Section 3
Capital Requirements of PNGV Fuels Infrastructure

If 3X vehicles require unconventional fuels, a new infrastructure must be developed to supply those fuels in the quantities demanded. That supply infrastructure can be broken down by function: (1) fuel production, which includes the facilities and equipment used to refine and/or process feedstocks into final products, and (2) fuel distribution, which includes the transportation and storage of feedstocks and products at each stage in the production process. Because of the unique characteristics of these two functional areas, estimated capital requirements for PNGV fuels infrastructure have been calculated separately for the two. The methodologies, assumptions, and results of these calculations are discussed below.

3.1 Fuel Production Assumptions

Each fuel evaluated in this study was assumed to supply the energy needs of all 3X vehicles — and only those vehicles — for each year of the analysis.[7] Energy requirements were determined by IMPACTT model runs, which, in turn, were based on vehicle sales and survival modeling and utilization assumptions. These parameters are described in Section 4 of this report. The energy requirement (in gasoline gallon equivalents or GGEs) was then converted into annual demand for each fuel by using the ratio of that fuel's heating value to that of RFG.[8]

An estimate of the physical and capital requirements for production of the requisite volume of fuel was then calculated by determining the scale of production appropriate for the volume demanded and postulating a reasonable timetable for construction of the facilities needed. For each fuel, production was calculated on the basis of a 90% on-stream factor. Production of fuels that also serve as industrial chemicals (e.g., DME) was generally assumed to be incremental to current volumes because motor fuel use will not substantially decrease demand for industrial use. Methanol is a key exception to this, since some reduction in demand for MTBE (as a result of reduced gasoline demand by the non-3X component of the vehicle fleet) can be expected to reduce non-3X demand for methanol, but the impact should not be large given the slow increase in the fleet of 3X vehicles.

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7 Note that sufficient volumes of fuel had to be supplied for each year of the analysis. Inventories could not be used to balance supply and demand. Note also that the demand forecast did not include the fuel requirements of alternative-fuel vehicles (AFVs) that do not achieve 3X fuel economies. These non-3X AFVs were not considered in this analysis.

8 Higher heating values were used here to permit comparison with EIA forecasts of fuel demand. In other parts of the analysis, lower heating values were used to account for differences in the water content of combustion products.

Note that for the capital cost analysis, costs were incremental to a base case of 3X vehicles using RFG. Capital and operating costs for production facilities were developed by using data from the literature, supplemented as needed by technical estimates. The capital cost of production includes the capital cost for any necessary feedstock development (e.g., LNG will require additional gas well development, as well as gas processing and liquefaction equipment). In all cases, capital costs were calculated by using a 10-yr payback and a 10% real interest rate. All costs are in 1995 dollars.

3.1.1 Methanol (M100)

Pathway. In this analysis, all methanol was assumed to be imported and to be made from remote, inexpensive natural gas. Capital cost for development of the natural gas feedstock was assumed to be twice as high as for domestic sources to account for the lack of infrastructure in remote foreign fields. All production was assumed to be via steam-reforming, in which a synthesis gas is produced and then catalytically reformed into methanol. Such processing schemes are used in typical low- to intermediate-pressure methanol synthesis, such as those provided by Lurgi; Imperial Chemical Industries, Ltd. (ICI); and M.W. Kellogg. Steam reforming is an efficient, commercial process well-suited to remote gas fields (Chemical Market Associates, Inc. 1996).

Equipment Requirements. Through 2014, new methanol plants were assumed to have a capacity of 2,500 metric tons per day (MTPD) of methanol. This capacity is consistent with that of current world-scale methanol plants. Starting in 2015, new plants were assumed to have a capacity of 10,000 MTPD. This capacity is consistent with the capacity assumptions used in a prior study by the DOE Policy Office and provides significant economies of scale (U.S. DOE 1991).

Cost. Estimates of capital and operating costs for methanol production were derived from various sources. Fixed and working capital costs were developed by using information from DOE (1991) and Chemical Market Associates, Inc. (1996). Foreign remote-gas feedstocks were assumed to be available for $0.80 per million Btu in 2007. This price was assumed to increase (linearly) by 30% through 2015 and to stabilize thereafter. The latter is consistent with assumptions elsewhere in this report regarding EIA-projected domestic gas prices and world crude oil prices. Specifically, since the 1997 Annual Energy Outlook projected flat or declining energy prices from 2010 to 2015, extrapolated prices were assumed to be flat beyond 2015. Non-feedstock operating costs were derived from Chemical Market Associates, Inc. (1996).

3.1.2 Ethanol (E100)

Pathway. Ethanol was assumed to be produced domestically and to be made exclusively from corn through 2015. Over the 2016–2020 period, an increasing share of newly constructed facilities was assumed to use cellulosic biomass in place of corn. This transition applied *only* to new facilities and occurred at 20% per year (that is, in 2015, 100% of ethanol was produced from corn; in 2016, 80% of the ethanol produced in newly constructed facilities was from corn, etc.). By 2020, all *new* facilities were assumed to be based on cellulosic biomass, although older, corn-based plants continued to produce fuel.

Equipment Requirements. New facilities were initially (2007 through 2010) assumed to be of the dry-milling type, with a grind rate of 36,000 bushels of corn per day (to produce 30.9 million gal of ethanol per year). Beginning in 2011, corn-based facilities were assumed to be of the wet-mill type with a grind rate of 108,000 bushels per day (output of 89.1 million gal of ethanol per year).

All cellulosic ethanol plants were assumed to consume 1,000 bone-dry tons (BDT) of cellulosic biomass per day to produce 35.0 million gal of ethanol per year (for an ethanol yield of about 100 gal/dry ton). These plants are approximately five times larger than the capacity of cellulosic ethanol facilities considered in most other analyses. Larger capacity plants are required by the relatively large fuel demand by 3X vehicles in the period beyond 2015. If not for the higher capacity assumption, over 850 cellulosic ethanol plants of the more typical size would be required by 2030 in the high-market-share scenario.

Cost. Costs were developed from several sources. Capital costs of dry-milling plants were obtained from Stanley Consultants (1996), Liegois (1997), and Donnelly (1997). Capital costs of wet-milling plants were from Stanley Consultants (1996). Non-feedstock operating costs for corn facilities were obtained from Stanley Consultants (1996). The price of corn was assumed to be $2.75 per bushel in all years. Co-product prices were from Morris and Ahmed (1992). Capital, operating, and feedstock costs for cellulosic ethanol plants were obtained from Wiselogel (1996).

3.1.3 LPG

Pathway. Liquefied petroleum gas is produced as a by-product of natural-gas processing and crude-oil refining. At present, a bit more than half of the propane produced domestically[9] comes from natural-gas processing plants. Approximately 7% of the current U.S. LPG supply is imported, much of it from Canada (EIA 1997a; EIA 1997c). For this analysis, the imported fraction was assumed to rise to approximately 40% of LPG supply by 2015 on the basis of the findings of the 502(b) study of the U.S. DOE (U.S. DOE 1996; see Section 3.2.3). Imported LPG was assumed to be produced from natural gas.

Equipment Requirements. LPG is likely to be produced by expansion of petroleum refining and gas processing facilities — the current source of LPG — rather than manufactured in new plants. For this analysis, such expansions in the United States and other LPG exporting countries were assumed to be sufficient to supply LPG for 3X vehicles.

[9] Propane is the fraction of LPG used for motor fuel.

Cost. Capital cost estimates for LPG production facilities were derived from True (1996).

3.1.4 DME

Pathway. DME was assumed to be imported and produced from inexpensive, remote natural gas. The use of inexpensive gas and extremely large production facilities is a key factor in the economic viability of DME production (Fleisch and Meurer 1995).

Equipment Requirements. At present, DME is produced from natural gas via a two-step process in which methanol is produced first. In this analysis, DME was assumed to be produced directly from syngas (e.g., via the Haldor Topsøe/Amoco process). Since DME is not currently used as an automotive fuel, there are no full-scale facilities using this process. However, the scant available literature (Fleisch and Meurer 1995; Hansen et al. 1995) indicates that production volumes on the order of 580 million gal per year (42,000 B/D nameplate with an on-stream factor of 90%) would be necessary to make the process economical. This volume is equivalent to 5,600 MTPD, which is about twice the size of current world-scale methanol plants.

Cost. Capital costs for facilities to produce DME have been estimated only approximately in the literature. The published estimate of $1 billion for plant capital was used for this analysis (Fleisch and Meurer 1995).

Feedstock cost should be comparable with that for methanol and Fischer-Tropsch distillate. The literature on DME indicates that inexpensive natural gas is essential for economically supplying DME (Fleisch and Meurer 1995). In this analysis, the cost of remote natural gas was assumed to be $0.80 per million Btu in 2007, to increase linearly (by 30%) through 2015, and to stabilize beyond 2015.

3.1.5 LNG

Pathway. LNG was assumed to be made by cryogenically liquefying domestic natural gas. Though the process is common and large quantities of LNG are produced in this country and abroad (primarily for storage and transportation of gas), LNG is not currently used in significant quantities as an automotive fuel.

For this analysis, capital costs (i.e., for new wells) for the incremental supply of natural gas needed to satisfy 3X vehicle demand were estimated and attributed to transportation use. (In actual practice, however, incremental development of natural gas resources would likely be cross-subsidized by non-transportation users because of the commodity nature of the fuel. This applies to the *price* of gas, but does not reflect the full *cost* of the resource.)

Equipment Requirements. LNG was assumed to be produced from industrial-quality gas in 75,000-gal/day (gpd) liquefiers.

Cost. Cost estimates were developed from several sources. Capital costs of liquefiers and on-site storage tanks were obtained from Acurex Environmental Corporation (1994). Operating costs were obtained from Nepywoda (1997).

3.1.6 CNG

Pathway. Compressed natural gas was assumed to be produced from domestic resources. This pathway will require the development of additional gas supplies.

Equipment Requirements. New wells and gas processing plants will be needed to produce the incremental gas required to supply 3X vehicles.

Cost. The costs of additional wells, processing plants, and connections to major pipelines were estimated. These costs include both non-productive and productive wells. To develop these cost estimates, historical counts of domestic producing wells, new wells drilled, dry and productive wells, and average drilling cost per well were obtained from EIA (1996c) and the American Petroleum Institute (API 1995).

3.1.7 Hydrogen

Pathway. Hydrogen was assumed to be produced domestically, in centralized production facilities, throughout the analysis. From 2007 to 2020, all hydrogen was assumed to be made by steam reforming of natural gas. Beginning in 2021, an increasing share of new production was assumed to use solar-powered electrolysis of water. This process was assumed to be phased in over five years, accounting for an additional 20% of new capacity per year. As a result, 61% of all hydrogen was supplied by solar electrolysis in 2030 under the high-market-share scenario.

Equipment Requirements. Steam reforming of natural gas is a commercial technology. When solar electrolysis is introduced, photo-voltaic (PV) arrays and electrolyzers are the major pieces of capital equipment to be considered. The output of a typical solar hydrogen facility was assumed to be 100 million scf/day. Such a plant would be modular, consisting of several separate electrolyzer units, each rated at 100 MW. Solar arrays sufficient to supply approximately 500 MW of electricity to the electrolyzers have been assumed for each plant. Because of the intermittent nature of the solar resource, PV array capacity for a given plant would depend on location.

