuel switching could virtually eliminate the use of oil for space heating and hot water in most regions of the country. Replacing all of the oil used by the residential and commercial sectors in regions 1 and 2, however, would take considerably longer, owing to the heavy dependence on oil of these sectors and electric utilities in the regions.

[75]EIA, **"Estimates of Wood Energy Consumption 1949 to 1981 ," op. cit.**

[76]"State **Energy Data Report, " U.S. Department of Energy,** DOE/EIA-0214(**81),** June **1983.**

Industrial Boilers

In 1980, the industrial sector consumed about 0.7 MMB/D of residual fuel oil, mostly as a boiler fuel, and another 0.2 MMB/D of distillate fuel oil for a variety of heat purposes, including process heat and some boiler fuel.[77 78] By 1982, residual use dropped to 0.5 MMB/D and distillate use also dropped slightly,[79] For the purposes of this study, however, OTA assumed that, with some economic recovery, Industrial use of these fuels will return to their 1980 values by 1985.

The major replacements for oil used as a boiler fuel are solid fuels (direct combustion and gasification of coal and wood and CWMS) and natural gas.[80] Conversions to solid fuels are considered first, followed by estimates of the rate that the available natural gas could replace the remaining oil use in industrial boilers.

Conversion to Solid Fuels

In 1979, there were about 146,000 oil-fired industrial boilers in the United States, of which nearly 142,000 had a capacity of less than 50 MMBtu/hr.el Nevertheless, almost half of the oil used as boiler fuel was consumed in the 4,000 boilers over 50 MMBtu/hr, and by 1985 these boilers will consume an estimated 0.4 MMB/D.

Assuming that half of the oil consumed in the larger (greater than 50 MMBtu/hr) boilers could be replaced with solid fuels[82] 83 and that the average boiler being replaced or converted had a

[77]Total **industrial consumption of disti I late fuel** oi **I was about 0.7** MMB/D **in 1980. However,** OTA **assumed that 90 percent of the distillate used in the non manufacturing sectors was used for mobile engines such as in off-road construction, mining, and agricultural equipment and machinery. The fuel used by these mobile engines are included in the next section, together with oil consumption for transportation.**

[78]EIA, '' **1981** Annual Report to Congress, op. cit.

[79]"1 982 Annual Energy Review, " U.S. Department of Energy, DOE/EIA-0384 (82), April 1983.

[80]In addition, since some of the steam from boilers is used for mechanical drive, a portion of the boiler fuel **could be replaced with electric motors; but** OTA **has not analyzed this option.**

[81] **"Population and Characteristics of Industrial Boilers in the U.S., " U.S. Environmental Protection Agency, EPA/600/7-79-l 78-A, August 1979,**

[82]Gibbs & **Hill, Inc.,** ''Oil **Replacement Analysis, Phase 11, " op. cit.**

[83]See **also P. C.** Kurtzrock, **"Planning Objectives, " proceedings of the Coal-Water Fuel Technology Workshop,** BNL-51 **427, Mar. 18-21, 1981.**

capacity of 135 MMBtu/hr and operated at a 35 percent capacity factor, then about 1,000 large boilers would have to be replaced or converted.[84] Historically, the highest annual sales of 100 to 250 MMBtu/hr boilers was 248 units in 1973.[85] In this size range, however, most **solid fuel** boilers are field-erected, for which the historical high was **57** units sold in 1969; but the major boiler manufacturers estimate that, at full capacity and with considerable duplication of engineering designs, up to 550 boilers could be field-erected within 3 to 4 years.[86] In addition, many of the boilers could be converted to burn solid fuels or CWMS directly or could be equipped with gasifiers; and the manufacturing constraints are considerably less severe for these types of conversions. In these cases, additional "slide along" boilers would be needed to make up for the lost capacity resulting from boiler derating. However, these would be smaller, prefabricated boilers, for which production capacity is about 1,100 units per year.[87]

Regardless of whether the boilers are replaced or converted, each system would require a particulate control system (PCS) to limit particulate emissions. Historically, the largest number of PCSs sold was 200 units in 1980; but the industrial Gas Cleaning Institute estimates that 1,000 units could be produced in about 3 years.

Based on these production capacities, it appears that 1,000 large industrial boilers could be converted to solid fuels in about 3 to 4 years. Assuming 4 years and the engineering and construction schedules shown in figures 32 and 33, replacement of oil by solid fuels in large industrial boilers could proceed something like that shown in table 14.

As indicated above, solid fuel boilers to replace the smaller industrial oil-fired boilers could be manufactured at a rate of about 1,100 units per year, and perhaps 5,000 boilers could switch in 5 years.[88] Assuming that one-quarter of the small (less than 50 MMBtu/hr) boilers consume half of

[84] These assumptions reflect the fact that, of the boilers for which conversion is technically feasible, the boilers consuming the largest amounts of oil are most likely to be converted.