Cost. Reformer capital and operating costs were adapted from Blok et al. (1996). Costs for PV arrays and electrolyzers were obtained from Ogden and Delucchi (1993).

3.1.8 Biodiesel

Pathway. Biodiesel was assumed to be produced domestically from soybean oil in this study. Cheaper, higher-oil-content feedstocks (e.g., rapeseed oil) are being investigated in Europe; however, in the United States, the political climate is likely to favor soybean oil.

Soy diesel (methyl ester of soybean oil, or methyl soyate) was assumed to be mixed with 80% reformulated diesel to make a 20% blend of soy diesel fuel (B20). A credit for the by-product glycerine is important in estimating the cost of biodiesel (Flechtner and Gushee 1993). For this analysis, the price of glycerine was assumed to decline to \$0.50/lb (about half of the 1997 price) after introduction of biodiesel, significantly reducing the value of the glycerine credit. Because of the limited market for glycerine, such a reduction in value over the course of the analysis is not unreasonable.

Equipment Requirements. Individual plants were assumed to produce approximately 3 million gal of methyl soyate per year (Gavett 1995). This amount is considerably less than the output of corn ethanol plants.

Cost. Capital and operating cost estimates were obtained from Gavett (1995). Feedstock is by far the largest cost component, representing approximately 75% of the cost of methyl ester (Booz-Allen & Hamilton 1994). Thus, little reduction in the cost of biodiesel is likely to come as a result of economies of scale or reductions in processing costs.

3.1.9 Fischer-Tropsch Diesel

Pathway. A 50% blend of Fischer-Tropsch distillate and reformulated diesel (F-T50) was assumed in this analysis. Blending of F-T diesel and petroleum diesel takes advantage of the F-T diesel's inherently low aromatics, low sulfur, and high cetane and reduces the burden on petroleum diesel to achieve mandated reductions in aromatics and sulfur. The reformulated diesel component of FT-50 was assumed to be derived from crude oil. The Fischer-Tropsch component was assumed to be imported and derived from remote natural gas.

Equipment Requirements. A F-T plant using the Shell Middle Distillate Synthesis process (Choi et al. 1996; Kramer 1997) was modeled. Although the process makes significant quantities of high-quality gasoline in addition to distillate, costs were attributed entirely to the desired distillate product. F-T plants were assumed to be built close to large, remote gas fields. As product demand increased, larger plants were assumed to predominate. Thus, by 2030, all plants were assumed to be either 50,000 or 100,000 B/D.

Cost. Costs were developed for three different plant sizes. Costs for a 100,000-B/D plant were from Singleton (1997) and Knott (1997). Costs for a 50,000-B/D plant were from Frank (1997), Singleton (1997), and Choi et al. (1996). Costs for a 5,000-B/D plant were from Singleton (1997) and Choi et al. (1996). Engineering cost estimates were calculated using RS Means Cost Guide (R.S. Means Company, Inc. 1996) and McKetta (1992).

3.1.10 Reformulated Gasoline and Reformulated Diesel

Capital costs of RFG and RFD were not estimated per se. Rather, both were assumed to be conventional fuels for which investment expenditures were already included within the reference case. Industry investment in refining was assumed to remain in its historical range of $3–6 billion per year over the course of the analysis (Energy Statistics Sourcebook 1995). Table 3.1 presents a breakdown of the U.S. petroleum industry's annual capital expenditures for the past 25 years.

Table 3.1 Domestic Capital Expenditures of the U.S. Petroleum Industry ($ billion)

Year	Refining	Exploration & Production	Marketing & Transportation	Other	Total Capital Expenditures
1973	1.104	7.212	1.818	0.916	11.050
1974	2.446	10.889	2.479	2.088	17.902
1975	1.981	9.915	4.576	2.152	18.624
1976	1.819	12.266	4.576	3.162	21.823
1977	1.324	18.400	3.628	3.339	26.691
1978	1.551	19.978	3.248	4.413	29.190
1979	2.735	31.495	4.434	6.055	44.719
1980	3.159	42.185	7.499	7.827	60.670
1981	5.131	57.830	9.513	10.523	82.997
1982	4.710	56.919	9.242	9.378	80.249
1983	4.142	39.473	9.233	5.679	58.527
1984	2.914	36.909	8.267	5.562	53.652
1985	2.992	33.371	6.290	5.199	47.852
1986	2.073	17.904	3.758	4.615	28.350
1987	2.180	14.171	4.409	4.428	25.188
1988	2.874	17.455	5.000	5.419	30.748
1989	3.167	15.481	4.531	6.226	29.405
1990	4.402	16.630	5.831	7.157	34.020
1991	6.741	17.462	6.603	5.922	36.728
1992	6.795	14.681	7.266	5.507	34.249
1993	5.367	13.909	7.191	5.051	31.518
1994	5.082	14.672	5.376	5.413	30.543
1995	4.903	15.775	5.442	6.361	32.481
1996	3.932	18.187	5.331	5.795	33.245
1997	3.907	20.096	5.901	5.899	35.803
Average	3.497	22.931	5.658	5.363	37.449

Sources: 1973–94: Energy Statistics Sourcebook, 1995. 1995-97: Oil and Gas Journal, 1997.

Because feedstock currently represents 70–75% of the price of gasoline and diesel, per-gallon costs of RFG and RFD were estimated as a function of the projected price of crude oil (EIA 1996a), with appropriate adjustments for future investment requirements. Both RFG and RFD were assumed to have a sulfur level of 100 ppm in this analysis. For gasoline, increased desulfurization was assumed to add $0.04/gal; for diesel, meeting this sulfur specification was assumed to add $0.08/gal. The higher diesel desulfurization premium reflects the higher cost (including more capital investment and higher operating pressures) of distillate hydrotreating relative to naphtha hydrotreating.

3.2 Fuel Distribution Assumptions

A five-step process was used to estimate costs associated with establishing PNGV fuels distribution infrastructure. First, the distribution system was characterized from production plant to refueling station for each potential PNGV fuel. This characterization and the known capabilities of the existing gasoline and diesel fuel distribution systems were then used to determine the extent to which existing systems could be modified to accommodate each new fuel. Third, based on estimated fuel demand by 3X vehicles (see Section 2), the requisite number of distribution and storage facilities (such as ocean tankers, storage tanks, trucks, and refueling stations, and pipeline miles) was estimated for each fuel in each year. Fourth, unit costs were estimated for each type of distribution equipment. Finally, annual capital requirements were calculated by assuming a 10-yr payback period and a 10% interest rate (in real-dollar terms). For hydrogen and NG pipelines, a sensitivity case, assuming a 50-yr payback period, was tested.

Tables 3.2–3.6 present the key assumptions used to estimate the size and capital cost of developing distribution systems for each of the candidate 3X fuels. The five tables are organized by stage in the fuel pathway. Assumptions regarding equipment requirements and costs of moving imported liquid fuels from overseas production centers to marine and inland terminals are presented in Table 3.2. Similar assumptions for moving domestically produced liquid fuels from domestic production centers to bulk terminals are presented in Table 3.3. Table 3.4 contains assumptions regarding equipment requirements and costs of moving all these liquid fuels from domestic inland and bulk terminals to service stations, while Table 3.5 contains comparable assumptions for moving gaseous fuels from domestic production centers to service stations. Finally, Table 3.6 presents the costs of adapting service stations to dispense the candidate fuels.

Several assumptions cut across all fuels. First, each service station that dispenses an alternative fuel was assumed to have originally dispensed 150,000 gal gasoline/month. Each such station was assumed to be converted to dispense 100,000 gal gasoline/month and 50,000 gasoline-gallon equivalents (GGE) per month of the alternative fuel. Use of this assumption facilitates comparisons among the fuels.

Second, with the exception of trucks, all equipment was assumed to have a useful life longer than the period of analysis (i.e., 2007–2030 for the high-market-share scenario

Table 3.2 Key Assumptions Relative to Transportation of Imported Fuels

Assumption	Methanol	DME	LPG
Imported ?	Yes	Same	Same
Percent imported	100	100	Varies over time: see text
Ocean Tankers ?	Yes	Same	Same
Capacity (million gallons)	20.4	Same	Same
Round-trips/yr	8	Same	Same
Conversion of existing tankers?	No	Same	Same
New tanker cost ($, millions)	41.2	Same	Same
Marine terminals ?	Yes	Same	Same
No. of marine terminals available	116	Same	Same
Turnover rate of storage tanks (number of times/yr)	18	Same	Same
Cost of converting existing tank ($/bbl)	3	NA	NA
New tank cost ($/bbl)	18	36	36
No. of truck racks/terminal	1	Same	Same
Truck rack cost ($, millions)	1.4	Same	Same
Truck movement from marine terminals ?	Yes	Same	Same
Trucks move first MMBD GGE to service stations?	Yes	Same	Same
Truck capacity (thousand bbls/yr)	240	Same	Same
Cost of converting existing truck ($000)	0	NA	NA
New truck cost ($000)	151	Same	Same
Pipeline movement from marine terminals ?	Yes	Same	Same
Pipelines move all imported fuel above 1 MMBD GGE to inland terminals?	Yes	Same	Same
Throughput volume (million bbls/yr)	80	Same	Same
Cost of converting existing pipeline ($000/mi)	40	NA	NA
New pipeline cost ($000/mi)	396	530	530
Average pipeline distance (mi)	547	Same	Same
Storage at inland terminals ?	See Table 3.4	Same	Same

Same = Used where values/answers for all fuels are the same. NA = Not applicable.

and 2012–2030 for the low-market-share scenario). Trucks, the key exception, were assumed to be replaced every 15 years.[10]

Third, all costs are in 1995 dollars. Costs were converted to 1995 dollars by using either the consumer or producer price index (as appropriate).

[10] Some of the equipment converted to handle the new fuel may be of an age where routine replacement or upgrade would be expected during the period of the analysis. Thus, one might argue that expenditures programmed for replacement or upgrade of gasoline distribution equipment would not be needed if alternative fuels were supplied instead of gasoline. The avoided cost of expanding the gasoline distribution system (to meet the larger demand forecast under a reference scenario without 3X vehicles) could be a legitimate offsetting cost. However, avoided costs were not considered in this analysis.