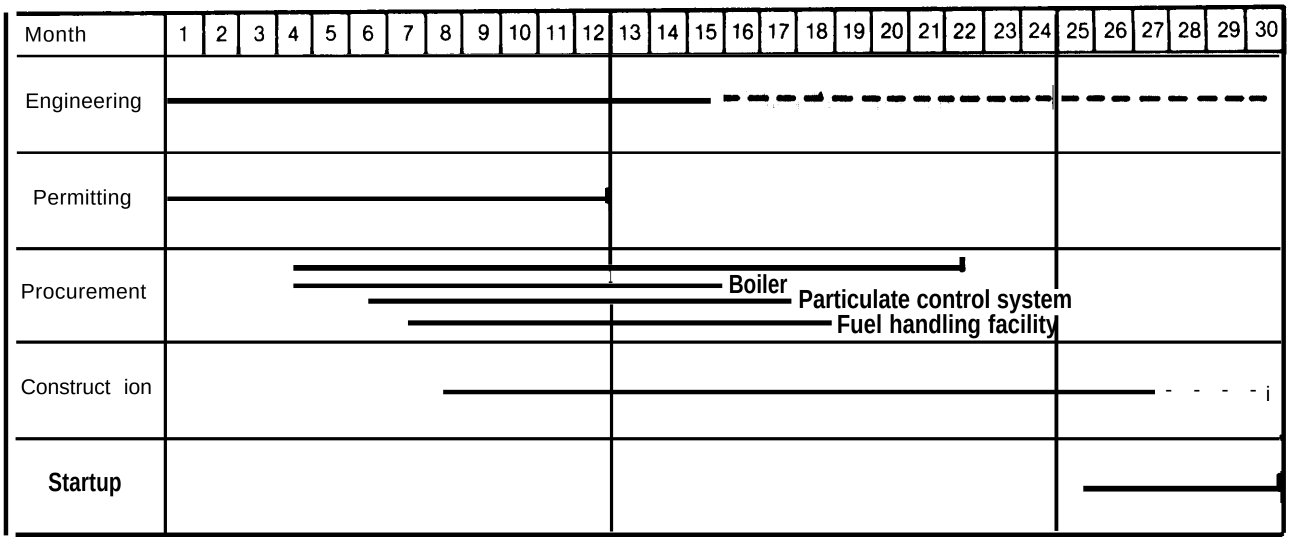
[85] Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase 11, " op. cit.

[86] Ibid.

[87] The recent historical high for the sales of 10 to 100 MM Btu/hr solid fuel boilers was 100 units in 1973. However, manufacturers of gas and oil boilers could easily convert their facilities to produce solid fuel boilers; and when these are included, the historical 1 year high is 800 boilers. Assuming that this is 70 percent of peak capacity, then the latter is 1,100 units per year.

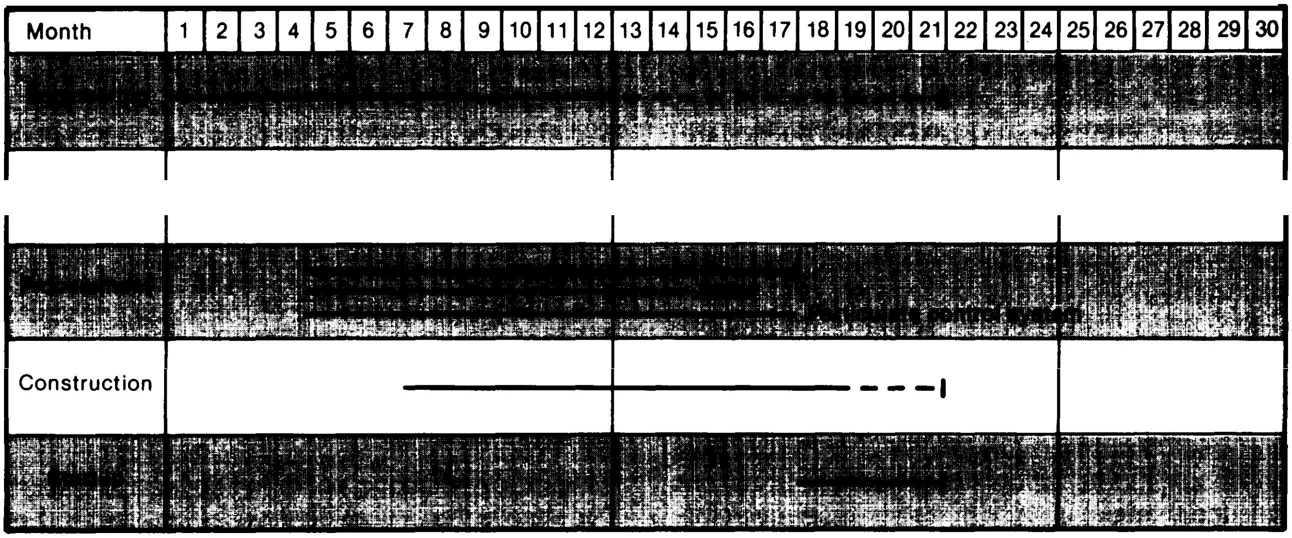
[88] This assumes that 500 of these boilers would be needed in conjunction with the large boiler conversions, in order to compensate for derating.

Figure 32.—Schedule for Engineering and Construction: Coal" or Wood-Firing Steam Generating System, Fuel-Handling Facilities, and Particulate Control System



SOURCE Off Ice of Technology Assessment

Figure 33.-Schedule for Engineering and Construction: Industrial Boiler Conversion to Solid Fuels



SOURCE: Office of Technology Assessment.

Table 14.—Potential Reduction in Oil Used in Industrial Boilers Through Conversion to Solid Fuels and Natural Gas (thousand B/D oil)

Fuel	1985	1986	1987	1988	1989	1990
	Year					
Solid fuels	—	O	40	90	150	200
Natural gas	—	190	330	420	445	455
Total	—	190	370	510	605	655
Remaining oil consumption in industrial boilers	960	770	590	450	355	305

SOURCE: Office of Technology Assessment and Gibbs& Hill, Inc., "Oil Replacement Analysis, Phase n-Evaluation of Selected Technologies," contractor report to OTA, August 1983.

the oil **used** in small boilers, an additional 0.04 MMB/D of oil could be replaced by solid fuels.[89] The inconvenience of using solid fuels, however, could limit the number of small boiler conversions to considerably less than this number.

Conversion to Natural Gas

The other major option is to convert industrial boilers to natural gas. Based on OTA's allocation of the assumed quantities of natural gas, the industrial sector could increase its gas use by the equivalent of about 0.45 MMB/D of oil. If the new gas customers consume, on average, the same amount of gas per customer as current industrial gas users (i.e., **42** billion Btu/yr[90]), this increment of natural gas use would require approximately 22,000 new customers.[91]

In 1981, there were 187,900 industrial gas customers, down from 209,100 in 1973.[92] Many of these customers switched back to oil while retaining the ability to reconvert quickly to gas. In addition, the number of industrial gas customers grew by 5,000 to 7,000 customers per year in the late 1960s. This indicates that, even if some new distribution lines must be built, the 20,000 industrial customers could probably be converted to gas in 2 to 3 years. Assuming 2.5 years for the conversions, the rate of oil replacement by nat-

[89]One-quarter of **the boilers would be 35,500 boilers. Assuming** these boilers use 0.25 MMB/D of oil, then 5,000 boilers would use approximately 0.035 MMB/D.

[90]"Gas Facts," American Gas Association, Department of Statistics, Arlington, VA, 1981.

[91]An alternative way to derive the number of new customers is as follows. Assume that all of the 3,000 large boilers not converted to solid fuels **convert to gas. These boilers would consume about 44 percent of the gas increment, or the equivalent of 0.2 MMB/D of oil.** If one-quarter of the small gas boilers consume half of the remaining 0.5 **MM B/D of oil targeted for replacement, then the remaining 0.25 MM B/D equivalent of gas allocate to industry would involve 142,000 ÷ 4 = 35,500 boilers. Many industrial concerns with small, package boilers have several boilers in parallel and/or reserve boilers to improve system reliability. Assuming two boilers per customer, on average, the total number of new gas customers would be 35,500 ÷ 2 + 3,000 = 20,750.**

[92]**" Gas Facts," American Gas Association, op. cit.**

ural gas could look something like that shown in table 14. Furthermore, it is clear that more oil could be replaced if natural gas supplies are greater than those assumed, but the rate of oil replacement would taper off as more conversions would be needed for each additional increment of oil replaced.

This analysis indicates that almost 0.7 MM B/D of oil used in industrial boilers could be replaced with solid fuels and natural gas within 5 years after an oil supply disruption. About 65 percent of the total would be replaced by the increased natural gas supplies that OTA assumes will be available to industry. Clearly, the actual oil replacement will depend critically on the quantity of surplus gas that actually materializes.

Mobile Engines

In 1980, highway transportation consumed about 6.3 MM B/D (oil equivalent) of gasoline and 0.9 MM B/D of diesel fuel. The gasoline went primarily to automobiles (4.6 MMB/D) and trucks (1.7 MM B/D), while trucks consumed 92 percent of this diesel fuel.[93] Non highway transportation consumed an additional 2.0 MM B/D of oil, primarily as jet fuel (0.8 MMB/D), residual fuel oil in ships (0.7 MMB/D), and diesel fuel in trains **(0.3 MMB/D) .94 In addition, off-road** vehicles and equipment in construction, mining, and agriculture (the industrial sector) consumed an estimated 0.5 MMB/D.[95]

By 1985, increased fuel efficiency in automobiles and light trucks is likely to reduce gasoline consumption *to* around **6 MMB/D,[96] while the** other categories are likely to be similar to their 1980 values.

The principal technologies studied for replacing the oil used in mobile engines are ethanol production and conversions to compressed natural gas (CNG), liquefied petroleum gas (LPG), and mobile gasifiers. These substitutes are best suited to spark ignition (gasoline) engines, although they can be adapted to diesel engines. Ethanol can also be used as a fuel for jet engines, but its lower energy density (energy per unit weight) as compared to jet fuel and the need for extensive testing to ensure safety are likely to limit its use severely in jets in the near future. It is not necessary, however, to specify the exact end uses, since the potential for these alternatives is quite limited relative to the amount of fuel consumed by mobile engines.

Ethanol Production

A **50 million gal/yr ethanol distillery can be constructed** in about 2 years, as shown in figure **34. Each distillery would require a 250 to 300 MMBtu/hr boiler and particulate control system identical to those discussed in the previous section.** To the extent that this equipment is supplied to ethanol distilleries, the supply for industrial boiler conversions would be reduced; and both types of activities could be delayed somewhat. Each distillery, however, would also require **3 to 5 centrifuge decanters with capacities of 250 to 400 gallons per minute.[97] Production capacity for centrifuges is proprietary, but one leading supplier indicated that, in an emergency, perhaps 500 steel castings could be obtained over a 5-year period.[98] With an average of four centrifuges** per distillery and a l-year delay after the equipment procurement before the final distillery becomes operational, perhaps 100 ethanol distilleries could be completed in 5 years. At this rate of construction, the boilers, particulate control systems, and other equipment needed for the distilleries could probably be obtained without significant delays.