Table 3.3 Key Assumptions Relative to Transportation of Domestically Produced Liquid Fuels

Assumption	Ethanol	Methyl Soyate	LNG	LPG
Movement from domestic production centers to bulk terminals ?	Yes	Same	Same	Same
Percent by pipeline, barge, rail, truck	48/12/40/0	63/8/29/0	Initially all by truck; later rail & truck; see text	60/6/34/0
Movement by pipeline ?	Yes	Yes	No	Yes
Minimum fuel volume required before movement by pipeline begins?	Yes	No	NA	Yes
Minimum volume required (million bbls/yr)	80	NA	NA	80
Alternative mode until minimum met	Truck	NA	NA	Truck
Throughput volume (million bbls/yr)	80	NE	NA	80
Cost of converting existing pipelines ($000/mi)	0	0	NA	NA
New pipeline cost ($000/mi)	396	NA	NA	530
Average pipeline distance (mi)	564	NE	NA	604
Movement by barge ?	Yes	Yes	No	Yes
New tugboats required?	No	No	NA	No
Barge capacity (thousand bbls/yr)	1260	NE	NA	1130
Cost of converting existing barges	0	0	NA	NA
New barge cost ($000)	1260	NA	NA	1260
Movement by rail ?	Yes	Same	Same	Same
New locomotives or track required?	No	Same	Same	Same
Existing excess fuel-specific rail car capacity ?	No	No	No	Yes: see text
Rail car capacity (thousand bbls/yr)	109	129	194	420
New rail car cost ($000)	70	70	324	79
Movement by truck ?	Yes	No	Yes	Yes
Truck capacity (thousand bbls/yr)	240	NA	240	240
Cost of converting existing truck ($000)	0	NA	NA	NA
New truck cost ($000)	151	NA	372	151
Storage at bulk terminals ?	See Table 3.4	Same	Same	Same

Same = Used where values/answers for all fuels are the same. NA = Not applicable. NE = Not estimated because not necessary.

Finally, all costs are incremental to a baseline or business-as-usual level. Specifically, while the capital costs of providing new equipment or converting existing equipment are included, the costs of constructing the original gasoline distribution system are not.

3.2.1 Methanol (M100)

Pathway. Methanol is a liquid at normal temperatures and pressures and thus can be moved through the existing gasoline-distribution system, although some modifications will be required. As stated in Section 3.1, methanol was assumed to be made in foreign,

Table 3.4 Key Assumptions Relative to Storage of Liquid Fuels at Inland and Bulk Terminals and Subsequent Distribution to Service Stations

Assumption	Methanol	DME	LPG	Ethanol	Methyl Soyate	LNG
Storage at inland and bulk terminals ?	Yes	Same	Same	Same	Same	Same
Capacity per terminal (thousand bbls)	300	Same	Same	Same	Same	Same
Turnover rate of storage tanks (number of times/yr)	18	18	18	18	18	24
Cost of converting existing tank ($/bbl)	3	NA	NA	3	3	NA
New tank cost ($/bbl)	18	36	36	18	NA	102
No. of truck racks/terminal	1	1	1	1	NA	1
Truck rack cost ($, millions)	1.4	1.4	1.4	1.4	NA	1.4
Truck movement to service stations ?	Yes	Yes	Yes	Yes	Only as B20	Yes
Truck capacity (thousand bbls/yr)	240	240	240	240	NE	240
Cost of converting existing truck ($000)	0	NA	NA	0	NE	NA
New truck cost ($000)	151	151	151	151	NE	372
Service stations ?	See Table 3.6	Same	Same	Same	Same	Same

Same = Used where values/answers for all fuels are the same. NA = Not applicable. NE = Not estimated because not necessary.

Table 3.5 Key Assumptions Relative to Transportation of Domestically Produced Gaseous Fuels

Assumption	CNG	H_2
Movement to service stations by pipelines ?	Yes	Same
Percent moved by pipeline	100	Same
Can existing natural gas pipeline capacity be used?	Only a limited amount: see text	No
New pipeline capacity required (thousand miles/TCF)	76	Same
New pipeline cost ($/mile, thousands, average for all types)	615	1000
Service stations ?	See Table 3.6	Same

Same = Used where values/answers for all fuels are the same.

Table 3.6 Capital Cost of Adapting Service Stations to Dispense 50,000 GGE of Alternative Fuel per Month (1995$)

Fuel	Cost/Station ($\$10^3$)
Methanol	182
Ethanol	170
DME	261
LPG	204
CNG	928
Hydrogen	1,423
LNG	600
Biodiesel	0

remote areas where inexpensive NG will be available. Methanol would then be transported by ocean tanker to marine terminals in major U.S. ports. Because of unresolved technical problems (e.g., the potential for water pickup by methanol, cross-contamination of products, and materials compatibility), the initially small volumes of methanol shipped from marine terminals to service stations were assumed to be by truck rather than pipeline. Technical problems were assumed to be resolved by the time methanol displaces 1 MMBD of gasoline. At that scale, movement by pipeline from ports to inland bulk terminals should be economical.[11] At both low and high distribution volumes, the final leg in the distribution network, delivery from bulk terminals to service stations, would be by truck. (Some fuel would also be distributed from terminals to smaller bulk plants instead of going directly by truck to service stations. This possibility was not characterized.)

Figure 3.1 shows the methanol distribution system. Tables 3.2, 3.4, and 3.6 presented key assumptions used to characterize that system. Additional assumptions used to estimate equipment requirements and costs of methanol distribution are described below.

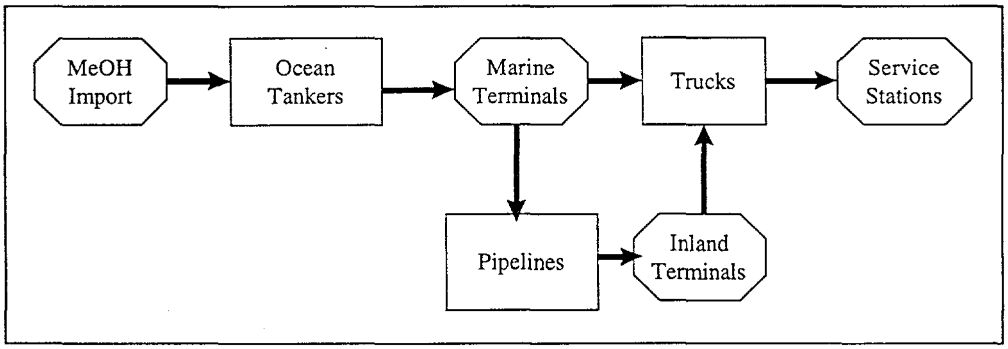


Figure 3.1 Methanol Distribution System

Equipment Requirements. Some gasoline distribution equipment was assumed to be converted to move methanol: trucks, storage tanks at marine and inland terminals, and, eventually, pipelines. This equipment can be converted because use of methanol will reduce gasoline distribution requirements. However, because twice as much (in

[11] Although this threshold may seem high, a prior analysis estimated that 75% of total U.S. travel is within 100 mi of existing marine terminals and can easily be served by truck distribution (U.S. DOE 1990).

physical volume) methanol is required to provide the same energy as gasoline, some new trucks, storage tanks, and pipelines would also be needed.

It was assumed that all ocean tankers used to transport imported methanol would be new (i.e., existing crude carriers would not be modified to ship methanol). This assumption is based on a prior DOE analysis (U.S. DOE 1989) that questioned whether existing tankers could be adequately cleaned, the amount of internal equipment that would need to be replaced, and the age of the tankers available for conversion.

For this analysis, it was assumed that new truck racks would be required at each marine terminal because of the significantly increased methanol fuel volumes that must be handled and to avoid cross-contamination of products. A prior analysis (U.S. DOE 1990) estimated that 116 existing marine terminals could be used for methanol imports. While somewhat dated, this estimate is still reasonable. Similarly, it was assumed that new truck racks would be needed at each inland terminal. An average capacity of 300,000 bbls (EEA 1990) was used to calculate the required number of inland terminals (and thus truck racks) for this analysis.

Existing gasoline service stations were assumed to be adapted to dispense approximately 100,000 gal/month methanol (50,000 GGE) and 100,000 gal/month gasoline. A prior analysis evaluated the service station equipment changes needed to dispense 50,000 GGE of M85/month at a total capacity of 150,000 GGE/month per service station. Equipment changes included, for example, additional refueling positions, new and modified hose dispensers, and new and displaced underground tanks (EEA 1995). Equipment changes estimated for this analysis of M100 fuel were adapted from that earlier analysis.

Cost. Capital cost estimates for the methanol distribution system were derived from several sources. Costs for new ocean tankers, averaging 60,000 dead-weight tons (DWT), were obtained from U.S. DOE (1989) and Zebron (1997). Costs for new and converted tanks at marine and inland bulk terminals were obtained from U.S. DOE (1990), as were costs for new truck racks. Costs for new trucks were from EA Energy Technologies Group (1991). On the basis of this latter study, it was assumed that there are virtually no costs associated with converting existing gasoline trucks to distribute methanol. Costs for new pipelines were from EA Energy Technologies Group (1991), while costs for converting an existing pipeline were assumed to be one-tenth the cost of constructing a new pipeline. Costs for conversion of service stations to dispense 50,000 GGE methanol were from EEA (1995).

3.2.2 Ethanol (E100)

Pathway. Like methanol, ethanol is liquid at normal temperatures and pressures and can be moved through the existing gasoline-distribution system, although some minor modifications may be required. Compared with methanol, ethanol's higher heat content provides an important advantage — approximately one-third less product must be moved to provide the same energy. As stated in Section 3.1, ethanol was assumed to be produced domestically. Movement from production centers to bulk terminals was assumed to be primarily by pipeline and rail. This assumption is consistent with a previous analysis (EA Energy Technologies Group 1991) that estimated that nearly 50% of ethanol distribution could be by pipeline and 40% by rail. In this analysis, trucks were assumed to play a somewhat larger role in ethanol distribution — for bulk movement until volumes reach the levels required to support movement by pipeline, as well as for delivery[12] from bulk terminals to service stations.

Figure 3.2 illustrates the ethanol distribution system. Tables 3.3, 3.4, and 3.6 presented key assumptions used in characterizing that system. The assumptions underlying the equipment requirements and costs of ethanol distribution are described below.

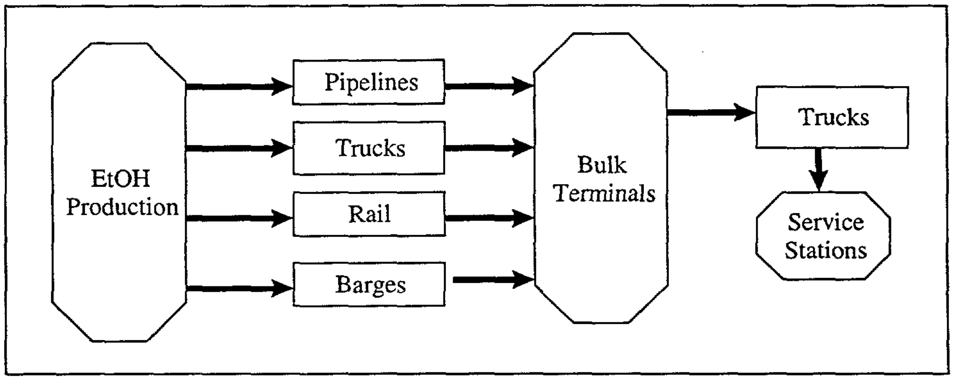


Figure 3.2 Ethanol Distribution System

Equipment Requirements. As with methanol, some gasoline distribution equipment — including pipelines, barges, trucks and storage tanks at bulk terminals — can be converted to move ethanol. This equipment can be converted because ethanol will reduce gasoline distribution requirements. However, because one gallon of ethanol contains about one-third less energy than a gallon of gasoline, 1.5 gal of ethanol is required to replace one gallon of gasoline. So, in addition to the converted equipment, new pipelines, barges, trucks, and storage tanks are also required.