One hundred ethanol distilleries of this size would produce 5 billion gallons of ethanol annually, with an energy content of about 0.2 MMB/D. Because of the energy used in agricul-

[93] G. Kulp and M. C. Holcomb, "Transportation **Energy Data Book, Sixth Edition, " Oak Ridge National Laboratory, Oak Ridge, TN, ORNL-5883, 1982.**

[94] **Ibid.**

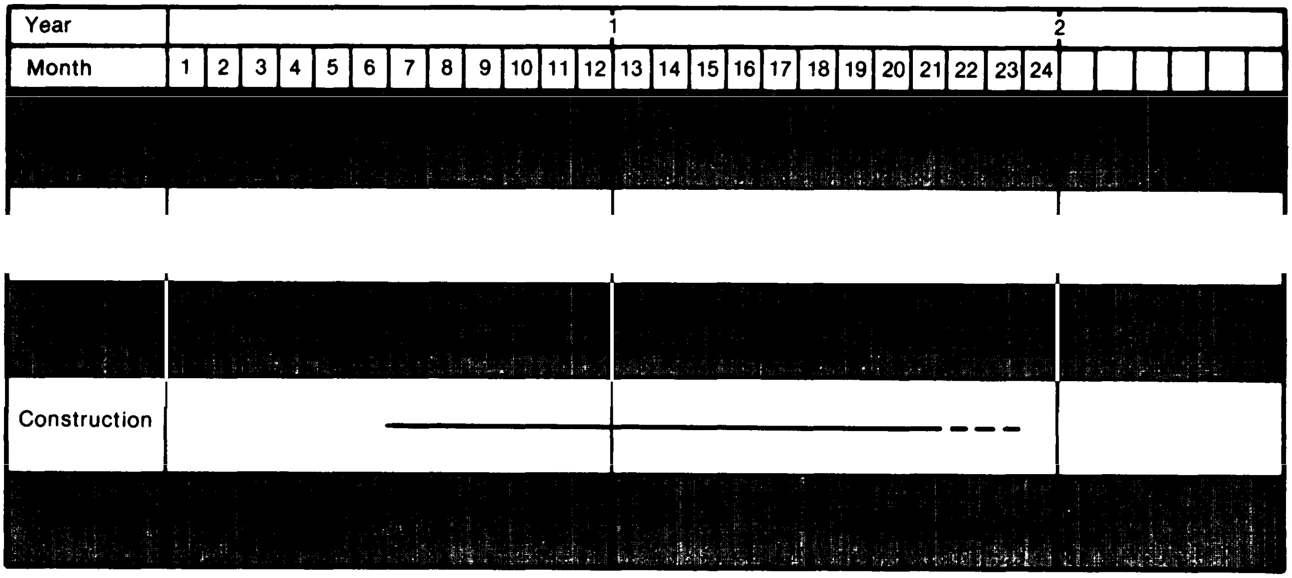
[95] Assuming that **90** percent **of the distillate and gasoline used** in **mining and construction was for mobile engines.**

[96] This **assumes that the average fuel efficiency Of new** cars sold **in 1985 will be 27.5 mpg and that the percentage efficiency increase in** light **trucks on the road will be half as large as for automobiles. Also, between 1979 and 1980, gasoline consumption dropped by 0.5** MMB/D; **and** OTA **estimates that 0.3** MMB/D **of this drop was due to people driving less. The 1985 estimate for gasoline consumption, however, assumes that driving levels would have returned to extrapolations of the pre-1 978 levels. See also** *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil /reports* **(Washington, D. C.: U.S. Congress, Office of Technology Assessment,** OTA-E-1 **85, September 1982.) (Note, however, that in the latter report, 1 barrel of oil equivalent is equal to 5.9** MMBtu, **while in the current report it is taken equal to 5.5 MM** Btu. **)**

[97] Gibbs & Hill, Inc., "Oil **Replacement Analysis, Phase I I,"** op. cit.

[98] Ibid.

Figure 34.-Schedule for Engineering and Construction of a 50 Million Gal/yr Ethanol Plant



SOURCE: Office of Technology Assessment.

ture to supply the grain feedstock for the distilleries, however, this ethanol would probably replace less than 0.1 MMB/D of oil, net (see app. B). Based on these estimates, oil replacement by ethanol could proceed as shown in table 15.

Conversion to Compressed Natural Gas

The analysis of vehicle conversions to CNG indicates that the factor limiting the rate of conversions is most likely to be the availability of natural gas compressors. A typical compressor with a capacity of 20 standard cubic feet per minute (scfm) could service about 20 vehicles, with slow fill (1 O hour) for 15 of the vehicles and fast fill (3 to 5 minutes) for the remaining 5. Larger fleets of vehicles would typically be serviced with multiples of this arrangement,[99] although they could use somewhat larger compressors. If the compressor operates at full capacity an average of 10 hours per day, 5 days a week, each compressor could deliver about 3 billion Btu of CNG per year.

[99] Ibid.

Table 15.—Potential Reduction in Fuel Use in Surface Transportation and Mobile Industrial Engines (thousand B/D oil)

	Year					
Fuel	1985	1986	1987	1988	1989	1990
Ethanol	—	0	25	50	75	100
CNG [a]	—	8	16	24	32	40
LPG [b]	—	40	40	40	40	40
Mobile gasifiers	—	o	0	50	100	100
Total [c]	—			164	247	280
		(48)	(121)	(244)	(367)	(440)
Remaining gasoline and diesel fuel consumption	7,530	7,480	7,410	7,290	7,160	7.090

[a] Compressed natural gas.
[b] Liquefied petroleum gas.
[c] Number in parenthesis indicates potential increase in LPG consumption in vehicles. However, at most 40,000 B/D would be from new production; the remainder would be a shift in LPG from' stationary uses.
SOURCE: Office of Technology Assessment.

In 1980, 5,512 gas compressors were shipped, which is close to the historical high of 5,770 units in 1974.[100] Assuming that manufacturing facilities were operating at 70 percent of capacity, then an additional 2,400 compressors per year could be manufactured.[101] If **2,000 of these could be manufactured to the specifications needed for CNG vehicle refills and the production increased by 50 percent per year,[102] then about 26,000 CNG compressors could be delivered in 5 years.** These compressors could provide enough CNG to replace about 0.04 MM B/D of oil with the deployment shown in table 15. If larger fleets use larger compressors, the total replacement could be increased somewhat; but in light of the optimistic assumptions about compressor availability, it seems clear that the total potential from CNG is small.

Conversion to Liquefied Petroleum Gas

As outlined in the section on "Fuel and Grain Supplies," an incremental production of 2 TCF/yr of natural gas would result in about 0.04 MMB/D oil equivalent of LPG suitable for internal combustion engines; and this would be sufficient to fuel about 1 million vehicles. The analysis of vehicle conversions indicates that about five times this many vehicles could be switched to LPG over a 5-year period.[103] Nevertheless, the full conversion capacity could be needed if the 0.16 MMB/D of LPG replaced from the residential and commercial sectors is to be used as a vehicle fuel. Only the new LPG production, however, would replace oil; the remainder would simply be a transfer of petroleum used in one sector to another. Consequently, the oil replacement potential would be limited by the rate that new LPG could be produced. Based on the previous analyses of new natural gas use, the oil replacement by LPG vehicles could develop as shown in table 1 s. To the extent that the natural gas is imported or made available through fuel switching and conservation, however, the LPG would have to be obtained from sources outside of the United States, which would be roughly equivalent to importing more oil.

Conversion to Mobile Gasifiers

The final technology considered is the mobile gasifier. The analysis of this technology indicates that the components needed for mobile gasifiers are so common that several million units could be produced annually, following an initial 2-year delay to establish standard designs and complete fleet tests.[104] Consequently, after the initial period it is likely that gasifier deployment would be limited by the potential market for these devices.

In Sweden during World War II, the market penetration of mobile gasifiers reached 30 percent of the automobiles (but later dropped to 10 percent), 55 percent of tile trucks, and 70 percent of the buses; [105] but this is probably much larger than could be achieved in the United States today. Assuming that gasifiers, on average, replace half of a vehicle's fuel needs and that market penetration reaches one-fifth of that in Sweden during World War II, then mobile gasifiers could replace about 0.1 MMB/D of oil. The oil replacement by mobile gasifiers could then proceed as shown in table 15. These estimates, however, are highly speculative.

This analysis of fuel switching in mobile engines indicates that perhaps 0.2 to 0.3 MMB/D of oil could be replaced, but the constraints are quite severe. Ethanol, which can be used with the least amount of end use difficulty, is derived from energy-intensive agricultural feedstocks. As agricultural production expands, the energy (per unit ethanol) consumed in supplying the feedstock increases; and the net oil savings drops. CNG use is constrained by the availability of gas compres-

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[100]"Pumps and Compressors," Current Industrial Reports, MA35P, U.S. Department of Commerce, Bureau of the Census, December 1981.

[101] In contrast to this, over 1.5 million air compressors were shipped in 1980 (Ibid.). However, natural gas compressors are far more complex than air compressors because of stricter sealing requirements, higher pressures, and the need for intercoolers, condensate traps, and precautions against sparking. The air compressor manufacturing capacity, therefore, cannot be used to judge production capacity for CNG compressors.

[102]This corresponds to an 1 l-percent annual increase in production capacity for all gas compressors with all of the increase going to natural gas compressors. This may be overly optimistic in view of the historical 3.1 -percent annual increase in industry sales over the past 20 years (I bid.) and the long leadtime for some items needed to manufacture gas compressors (Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase 11, " op. cit.).

[103]Gibbs & Hill, Inc., "Oil Replacement Analysis, Phase 11," op. cit.

[104]Rasor Associates, Op. cit.

'051 bid.

Photo credit: National Academy Press

Mobile gasifiers can be used to fuel a variety of vehicles, but market demand for the devices during a large oil shortfall is highly uncertain sors. Oil replacement by LPG is limited by the quantities of LPG that can be produced from new natural gas production. And mobile gasifiers probably will be limited by the inconvenience of using solid fuels.

Summary

The potential for reducing oil consumption through the fuel switching options considered here is summarized in table 16. If these options are implemented, the major remaining uses of oil would be for transportation and other mobile engines, petrochemical feedstocks, asphalt, lubricants, and specialized industrial processes. There would also be some oil use remaining for home heating in regions 1 and **2 and** some industrial boilers. Replacing large additional quantities of oil, therefore, will require production of synthetic transportation fuels and chemical feedstocks from coal and biomass.

A critical assumption in this analysis, however, is that sufficient natural gas would be available to replace 1 MMB/D of oil. If this is not available, then space heating and hot water needs in most regions could rely more heavily on electricity, but oil consumption by industrial boilers would increase substantially above these estimates.