All rail cars were assumed to be new (gasoline is not currently moved by rail; therefore, there are no gasoline rail cars to convert). No new locomotives or track should be needed, but new truck racks were assumed to be required at each bulk terminal. The number of bulk terminals was calculated by assuming an average capacity of 300,000 bbls per terminal (like methanol's inland terminals).

EEA has evaluated the equipment changes needed to permit gasoline service stations to dispense approximately 75,000 gal/month ethanol (50,000 GGE E85) and

[12] Some fuel may be distributed from terminals to smaller bulk plants instead of going directly by truck to service stations. This part of the pathway was not characterized in this analysis.

100,000 gal/month gasoline. Changes included, for example, additional refueling positions, new and modified hose dispensers, and new and displaced underground tanks (Energy and Environmental Analysis 1995). For this study, EEA's analysis was adapted to estimate the equipment changes required for E100.

Cost. Capital cost estimates were derived from several sources. Costs for new pipelines were obtained from EA Energy Technologies Group (1991). Unlike methanol, the cost for converting an existing pipeline was assumed to be zero (likewise for converting an existing barge or truck). Costs for new rail cars and barges were obtained from EA Energy Technologies Group (1991) and Zebron (1997), respectively. Costs for new trucks were from EA Energy Technologies Group (1991). Costs for new and converted tanks and truck racks at bulk terminals were obtained from U.S. DOE (1990). Conversion costs for service stations to dispense 50,000 GGE of ethanol per month were from Energy and Environmental Analysis (1995).

3.2.3 LPG

Pathway. LPG is a gas at normal temperatures and pressures, but it can be stored in liquid form under modest pressure. Although it is possible that some displaced gasoline infrastructure capacity might be converted to LPG use (e.g., pipelines, since gasoline pipelines operate under pressure), prior analyses (e.g., EA Energy Technologies Group 1992) generally have assumed that gasoline facilities will not be converted to LPG. The current LPG distribution system has excess off-peak capacity because of fluctuations in seasonal demand. However, this "excess capacity" is needed to handle peak LPG demand; thus (except where noted below), it was not assumed to be available to move or store LPG for 3X vehicles.

A mix of both imported and domestic LPG was assumed to supply the fuel needs of 3X vehicles. Except for Canadian imports, imported LPG was assumed to be shipped by ocean tanker. EIA's AEO 1997 (EIA 1996a) estimated that in 1996 approximately 3% of all U.S. LPG was from non-Canadian imports. By 2015, EIA forecasts that percentage to triple, to about 9% (under the EIA reference case, that is, no LPG demand by 3X vehicles). In this analysis, EIA's imported and domestic shares were used through 2015. Beyond 2015, imported market shares must include a growing component of transportation sector fuel use. For this analysis, that component was supplied by results of a recent DOE study on the market potential of alternative fuel use by motor vehicles (DOE 1996). In one case of that study, non-Canadian imports accounted for about 40% of the transportation sector's use of LPG (1.7 MMBD LPG) in 2015. Thus, in this analysis, the shares of non-Canadian imports were interpolated between 9% (for volumes of transportation sector LPG use of 159,000 bbl/d, EIA's 2015 estimate) and 40% (for 1.7 MMBD transportation sector LPG use).

As in the methanol analysis, trucks were assumed to move imported LPG from marine terminals to service stations until LPG displaces 1 MMBD of gasoline. At that point, pipelines were assumed to enter the LPG distribution network, moving the fuel to inland terminals from which trucks would deliver it to service stations. In reality, however, even under the high-market-share scenario, the volume of imported LPG never reaches 1 MMBD. Thus, no pipeline movement was assumed for imported LPG.

For domestically produced LPG, 60% was assumed to be moved from production centers to bulk terminals by pipeline, 34% by rail, and the rest by barge. These shares were based on a prior analysis of LPG movement (EA Energy Technologies Group 1992). Trucks were assumed to move LPG until volumes are sufficient to support the construction of one pipeline from domestic production centers. Trucks were also assumed to be used to complete the delivery of LPG from bulk terminals to service stations. As with other fuels, some fuel may also be distributed from terminals to smaller bulk plants instead of going directly by truck to service stations. This part of the pathway was not included in this analysis.

Figure 3.3 illustrates the LPG distribution system. Tables 3.2–3.4 and 3.6 presented key assumptions used to characterize that system. The assumptions underlying the equipment requirements and costs of LPG distribution are described below.

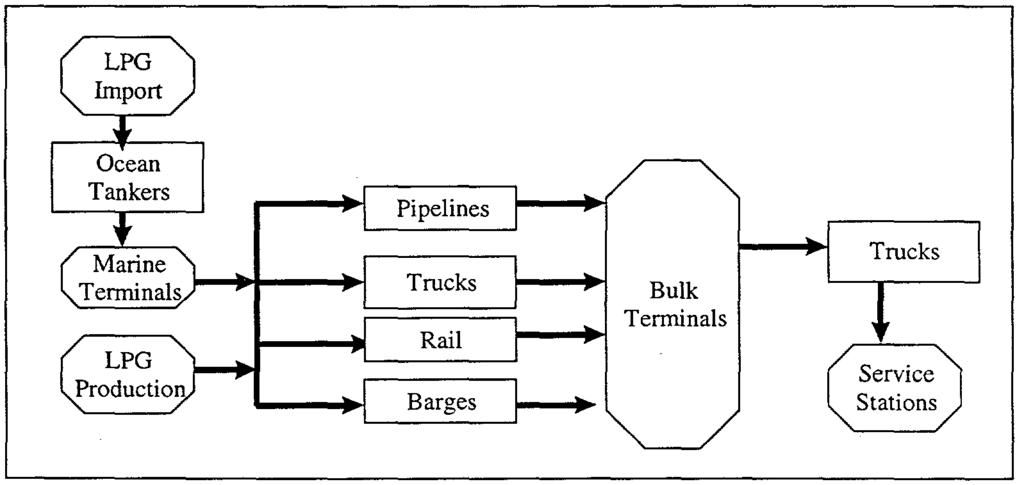


Figure 3.3 LPG Distribution System

Equipment Requirements. With the exception of rail tank cars, the LPG fuel distribution system (from ocean tankers to trucks) was assumed to be entirely new. A prior analysis by EA Engineering (EA Energy Technologies Group 1992) found that the current population of LPG rail tank cars is very large, with sufficient excess capacity to move over 80 million bbl/yr. This excess capacity is well above the volumes of LPG projected to be moved by rail in the low-market-share scenario and until the latter years in the high-market-share scenario. Thus, new rail cars are only required in the outyears of the high-market-share scenario.

Again, service stations were assumed to be converted so that the equivalent of 50,000 GGE of LPG per month could be dispensed. All LPG-specific equipment at service stations was assumed to be new.

Cost. The capital cost estimates for LPG were derived from several sources. The costs of LPG ocean tankers were approximated from the costs of methanol tankers. LPG tankers are likely to be somewhat more expensive (because LPG is stored under pressure), but no information on the cost difference is available. Costs for new and converted tanks at marine, inland and bulk terminals, for new pipelines, and for new rail cars were obtained from EA Energy Technologies Group (1992). Costs for new truck racks and new trucks were from U.S. DOE (1990) and EA Energy Technologies Group (1991), respectively. Costs for new barges were from Zebron (1997). Finally, costs for conversion of service stations to dispense 50,000 GGE of LPG were from EEA (1995).

3.2.4 DME

Pathway. The DME fuel distribution system was assumed to be very similar to that for imported methanol and LPG. Like methanol and LPG, DME was assumed to be shipped on ocean tankers to marine terminals and then transported by truck to service stations until it displaces 1 MMBD gasoline. Beyond this level, DME was assumed to be moved by pipeline to inland terminals and then by truck to service stations. Figure 3.4 illustrates the DME distribution system. Tables 3.2, 3.4, and 3.6 presented key assumptions for the DME pathway. The assumptions underlying the equipment requirements and costs of DME distribution are described below.

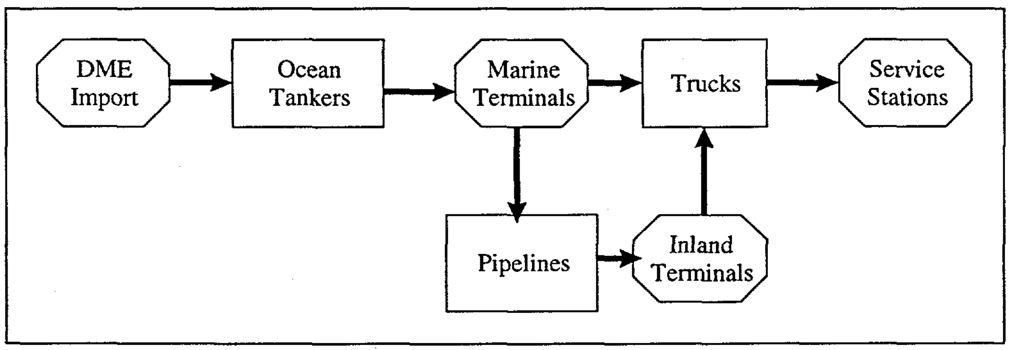


Figure 3.4 DME Distribution System

Equipment Requirements. The physical properties of DME are similar to those of LPG. Like LPG, DME can be stored in liquid form under modest pressure. Because little information exists on DME handling and distribution, DME equipment requirements were approximated on the basis of LPG equipment requirements.

As with LPG, some displaced gasoline infrastructure capacity could be converted to distributing DME. However, as in the LPG analysis, it was assumed that conversion of gasoline infrastructure would not occur. Although DME could make use of converted LPG facilities, this analysis assumed that DME would replace gasoline, not LPG. Thus, all DME fuel distribution requirements (tankers, trucks, pipelines, etc.) were assumed to be new.

Again, gasoline service stations were assumed to be converted to dispense 50,000 GGE of DME per month. All DME-specific equipment at service stations was assumed to be new.

Costs. Except for the cost of converting service stations, capital costs for DME distribution equipment were assumed to equal those for LPG. Because the heating value of DME is approximately 81% that of LPG, nearly 25% more DME must be supplied to equal the energy in 1 gal of LPG (which is roughly equivalent to the energy in 0.75 gal of gasoline). Therefore, the pumps, tanks, and other equipment at service stations dispensing 50,000 GGE DME will require 25% additional capacity, as compared with an energy-equivalent volume of LPG. Thus, EEA's estimate of LPG station conversion cost (EEA 1995) was adapted to develop an estimate for DME station conversions.

3.2.5 LNG

Pathway. LNG was assumed to be produced domestically at centralized production facilities. Because of the need for cryogenic storage, distribution was assumed to be via a separate distribution system (i.e., neither the existing gasoline nor natural gas distribution systems would be used), not unlike the situation today. In the United States, small volumes of LNG are currently moved by truck, and rail shipment to bulk terminals may soon begin. For this analysis, it was assumed that LNG would continue to be moved by these modes from central production facilities to bulk terminals and then to service stations by truck. Because of the lack of prior analyses of the potential mode split of LNG movements, it was assumed that the initial 0.5 MMBD of LNG would be moved solely by truck. When LNG demand exceeds that level, it was assumed that two-thirds of the incremental movement would be by truck and one-third by rail. By using these assumptions, approximately one-fourth of total LNG demand was assumed to be moved by rail in 2030 under the high-market-share scenario.

Figure 3.5 shows the LNG distribution system. Tables 3.3, 3.4, and 3.6 presented key assumptions used to characterize that system. The assumptions underlying the equipment requirements and costs of LNG distribution are described below.

Equipment Requirements. As indicated above, all facilities and equipment required to move LNG were assumed to be new (trucks, rail cars, storage tanks, etc.). Again, service station conversions were assumed to dispense 50,000 GGE of LNG and

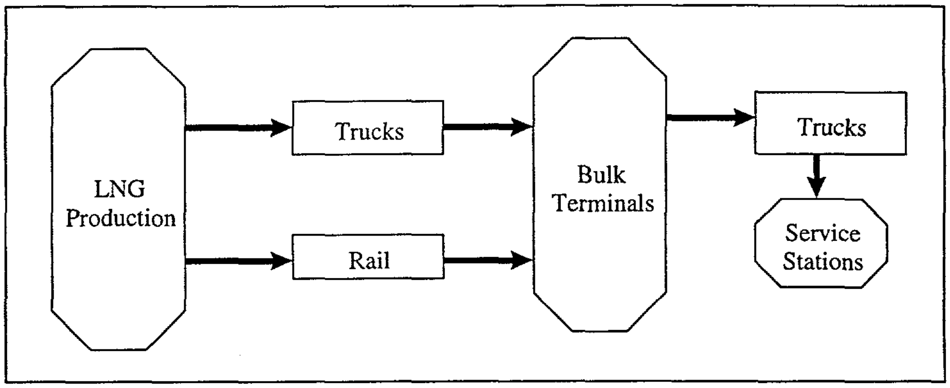


Figure 3.5 LNG Distribution System

100,000 gal of gasoline per month. All LNG-specific equipment at service stations was assumed to be new.

Cost. Capital cost estimates for LNG were derived from several sources. Costs for new trucks and new rail cars were obtained from Acurex (1992 and 1994). Costs for new truck racks were from U.S. DOE (1990). Costs for conversion of service stations to dispense 50,000 GGE of LNG were adapted from estimates developed by Acurex Environmental Corporation for other LNG volumes (1992).

3.2.6 CNG

Pathway. All natural gas was assumed to be produced domestically and moved by pipeline to service stations. The existing natural gas distribution system was assumed to be used, with capacity added to meet demand increases over time. Figure 3.6 illustrates the CNG distribution system. Tables 3.5 and 3.6 presented key assumptions for the CNG pathway. The assumptions underlying the equipment requirements and costs of CNG distribution are described below.

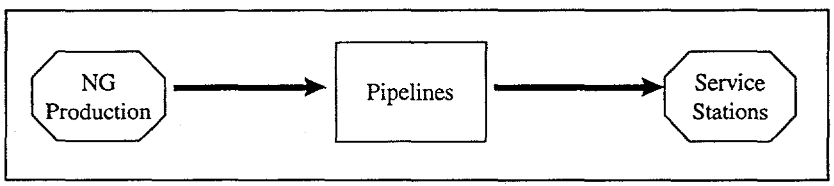


Figure 3.6 Natural-Gas Distribution System

Equipment Requirements. It was assumed that new pipeline capacity would be required once motor-vehicle demand exceeded 0.31 trillion cubic feet (TCF). This threshold was based on EIA's AEO 1997, which forecast 0.31 TCF motor-vehicle use of CNG in 2015 out of total U.S. NG demand of 30 TCF. Because EIA projected capacity additions to the NG pipeline system to meet these demand levels, vehicular demand for CNG above those levels (e.g., all CNG demand by 3X vehicles reaches 2.7 TCF in the high-market-share scenario) was assumed to require even more capacity additions.

In the late 1980s, there were 250,000 mi of transmission lines, 900,000 mi of main distribution lines, and 520,000 mi of service lines capable of moving 22 TCF (EA Mueller 1991; R.F. Webb Corporation 1992). Assuming a linear relationship between pipeline mileage and the volume of NG delivered, new capacity should be required at the rate of 76,000 mi/TCF (1.67 million mi/22 TCF). Although a linear relationship may be overly simplistic, a detailed micro-level analysis would be required to develop a more accurate assessment of the length and size of pipelines required to support the additional natural gas movement. Such analysis is beyond the scope of this effort.

Pipeline expansion typically requires additional storage facilities, which may or may not be included in pipeline cost estimates. Some of the costs cited below for the NG distribution system clearly include expanded storage facilities; for others, it is not clear whether such costs are included. This analysis assumed that pipeline costs included additional storage and thus did not specifically account for expanding storage capacity.

Again, gasoline service stations were assumed to be converted to dispense 50,000 GGE of CNG per month. All CNG-specific equipment at service stations was assumed to be new.

Cost. Capital cost estimates for CNG were derived from several sources. NG pipeline costs vary by size of pipeline, distance, and location. For this analysis, it was assumed that transmission lines would be 32 in. in diameter, distribution lines would be 12 in., and service lines would be 2 in. (Williams 1996). Distance and location were assumed to be comparable to historical patterns. Thus, transmission lines were assumed to cost $900,000/mi, main distribution lines were assumed to cost $780,000/mi, and service pipelines were assumed to cost $190,000/mi (EA Mueller 1991; Williams 1996). Using the historical share of mileage by the three pipeline types, a weighted-average cost of new NG pipeline was calculated at $615,000/mi.

The cost of converting a gasoline service station to dispense 50,000 GGE of CNG was obtained from EEA (1995).

3.2.7 Hydrogen

Pathway. All hydrogen required by 3X vehicles was assumed to be produced in the United States from natural gas and solar electrolysis of water and to be moved in gaseous form (by pipeline) from central production facilities to service stations. An all-new distribution system was assumed; no existing facilities (e.g., no NG distribution facilities) would be converted. Figure 3.7 characterizes the H_2 distribution system. Tables 3.5 and 3.6 presented key assumptions for the pathway. The assumptions underlying the equipment requirements and costs of H_2 distribution are described below.

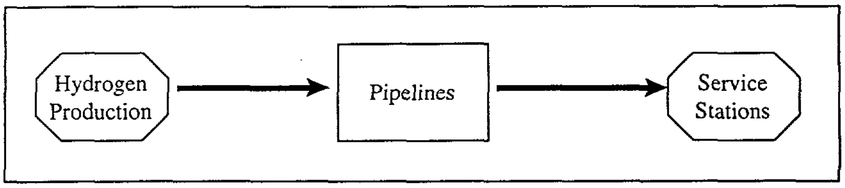


Figure 3.7 Hydrogen Distribution System

Equipment Requirements. As indicated above, the entire pipeline distribution system was assumed to be new. Pipeline miles were assumed to equal the number estimated for the CNG pipeline system, but at increased compression. H_2 pipelines of the same length and size can carry the same amount of energy as NG pipelines, but the required compressor capacity is much greater (3.0–3.5 times as great) because a cubic foot of H_2 contains far less energy than a cubic foot of NG at normal temperature and pressure. H_2 storage requirements were assumed to be much less than those for NG because seasonal demand for hydrogen for transportation use should vary far less than the seasonal demand for NG.

Again, gasoline service stations were assumed to be converted to dispense 50,000 GGE of H_2 per month. All H_2-specific equipment at service stations was assumed to be new.

Cost. Capital cost estimates for H_2 were derived from several sources. The cost of H_2 pipelines (including compressors) was based on work by Williams (1996) and Ogden et al. (1997). According to Williams (1996), H_2 pipelines will be similar to NG pipelines but will cost more, simply because higher pressures are required for H_2 transmission. Williams (1996) indicates that the cost per unit of pipeline will be 50% more and larger compressors will be needed. In this analysis, a cost of $1 million/mi was assumed for H_2 pipelines (Ogden et al. 1997). This cost is consistent with Williams' 50% cost increment vis a vis NG pipelines (using this study's separately derived cost estimate for NG pipeline).

The cost of converting a service station to dispense 50,000 GGE of H_2 was based on Williams (1996) and Berry et al. (1995). Neither reference specifically estimated the conversion cost for dispensing 50,000 GGE of H_2; thus, cost was interpolated from other H_2 dispensing volumes, assuming proportionality to volume throughput. The resulting conversion cost of $1.423 million/station assumed compression of H_2 to above 6000 psi for on-board vehicle storage.

3.2.8 Biodiesel

Pathway. Methyl soyate, produced from the transesterification of soy oil, was assumed to be produced in the United States, specifically in PADD II (the Midwest), and moved from production plants to bulk terminals by pipeline (63%), barge (8%), and rail (29%). Blending with conventional diesel oil, to an 80% diesel and 20% methyl soyate blend (or B20), was assumed to occur at bulk terminals, from which the fuel was assumed to be transported like conventional diesel (Figure 3.8). Mode splits were based on previous analysis of the movement of ethanol from the Midwest (PADD II) to the rest of the United States (EA Energy Technologies Group 1991).

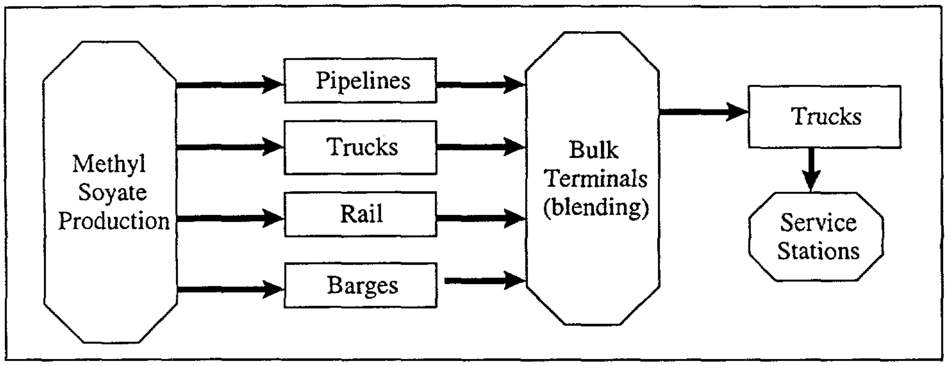


Figure 3.8 Biodiesel Distribution System

Equipment Requirements. For biodiesel, only the movement and storage of methyl soyate was assumed to require new equipment. Once methyl soyate is blended with diesel, the movement of biodiesel was assumed to use the same facilities as gasoline and diesel fuel. Because biodiesel has a higher energy content than the gasoline displaced in the PNGV analysis, no additional distribution capacity (including at service stations) should be required. Likewise, no significant changes in service station equipment should be required.

It was assumed that no additional pipeline or barge capacity would be required to move methyl soyate because there should be less of it moved than the gasoline displaced (methyl soyate has higher energy content than gasoline), and it comprises only 20% (by volume) of the biodiesel blend. Movement by rail was assumed to require new rail cars because gasoline is not currently moved by rail (diesel is moved by rail, but methyl soyate displaces gasoline, not diesel). At bulk terminals, no new storage capacity or truck tracks should be needed because idled gasoline facilities and equipment could be retrofit to store methyl soyate (prior to blending with diesel). Note that cross-contamination of products is less of a concern with biodiesel than with other fuels.