Table 16.—Summary of Potential Reduction in Oil Use Through Fuel Switching (thousand B/D oil equivalent)

	Year				
Use	1986	1987	1988	1989	1990
Electric utilities	**320**	**430**	**500**	**570**	**590**
Residential/commercial space heat and hot water	**165**	**435**	**765**	**950**	**975**
Industrial boilers	**190**	**370**	**510**	**605**	**655**
Surface transportation	**50**	**80**	**165**	**245**	**280**
Total	**725**	**1,315**	**1,940**	**2,370**	**2,500**
Increased natural gas use[a]	**440**	**740**	**960**	**1,000**	**1,020**
Increased solid fuel use[b]	**120**	**390**	**780**	**1,120**	**1,240**

[a]Includes Increased use of gas for incremental fertilizer production for the agriculture used to supply ethanol feed stocks
[b]Includes fuel used in ethanol production and for InCreased electric generation, assuming that 80 perCent Of the increased electric generation is in coal-fired powerplants.

SOURCE: Office of Technology Assessment.

ENVIRONMENTAL IMPACTS

The major changes in fuel use due to fuel switching are a reduction in residual and distillate oil use and an increase in natural gas and coal consumption. Although there would be a small decrease in emissions as a result of the reduction in distillate fuel oil use and a corresponding increase in natural gas consumption, the major impacts are likely to be associated with the changes in residual fuel oil and solid fuel consumption.

The increased use of coal (up to 115 million tons/yr) will require that production be increased by up to 13 percent over 1982 production, with attendant problems such as acid mine drainage, subsidence, and other mining-related impacts. About 65 million tons/yr of coal would be used in utility and industrial boilers converted from oil. To avoid increases in sulfur and particulate emissions, these boilers would have to use low-sulfur coal and particulate control systems, for which supplies are adequate for the postulated scenarios. However, there probably would be an increase in NO_x emissions in some of these boilers; and to the extent that fuels with higher sulfur contents are used in converted boilers (without new scrubbers), SO_2 emissions would also increase.

An additional 35 million tons/yr of coal would be used in new and existing coal-fired utility boilers to replace (mostly distillate) fuel oil used in the residential and commercial sectors, which would also lead to an increase or at least a delay in the reduction (through retiring older boilers) of SO_2 and NO_x emissions.

The remaining 15 million tons/yr would be used in new ethanol distilleries. Distilleries with a capacity of greater than about 50 million gal/yr of ethanol supplied with a single boiler (greater than 250 MMBtu/hr) would be subject to Federal New Source Performance Standards; but there are currently no Federal regulations for smaller boilers. Furthermore, the Environmental Protection Agency regulations promised for 1986 for boilers rated at 50 MM Btu/hr and larger will not include regulations on SO_2 emissions; and it is unclear how stringent the other regulations will be. Consequently, it is likely that emissions from most of the ethanol distilleries will be determined primarily by State and local requirements for emissions controls, and many distilleries will locate where these requirements are least stringent. Furthermore, since the ethanol will be used to replace gasoline (rather than residual fuel oil, as in the case of boiler conversions above), even if low-sulfur coal is used, a net increase in SO_2 and NO_x emissions will occur.

Production of 5 billion gal/yr of ethanol (which is capable of reducing U.S. oil consumption by about 0.1 MMB/D) would require a 15-percent increase in grain production. This would probably lead to more than a 15-percent increase in soil erosion and the accompanying pesticide and fertilizer runoff, because much of the new cropland used for grain production is more erosive than average cropland.

The increased supplies of wood for fuel could be supplied as part of careful forest management programs without significant adverse environmental impacts. However, if the wood is harvested in a haphazard manner, damage to the forest and, eventually, forestland productivity could be substantial. Furthermore, burning wood without emissions controls (e.g., for home heating) would likely lead to significant local increases in particulate emissions, including higher levels of polynuclear aromatics (which are generally not a problem with either central electric power generation or natural gas or oil combustion); but sulfur emissions from wood are insignificant.

APPENDIX A–REASONS FOR EXCLUDING VARIOUS OIL REPLACEMENT TECHNOLOGIES FROM DETAILED CONSIDERATION

The initial list of fuel switching technologies (table 6) was screened to identify those options with the greatest potential for replacing at least 0.2 MM B/D of oil within a 5-year period following a large oil shortfall in 1985. Some of the technologies that were eliminated from further consideration by this screening process and the specific reasons for eliminating them are given below.

Fossil Synthetic Fuels

The primary concern of this study is to examine the technologies that can be deployed within 5 years after the onset of an oil shortfall. Construction of new, large-scale oil shale and coal liquids plants is likely to take longer than 5 years.[106] Although additional modules could be added to synfuel plants already in operation by 1985-90, in OTA's judgment the total additional output, beyond that already planned, is not likely to exceed 0.1 MMB/D before 1990. Consequently, large-scale oil shale and coal liquids plants are judged to be longer term options that are beyond the scope of this study.

True in situ oil shale retorts,[107] on the other hand, can be constructed in a matter of weeks. The retorts, which are underground cavities prepared with explo-

[106] *Increased Automobile Fuel Efficiency and Synthetic Fuels,* op. cit.
[107] Ibid.

sive charges, cover about an acre each and produce around 20,000 barrels of shale oil over a 6-to 8-month period. Achieving 20,000 B/D of production would require the completion of at least one retort per day, year round. This would entail a sharp increase in the number of trained personnel, construction of pipelines and new roads to remote areas, and considerable new equipment. (To date about 25 test retorts have been completed over a 7-year period.) The logistics of accomplishing this expansion, together with the remaining technical uncertainties in the process (notably the depth of overburden that can be accommodated and the control of fugitive emissions) would probably limit production to well below 0.1 MMB/D within a 5-year time period.