Cost. Distribution of methyl soyate incurs two principal costs: for new rail cars and for retrofitting storage tanks at bulk terminals. This analysis used the same costs for methyl soyate as were estimated for ethanol by the EA Energy Technologies Group (1991).

3.2.9 Reformulated Diesel and Fischer-Tropsch Diesel

The pathways, equipment requirements, and costs to distribute these fuels were assumed to be essentially the same as those for conventional gasoline and diesel fuel. Thus, no incremental capital requirements were assumed. Similarly, no incremental capital requirements were assumed for distributing RFG for 3X vehicles.

3.3 Assumptions and Methodologies Used to Calculate Unit Costs

Estimated unit or per-gallon costs for each fuel are presented in Section 3.4.3. This section presents the methodologies and assumptions used to derive those estimates. Per-gallon costs include capital costs (as estimated in this study), operating costs (including feedstock), and taxes. Capital costs reflect the incremental costs incurred to accommodate fuel demand by 3X vehicles. Converted to a per-gallon basis, these costs were computed as annual capital costs divided by annual fuel production. Operating cost estimates were derived from various sources, as explained below. Operating costs were already on a per-gallon basis. All costs for each fuel were converted to a gasoline-equivalent gallon for comparison purposes.

As one might expect, the way per-gallon costs were calculated in this study may not be the same as the way in which the fuels industry determines a fuel's price. Pricing of fuels is a sophisticated process affected by capital costs, investors' expectations for a return on their capital investments, expected short- and long-term profits, marketing strategies, fuel taxes, and so on. The cost estimation process used in this study was not intended by any means to predict potential prices of candidate 3X fuels. Instead, the intent was to put capital cost estimates for the different fuels into a common unit (a gasoline-gallon equivalent, or GGE) so readers can compare them with other estimates as well as with current prices. This comparison should put the individual estimates into perspective, both relative to one another and to the costs consumers already bear for existing fuels.

3.3.1 Fuel Production Costs

Fuel production costs (in \$/GGE) were calculated as the sum of per-gallon capital costs (annual capital cost divided by annual fuel production), feedstock operating costs, and non-feedstock operating costs. For biodiesel and corn-based ethanol, co-products account for a significant cost element. In these cases, the value of co-products was taken as a cost credit and deducted from the per-gallon cost of the fuel.

For the commodity fuels — gasoline, diesel, and CNG — per-gallon prices were estimated by using projected wellhead prices for crude oil and natural gas from the 1997 Annual Energy Outlook (EIA 1996a).

3.3.2 Transportation Costs of Liquid Fuels

Capital Costs of Distribution Equipment. As indicated above, the per-gallon capital cost for the transportation of a given liquid fuel was calculated as total annual capital cost divided by annual fuel use. As stated previously, capital cost was incremental to a reference case, which, in this portion of the analysis, included RFG-fueled 3X vehicles. For liquid fuels that were assumed to use existing gasoline distribution equipment (methanol and ethanol), the cost of converting that equipment was included in the capital cost calculation, but the cost of constructing the original (gasoline distribution) equipment was not. However, capitalization of the original gasoline equipment was included for methanol and ethanol per-gallon cost estimates.

Operating Costs of Ocean Tankers. A DOE report (DOE 1989) estimated the operating cost of a methanol tanker to range from well less than $0.01/gal to $0.04/gal (in 1989 dollars). This analysis assumed a cost of $0.025/gal (1995 dollars), which was applied to all liquid fuels moved by ocean tanker (i.e., methanol, LPG, and DME).

For alternative fuels, the cost attributable to ocean tanker operation is included under fuel distribution in the tables in Section 3.4.3. For gasoline and diesel fuel, this cost was assumed to be part of feedstock cost, because the cost of crude oil acquisition by refiners usually includes ocean transportation.

Operating Costs of Movement to Service Stations. The operating cost associated with moving any liquid fuel from marine terminal or domestic production center to service station was assumed to be similar to that for gasoline, on a volumetric basis. For gasoline, this cost was estimated to be $0.105/gal. This estimate is based on API and EIA data (API 1990; API 1996; EIA 1997b). Of that cost, $0.013/gal was estimated to be for capitalization of the equipment used to move gasoline from marine terminals or domestic production centers to the service stations. Thus, for all liquid fuels, the operating cost for movement from marine terminals or domestic production centers is $0.092/gal. For those liquid fuels that make use of the existing gasoline (or diesel fuel) distribution system, $0.013/gal in capital costs must be added to the above-estimated capital costs. Table 3.7 summarizes these assumptions.

Table 3.7 Per-Gallon Cost of Transporting Liquid Fuels from Marine Terminals or Domestic Production Centers to Service Stations (1995 ¢/physical gal)

Fuel	Capital Cost of Gasoline System (¢/gal)	Incremental Capital Cost of Alternative Fuel Systems (¢/gal)	Operating Cost of All Systems (¢/gal)
Gasoline	1.3	NA	9.2
Methanol	1.3	Varies by year	9.2
Ethanol	1.3	Varies by year	9.2
LPG	NA	Varies by year	9.2
DME	NA	Varies by year	9.2
LNG	NA	Varies by year	9.2
B20	1.3	Varies by year	9.2

NA = Not applicable.

3.3.3 Transportation Costs of Gaseous Fuels

CNG. The cost of moving natural gas from NG processing plants to service stations depends to a significant extent on whether that movement is via an existing or a new distribution system. Using EIA's projections of vehicular natural gas use (0.31 TCF by 2015) as a threshold, CNG demand by 3X vehicles was categorized as either less than or greater than existing system capacity. For demand levels less than or equal to 0.31 TCF, EIA's estimates of the transportation and distribution (T&D) margins for natural gas pipelines were used directly. Those projections can be found in EIA's AEO 1997 (EIA 1996a). For demand levels above 0.31 TCF, transportation costs must also include the capital costs of building new pipelines (see Section 3.2.6), as well as operating costs associated with all distribution facilities and equipment. For this analysis, the capitalization component of new pipeline operating costs was estimated by using historical data on natural gas transportation and distribution (T&D) margins (EIA 1995). Thus, for vehicular CNG use above 0.31 TCF, estimated capital costs were combined with 77% of EIA's natural gas T&D margins to yield total NG transportation costs.

Hydrogen. Because all hydrogen pipelines were assumed to be new, the process used to estimate capital costs was straightforward and uncertainties were kept to a minimum (see Section 3.2.7). Not so for operating costs. Given the greater compression requirements of hydrogen pipelines, operating costs should be greater than those for natural gas pipelines. However, there are no reliable estimates of those costs. For this analysis, the operating costs estimated for new NG pipelines (i.e., EIA's T&D margins less capitalization costs) were used for hydrogen pipelines as well.

3.3.4 Service Station Costs

A gasoline markup of \$0.087/gal, reflecting the capital and operating costs of service stations, was calculated from the API and EIA data referenced above. For alternative fuels, capitalization costs for station conversion were added to this figure. All station conversion costs were assigned to alternative fuels (i.e., costs were not spread over the gasoline dispensed at the station).

No incremental operating costs were assumed for any liquid fuel. This assumption is consistent with the findings of prior analyses of methanol, ethanol, LPG (and thus, by extension, DME), and LNG (EEA 1995; Acurex Environmental Corporation 1992).

For CNG, incremental O&M costs of \$0.116/GGE were assumed (EEA 1995). For H_2, incremental O&M costs are expected to be somewhat higher than \$0.116/GGE because H_2 compressors operate at higher pressure than CNG compressors. This was not confirmed by the literature, however. Williams projected O&M costs of approximately \$0.06/GGE (1996), nearly half EEA's estimate for CNG. It is not clear why the two studies differ so markedly. Nevertheless, given the great uncertainty in H_2 estimates in general, this analysis assumed the same incremental service station O&M costs for H_2 as for CNG.

3.3.5 Taxes

According to the American Petroleum Institute, total U.S. gasoline taxes average \$0.424/gal (API 1996). Total taxes include federal, state, and local taxes. Federal diesel taxes are \$0.184/gal, and the median value of state diesel taxes is \$0.19/gal (Davis 1997). On a GGE basis, these taxes equate to \$0.391/gal. With the exception of diesel-like fuels, all fuels considered in this analysis were assumed to be taxed like gasoline,[13] and all diesel-like fuels were assumed to be taxed like diesel. All taxes are on a per-Btu basis.

3.4 Capital Requirements

Annual and cumulative capital costs of fuel production and distribution infrastructure and per-gallon costs are presented below. Capital requirements were annualized by using a 10-yr payback and a 10% real-term interest rate. For NG and H_2 pipelines, a 50-yr payback was assumed to better reflect the life expectancy of pipelines as compared with other components of fuel distribution systems.

3.4.1 Facility and System Requirements

Fuel Production Facilities. Table 3.8 summarizes the main components of the physical production systems required to meet the fuel demands of 3X vehicles. Entries are the cumulative numbers of plants/facilities and expected production capacities of each fuel through 2030. On a Btu basis, production capacities are equivalent for all except the two blended fuels — B20 and F-T50 — for which production need cover only the blended fraction.

Fuel Distribution Equipment. Tables 3.9 and 3.10 provide cumulative estimates of the equipment required to distribute the various liquid and gaseous fuels through 2030. Except for trucks, values shown are also estimates of the total equipment required to distribute the various fuels in that year. Annual estimates of equipment requirements were developed, but they are not presented here.

3.4.2 Total Capital Costs

Fuel Production. Table 3.11 presents estimates of the annual cost of phasing in the production facilities described in Table 3.8. Figure 3.9 presents the same data graphically. As shown in the figure, hydrogen is by far the most expensive of the fuels considered, followed by DME and ethanol. At the other end of the spectrum, Fischer-Tropsch diesel, B20, and LPG are the least expensive. In the case of B20, the low percentage of methyl soyate in the biodiesel blend greatly reduces incremental capital costs. As has been noted, all costs are incremental to an RFG-fueled reference case. Thus, 80% of the blended B20 fuel adds no capital cost.

Table 3.12 presents estimates of incremental capital requirements for building fuel production facilities cumulatively through 2015, 2020, 2025, and 2030. Again, hydrogen, DME, and ethanol are the most costly of the alternatives examined, while B20, F-T50, and LPG are the least costly.

[13] Ethanol tax incentives (currently equivalent to \$0.51/gal in federal tax exceptions) are not included.