Another possibility is to use methanol produced from natural gas or to convert the methanol to gasoline. Currently, the United States has the capacity to produce methanol with an energy equivalent to about 50,000 B/D of oil (i.e., about 1.5 billion gal/yr of methanol). A fraction of this could be diverted to use in vehicles; and some new capacity could probably be built in 3 to 4 years, if the appropriate permits could be obtained quickly. However, the large capital investments needed, the dependence of these plants on uncertain future supplies of natural gas, the need to prove the methanol-to-gasoline step in commercial practice in this country, and (in the case of methanol) the uncertain demand for the product are all likely to limit rapid investment in these options. At best, one would expect potential investors in these technologies to wait until natural gas supplies and prices had stabilized somewhat, so that they could make reasonable estimates of the profitability of their investments. [108] This delay would probably mean that only very limited quantities of liquid fuels from natural gas would be produced within the 5-year timeframe, even if natural gas supplies eventually proved to be adequate. Furthermore, to the extent that surpluses of natural gas are available, more transportation fuel could be produced in the shortest time by using the natural gas to replace distillate fuels directly and converting them to diesel and gasoline.[109] Consequently, elimination of a detailed consideration of liquid fuels from natural gas is not likely to affect materially the results of this assessment or underestimate the oil replacement potential from fuel switching significantly.

Active Solar Systems

Currently there are about 500,000 active solar systems installed for heat and hot water, displacing the energy equivalent of 3,000 to 5,000 B/D of oil.[110] In 1982, about 150,000 systems were installed; [111] and at this rate of installation, active solar systems of this type could replace the energy equivalent of 5,000 to 8,000 B/D of oil by 1985. Even if this replacement could be increased by a factor of 10 between 1985 and 1990 (a highly optimistic estimate), it would still be less than the equivalent of 0.1 MMB/D of oil; and only part of the energy directly replaced would be oil. (Although the electricity and natural gas replaced by solar systems could be used to replace oil, the uncertainty in the future supplies of electricity and natural gas are far greater than any potential contribution from these sources.) Consequently, it is judged that the oil replacement potential of active solar systems between 1985 and 1990 is too small for a detailed consideration of this option.

Photovoltaics

Current photovoltaics production capacity is about 10 MW peak [112]/yr and could grow to 30 MW peak/yr by 1984. However, even if the production capacity

[108] It should be noted that potential investors in liquid synfuels from natural gas differ in three significant ways from those who may invest to convert facilities from oil to natural gas. First, the synfuel investor has the option not to invest without suffering a loss, while businesses may require fuel to stay in business. Second, the investment needed to convert from oil to natural gas is usually only a small part of a business' total investment, and the direct cost to the business (per unit oil replaced) of converting is usually considerably less than that of a synfuel project. Consequently, the risk is lower for the business converting than for a synfuel investor. Even if the investment proves to be unprofitable, it is not necessarily a mistake that would lead to bankruptcy for a company converting to natural gas, whereas it would be for a synfuel project. Third, a business could convert to natural gas while retaining the ability to convert quickly back to oil if natural gas supplies became too scarce. This option is not feasible for the synfuel producer.

[109] The quantity of transportation fuel that can be produced from a given amount of natural gas by displacing residual fuel oil, however, is closer to the amount that can be produced by converting the natural gas to liquid fuels, since the efficiency of converting gas to liquids is closer to that of upgrading residual fuel to diesel and gasoline, about 70 percent. Nevertheless, it would still take considerably longer to convert large quantities of natural gas to liquids than to replace and upgrade residual oil, since new natural gas liquefaction facilities would have to be built, whereas there would probably be excess residual upgrading capacity during a shortfall ("Emergency Preparedness for Interruption of Petroleum Imports into the United States, " National Petroleum Council, April 1981).

[110] "The 1983 Renewable Energy Forum: Directions '90," Renewable Energy Institute, Conference Proceedings, Wye Plantation, MD, June 16-18, 1983; and Gibbs& Hill, Inc., "Oil Replacement Analysis, Phase I," op. cit.

[111] "Renewable Energy Forum, " op. cit.

[112] Peak power corresponds to the maximum power output when the photovoltaic cell is illuminated with the intensity and spectrum of light produced by the Sun at noon on a clear day.

were to grow to 500 MW peak/yr by 1990 and all of the photovoltaic devices sold were used to replace oil, the total replacement would be less than 10,000 B/D, Consequently, the oil replacement potential of this option is too small for detailed consideration.

Electricity From Wind

Wind-powered electric generators are being tested by electric utilities in several parts of the United States. The devices will have to be tested for several years, however, so that the utilities can determine exactly how the wind generators affect the utilities' total electric system (in terms of stability, reliability, fuels replaced, etc.). Until this testing is complete, it is unlikely that there would be any extensive investment in wind-powered generators. Therefore, their oil replacement potential is relatively small and is likely to remain so until at least 1990.