Table 3.8 Production Facilities and Capacity Required to Supply Demand for 3X Fuel in 2030

	High-Market-Share Scenario		Low-Market-Share Scenario	
Fuel	Capacity	Facilities	Capacity	Facilities
M100	45.1 $\times 10^9$ gal/yr	40 plants @ 10K MTPD 5 Plants @ 2500 MTPD	13.4 $\times 10^9$ gal/yr	11 plants @ 10K MTPD 5 Plants @ 2500 MTPD
E100	32.4 $\times 10^9$ gal/yr	1,168 cellulosic plants 21 wet mill plants 5 dry mill plants	10.1 $\times 10^9$ gal/yr	374 cellulosic plants 4 wet-mill plants No dry-mill plants
LPG	30.0 $\times 10^9$ gal/yr	280 domestic projects 40 foreign projects	9.3 $\times 10^9$ gal/yr	117 domestic projects 6 foreign projects
DME	37.6 $\times 10^9$ gal/yr	65 plants	11.6 $\times 10^9$ gal/yr	20 plants
LNG[a]	33.8 $\times 10^9$ gal/yr	1,377 plants	10.5 $\times 10^9$ gal/yr	428 plants
CNG[b]	2.7 tcf/yr	25,385 wells	0.7 tcf/yr	7,878 wells
H_2	8.4 tcf/yr	59 NG plants @1.7 $\times 10^8$ scf/d H_2; 155 solar plants @ 1 $\times 10^8$ scf/d H_2	2.6 tcf/yr	11 NG plants @1.7 $\times 10^8$ scf/d H_2; 60 solar plants @ 1 $\times 10^8$ scf/d H_2
B20	4.1 $\times 10^9$ gal/yr (methyl soyate)	1,359 plants	1.3 $\times 10^9$ gal/yr (methyl soyate)	423 plants
F-T50	10.6 $\times 10^9$ gal/yr (FTD)	1 plant @ 0.7 $\times 10^9$ gal/yr 7 plants @ 1.4 $\times 10^9$ gal/yr	2.9 $\times 10^9$ gal/yr (FTD)	2 plants @ 0.7 $\times 10^9$ gal/yr 1 plant @ 1.4 $\times 10^9$ gal/yr

[a] Requires additional NG processing plants, the costs of which are included in Section 3.4 estimates.
[b] Requires additional NG wells (see CNG), the costs of which are included in Section 3.4 estimates.

Fuel Distribution. Figure 3.10 presents annual capital costs for developing the infrastructure to distribute fuels under the high- and low-market-share scenarios. Table 3.13 presents those costs cumulatively through the years 2015, 2020, 2025, and 2030 for both scenarios.

The cumulative cost of building the infrastructure for biodiesel is insignificant relative to the other fuels: $32 million vs. $8 billion for ethanol, the next least expensive alternative under the high scenario. Infrastructure costs for liquid fuels (ranging from $8 to $30 billion under the high scenario) are significantly less than those for gaseous fuels (ranging from $144 to $268 billion under that scenario). This relationship holds in all years of both scenarios and remains true even when the payback period for natural gas and hydrogen pipelines is raised from 10 to 50 years. With a 50-yr payback, capital costs for CNG and H_2 distribution systems drop (to $103 and $187 billion, respectively, under the high scenario), but they are still far higher than those for liquid fuels. The same pattern occurs under the low scenario.

Total Costs. For most of the fuels considered in this analysis, production costs far exceed distribution costs (see Tables 3.12 and 3.13). This phenomenon is particularly true for B20 (where production costs are approximately two orders of magnitude higher

Table 3.9 Distribution Facilities Required to Supply Liquid Fuel Demand of 3X Vehicles in 2030[a]

	Ocean Tankers	Terminal Tankage (10^6 bbl)	Truck Racks	Trucks[b]	Pipelines (mi)	Rail Cars	Barges	Service Stations
Low-Market-Share Scenario								
M100	86	18.4	52	1,410	0	0	0	11,360
E100	0	13.8	46	1,338	846	907	24	11,360
LPG	11	12.4	41	1,290	846	0	10	11,360
DME	74	15.8	52	1,214	0	0	0	11,360
LNG	0	10.4	35	2,042	0	117	0	11,360
B20	0	1.6	0	0	0	67	0	0
High-Market-Share Scenario								
M100	275	77.1	176	4,653	2,188	0	0	36,572
E100	0	44.3	148	3,781	2,707	2,920	76	36,572
LPG	72	40.0	121	3,441	1,993	159	24	36,572
DME	237	66.3	168	4,006	1,914	0	0	36,572
LNG	0	33.6	113	6,189	0	1,063	0	36,572
B20	0	5.1	0	0	0	215	0	0

[a] Physical number of new or converted facilities or equipment.
[b] Including replacements.

Table 3.10 Distribution Facilities Required to Supply Gaseous Fuel Demand of 3X Vehicles in 2030[a]

	Pipelines (mi)	Service Stations
Low-Market-Share Scenario		
CNG	39,247	11,360
H_2	62,807	11,360
High-Market-Share Scenario		
CNG	178,631	36,572
H_2	202,191	36,572

[a] Physical number of new or converted facilities or equipment.

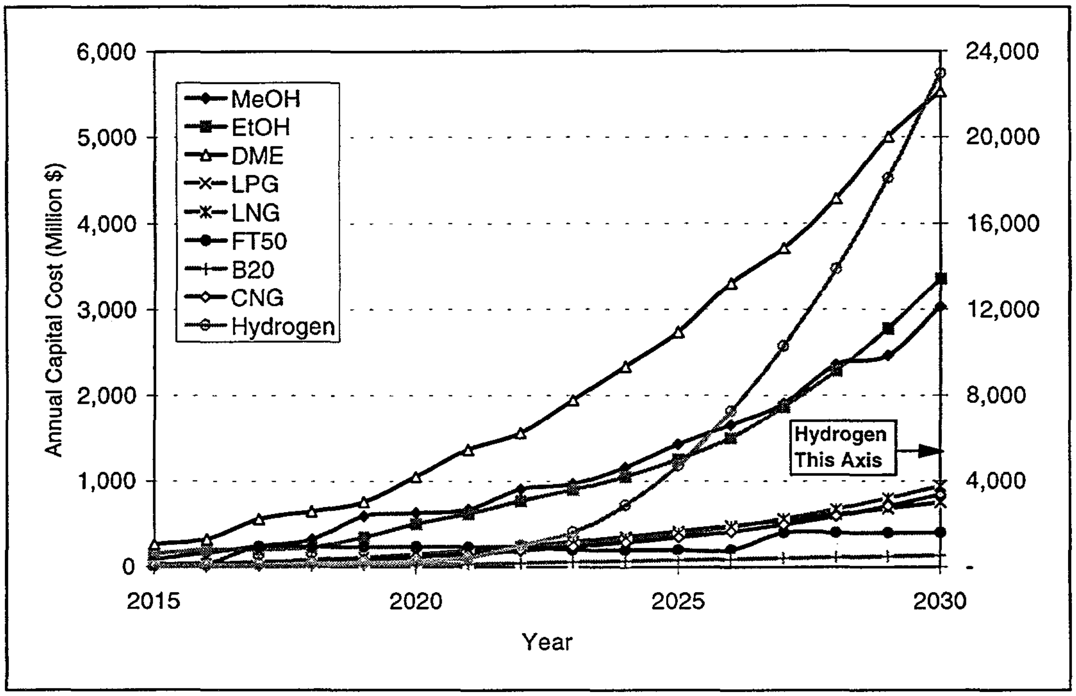
than distribution costs), E100, DME and M100. For LPG, which requires additional pipeline capacity, production costs only slightly exceed distribution costs. The same holds true for hydrogen, but both costs far exceed those of any other alternative examined. CNG (for which additional pipelines account for much of the incremental cost) is the sole exception to this pattern.

3.4.3 Unit Costs

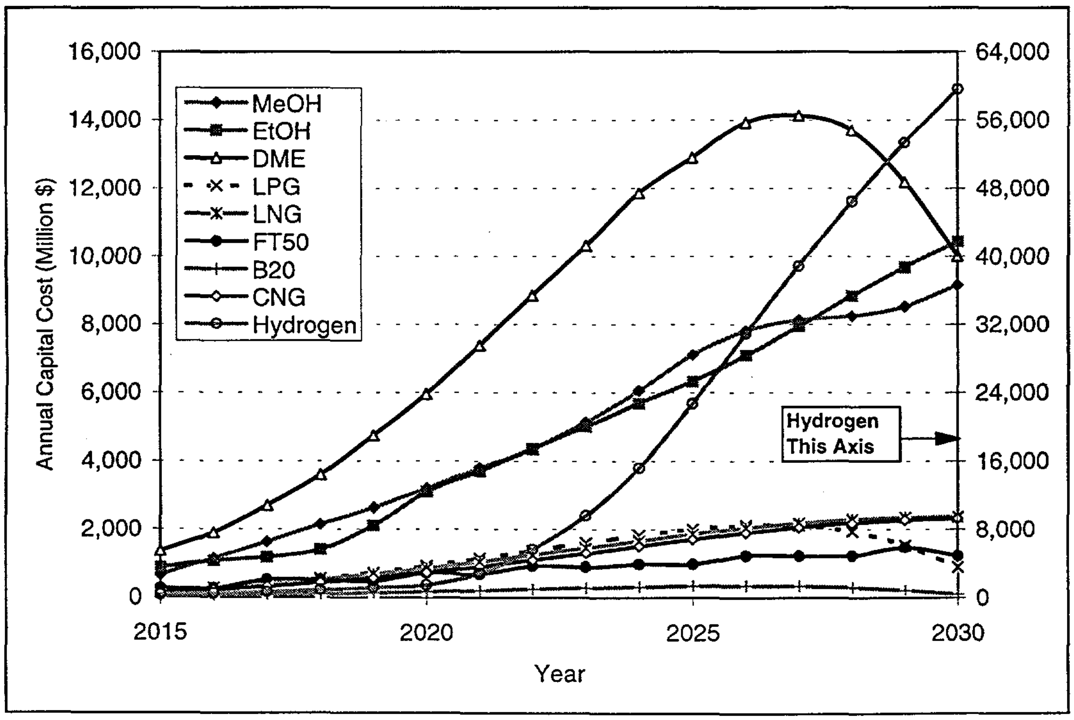
Figure 3.11 illustrates the unit cost (in GGEs) of each fuel over time for both scenarios. As noted above, these costs are based on estimated capital costs, not prices. No attempt has been made to predict pump

Table 3.11 Annual Capital Cost of Building Fuel Production Facilities by Year and Fuel Type ($ million)