Solar Thermal Electric Generation

The use of solar thermal energy for electric generation is subject to constraints that are similar to those mentioned above for electricity from wind. Aside from Hawaii, the most favorable region for solar thermal electric generation is in the Southwest, a region where there is considerable generating capacity currently under construction. Unless demand for electricity in that region grows much more rapidly than OTA expects, electricity needs through 1990 could be met and the utility oil use replaced by completing the powerplants currently under construction, converting some utility boilers to coal, and using natural gas in the remaining oil boilers (almost all of which are equipped to burn oil or gas). Even without the coal conversions, all of the oil could be replaced by new powerplants and a modest increase (about 0.04 TCF) in gas use, Hawaiian utilities, however, would continue to use about 20,000 to 30,000 B/D of oil, but this amount of oil is too small for a detailed consideration of solar thermal electric generation.

Electric Vehicles

Except in special applications, the poor performance and low driving range of electric vehicles limit their market and make them most nearly a substitute for very high efficiency conventional cars.[113] In addition, electric vehicles are relatively expensive (compared to other options for displacing oil),[114] and it would take several years to convert automobile production facilities to produce large numbers of these vehicles. Consequently, the oil replacement potential of electric vehicles is relatively small within the timeframe considered for this assessment.

Ethanol From Food Processing Wastes

OTA's earlier assessment of "Energy From Biological Processes" included a survey of various agricultural and food processing wastes.[115] This survey indicated that even if all the largest sources of food processing wastes suitable for conversion to ethanol (cheese whey, tomato pumice, potato peel and pulp, and citrus rag and peel) were converted, the total amount of ethanol produced would be considerably less than the energy equivalent of 10,000 B/D of oil. Although these may be important energy resources in specific localities, their total oil replacement potential is too low for a more detailed consideration in this assessment.

[113] *Increased Automobile Fuel Efficiency and Synthetic Fuels,* op. cit.
[114] Ibid.
[115] *Energy From Biological Processes,* op. cit.

APPENDIX B–ADDITION CONSIDERATIONS REGARDING ETHANOL'S NET ENERGY BALANCE

For average corn production, the oil (for cultivation, harvest, and grain drying) and natural gas (for fertilizers and pesticides) used to produce the corn have an energy content that is about 35 percent of the energy content of the resultant ethanol. For marginal cropland, which is less productive than average cropland, closer to 50 percent of the ethanol's energy content is consumed as oil and natural gas inputs to grain production.[116]

With large increases in corn production, shifts such as the following could also occur. Corn production could increase in Nebraska, at the expense of grain

[116] Ibid.

sorghum production. Production of grain sorghum could then increase in Texas. Assuming that marginal acreage is 70 percent as productive as the average in each State, the net result of this would be to increase agricultural consumption of oil and natural gas by 160 percent of the energy content of the resultant ethanol.[117]

Another aspect of ethanol's energy balance involves potential reductions in refinery energy use through blending ethanol as as octane-boosting additive to gasoline. These savings occur in some refineries by allowing the refiners to reduce the amount of reforming needed to upgrade the octane of their gasoline pool.[118]

While OTA's analysis indicates that gasoline production, as a percent of total refinery products, would be only slightly larger in 1990 than in 1985, diesel production would increase from 62 to 81 percent of middle distillate products (see ch. Vi). The increased diesel production would require additional hydrogen to upgrade the middle distillate fraction. Since this hydrogen normally is produced from reforming a part of the middle distillates to high octane gasoline, the increased demand for diesel would encourage more reforming, thereby reducing the incentive to lower the octane of gasoline being produced. In addition, if the octane of the refinery's gasoline pool were reduced, the hydrogen not produced through reforming would have to be replaced with hydrogen from other sources, such as by reacting residual oil with steam, Although OTA has not conducted a detailed analysis of the effects of ethanol on refinery energy consumption following an oil supply shortfall, it seems likely that, under these circumstances, refinery energy savings from the use of ethanol would be greatly reduced. Clearly there would be exceptions to this general statement for individual refiners, but the average refinery savings associated with 5 billion gallons of ethanol production per year (corresponding to 10 percent ethanol in over half of the gasoline) are likely to be small.

Finally, if ethanol production were expanded much beyond about 2 billion gal/yr, the energy credit for not having to produce soybeans (about 10 percent of the energy content of the ethanol'[119]) would begin to drop, since the soybean substitution market would begin to be saturated with the available distillers' dry grain.

The result of these changes in agricultural energy use and potential energy credits for ethanol production are as follows. If there were a surplus of natural gas, increased use of this fuel in agriculture would not compete with fuel switching from oil to natural gas in other sectors; and the natural gas usage should not be counted as a deficit in terms of oil replacement. In this case, each gallon of ethanol could provide a net oil replacement equal to 40 to 75 percent of the energy content of the ethanol. In other words, 5 billion gal/yr of ethanol could replace 0.08 to 0.15 MMB/D of oil.

On the other hand, if natural gas were in short supply, additional use of it in agriculture would compete with fuel switching to natural gas in other sectors; and the added agricultural use of this fuel would reduce the oil replacement in the other sectors. In this case, ethanol production could result in anything from a net replacement of oil equal to 50 percent of the energy content of the ethanol to a net increase in oil consumption equal to 60 percent of the ethanol's energy content. In other words, the effect of 5 billion gal/yr of ethanol production could vary from reducing oil consumption by 0.1 MM B/D to increasing it by 0.12 MMB/D.

117Based on data from "Energy and U.S. Agriculture: 1974 Data Base," vol. II, U.S. Department of Agriculture, Federal Energy Administration.

118Note that the least sophisticated refineries, which simply distill crude oil into products, cannot achieve these savings because they do not do any reforming. But the use of ethanol by these refiners does increase the fraction of their product which can become gasoline of acceptable octane.

119*Energy From Biological Processes*, op. cit.