	Methanol		Ethanol		Hydrogen		CNG		DME		F-T50		B20		LNG		LPG	
	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
2007	0.8		0.0		0.2		0.7		3.0		0.0		0.5		0.7		0.8	
2008	3.0		13.6		0.9		2.5		174.7		0.0		1.1		4.3		3.1	
2009	67.7		40.8		2.1		6.2		192.3		40.7		1.6		9.6		7.6	
2010	75.0		68.0		37.6		12.1		221.4		40.7		3.2		17.3		15.0	
2011	86.4		118.3		40.8		21.3		266.2		81.4		5.4		28.2		26.5	
2012	164.1		218.9		79.2		35.6		335.5		81.4		8.6		46.0		44.3	
2013	251.6	3.9	369.9	50.3	120.3	1.1	57.7	3.3	605.9	15.5	122.1	40.7	14.0	1.1	75.1	6.7	71.9	4.0
2014	414.4	72.6	571.1	100.6	199.1	36.9	92.2	10.2	773.5	211.8	275.9	40.7	22.0	2.7	120.0	15.4	115.0	12.6
2015	665.6	85.3	872.9	150.9	284.4	40.5	145.3	20.4	1,357.7	262.1	275.9	40.7	34.9	5.4	187.0	29.1	181.6	25.5
2016	1,131.3	160.9	1,074.1	201.2	444.7	78.3	221.9	32.9	1,892.9	322.7	275.9	40.7	53.2	8.1	280.9	41.6	277.4	41.1
2017	1,624.7	239.6	1,174.7	201.2	646.3	116.9	320.2	48.0	2,697.1	558.8	520.0	235.2	76.3	11.8	396.6	60.2	401.7	60.0
2018	2,144.4	322.4	1,401.7	225.3	888.7	156.7	438.9	66.3	3,596.7	647.8	520.0	235.2	103.7	16.1	530.9	80.2	552.7	82.8
2019	2,629.1	595.7	2,108.4	345.6	1,171.6	197.8	576.2	88.6	4,740.8	755.8	479.3	235.2	135.3	21.5	683.9	105.9	727.3	110.6
2020	3,197.7	628.8	3,091.7	502.0	1,461.2	240.6	730.4	115.4	5,949.6	1,049.6	723.4	235.2	170.2	27.9	850.3	136.2	922.0	144.3
2021	3,794.1	669.0	3,703.0	622.3	2,842.1	435.2	904.0	148.1	7,386.3	1,371.3	682.7	235.2	208.4	35.4	1,039.5	174.1	1,138.3	185.1
2022	4,356.2	903.4	4,348.3	766.6	5,618.2	995.3	1,093.6	187.6	8,856.3	1,563.6	926.8	235.2	248.7	45.1	1,241.2	218.9	1,369.2	234.5
2023	5,128.0	962.2	5,003.4	896.8	9,605.1	1,613.1	1,294.8	232.1	10,313.2	1,943.3	886.1	194.5	287.9	55.3	1,451.1	265.1	1,603.9	290.3
2024	6,047.3	1,158.5	5,680.4	1,051.0	15,206.0	2,864.5	1,501.4	282.8	11,851.6	2,236.9	976.5	194.5	322.8	66.1	1,661.2	322.8	1,826.0	350.4
2025	7,106.6	1,429.3	6,316.9	1,253.3	22,673.2	4,709.3	1,705.4	341.6	12,883.7	2,736.6	976.5	194.5	349.1	77.3	1,865.1	386.8	2,010.9	412.8
2026	7,807.2	1,656.5	7,090.1	1,503.8	30,878.4	7,257.9	1,896.3	411.8	13,919.3	3,304.1	1,220.6	194.5	359.8	88.6	2,045.6	467.4	2,122.7	477.6
2027	8,130.2	1,903.0	7,939.9	1,864.7	38,885.3	10,290.7	2,059.7	495.0	14,126.8	3,711.7	1,220.6	397.9	345.9	100.4	2,186.5	559.3	2,110.6	544.5
2028	8,249.4	2,357.2	8,842.2	2,285.7	46,399.8	13,879.1	2,187.1	592.9	13,688.8	4,279.7	1,220.6	397.9	301.3	111.7	2,287.8	669.3	1,932.0	612.9
2029	8,531.5	2,464.3	9,684.3	2,779.0	53,301.1	18,088.5	2,275.5	706.6	12,179.2	4,999.3	1,464.7	397.9	220.2	123.0	2,343.2	795.2	1,521.4	681.4
2030	9,161.2	3,030.0	10,442.2	3,356.4	59,562.1	22,977.8	2,325.1	837.6	10,017.1	5,531.1	1,220.6	397.9	99.9	132.7	2,363.3	940.1	889.2	747.4



(a) Low-Market-Share Scenario



(b) High-Market-Share Scenario

Figure 3.9 Annual Costs for Building Fuel-Production Facilities

Table 3.12 Incremental Capital Requirements for Building Fuel Production Facilities, Cumulative through 2015, 2020, 2025, and 2030 ($ billion)

Fuel	2015	2020	2025	2030
Low-Market-Share Scenario				
M100	0.2	2.1	7.2	18.6
E100	0.3	1.8	6.4	18.2
LPG	0.04	0.5	2.0	5.0
DME	0.5	3.8	13.8	35.6
LNG	0.1	0.5	1.8	5.3
CNG	0.03	0.4	1.6	4.6
H_2	0.1	0.9	11.5	84.0
B20	0.01	0.1	0.4	0.9
F-T50	0.1	1.1	2.2	3.9
High-Market-Share Scenario				
M100	1.7	12.5	38.9	80.8
E100	2.3	11.1	36.2	80.2
LPG	0.5	3.3	11.3	19.9
DME	3.9	22.8	74.1	138.0
LNG	0.5	3.2	10.5	21.7
CNG	0.4	2.7	9.2	19.9
H_2	0.8	5.4	61.3	290.3
B20	0.1	0.6	2.0	3.4
F-T50	0.9	3.4	7.9	14.2

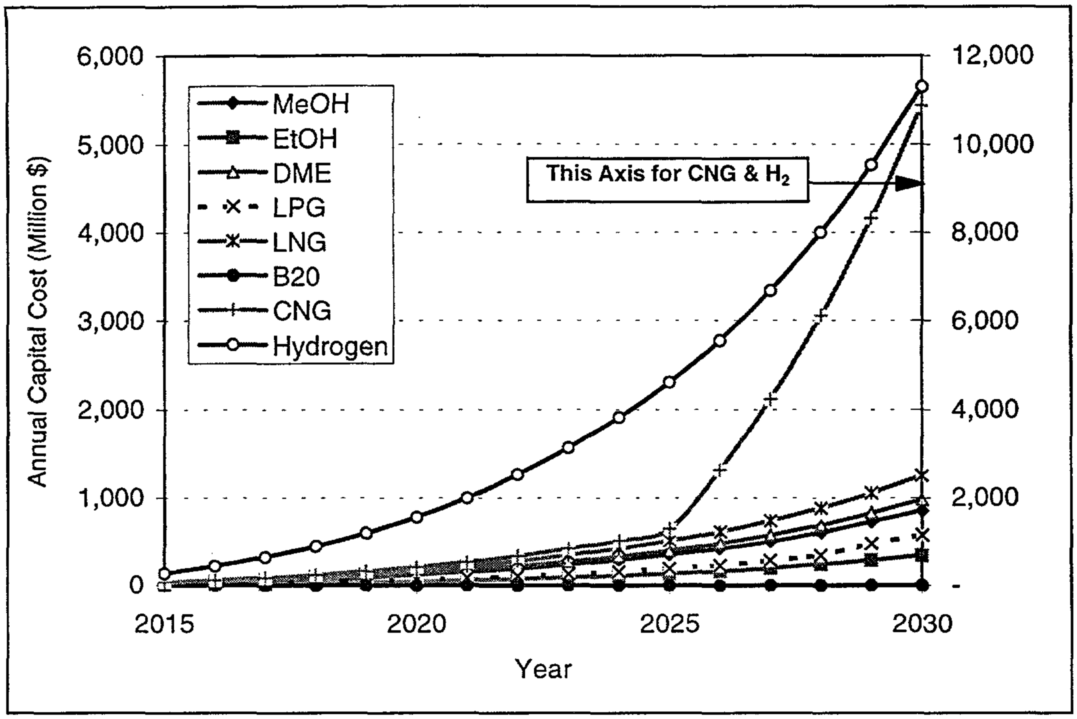
Table 3.13 Incremental Capital Requirements for Building Fuel Distribution Facilities, Cumulative through 2015, 2020, 2025, and 2030 ($ billion)

Fuel	2015	2020	2025	2030
Low-Market-Share Scenario				
M100	0.0	0.4	1.6	4.7
E100	0.0	0.2	0.6	1.8
LPG	0.0	0.3	0.9	2.8
DME	0.0	0.5	1.9	5.4
LNG	0.1	0.6	2.3	6.9
CNG: 10 yr	0.1	0.7	2.9	19.0
CNG: 50 yr	0.1	0.7	2.9	14.9
H_2: 10 yr	0.5	5.2	21.3	62.3
H_2: 50 yr	0.3	3.6	14.8	43.5
B20	0.00	0.00	0.00	0.01
F-T50	0.00	0.00	0.00	0.00
High-Market-Share Scenario				
M100	0.4	2.7	9.3	20.6
E100	0.1	1.1	3.7	8.1
LPG	0.3	1.6	6.1	14.1
DME	0.5	3.1	10.7	23.8
LNG	0.6	4.0	13.6	29.7
CNG: 10 yr	0.7	9.4	54.5	143.6
CNG: 50 yr	0.7	7.6	40.0	102.6
H_2: 10 yr	5.0	35.9	123.5	268.4
H_2: 50 yr	3.5	25.0	86.2	187.3
B20	0.00	0.00	0.01	0.03
F-T50	0.00	0.00	0.00	0.00

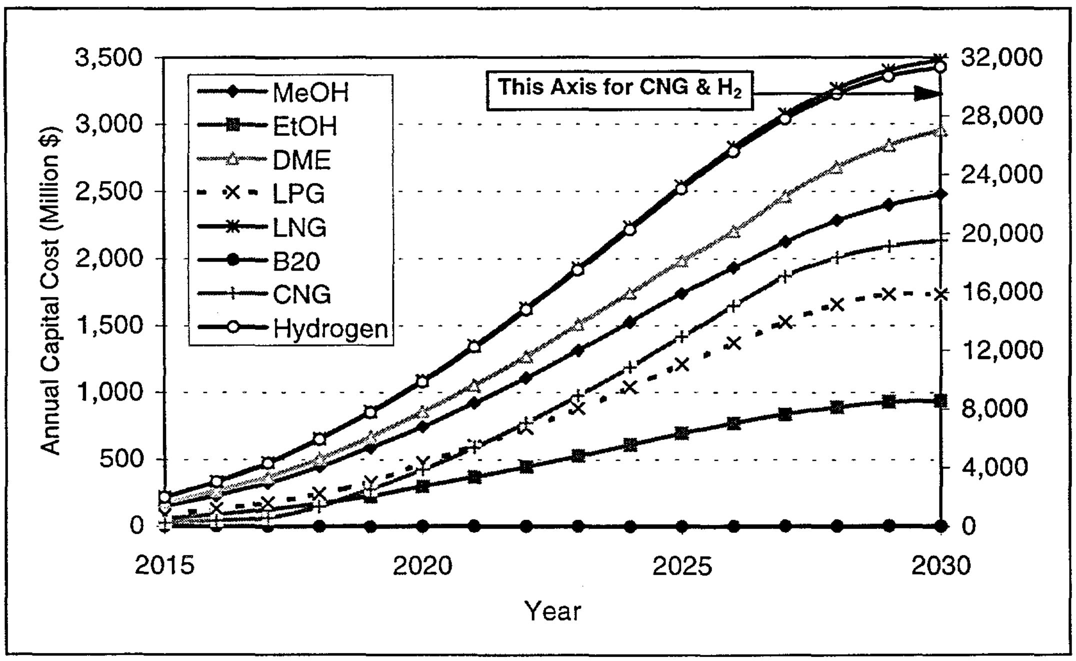
prices. As shown in the figure, unit costs of DME, ethanol, LPG, and, to a certain extent, methanol are quite high in the first year relative to later years. This is one area where the cost of the fuel and the price producers are likely to charge for it may be expected to differ dramatically. High initial costs reflect the need to construct facilities or purchase equipment with capacities far in excess of projected demand volumes for that initial year. As demand increases, economies of scale permit unit costs to decline. This decline does not occur for so-called volume fuels like RFD, RFG, natural gas, and B20,[14,15] which were assumed to be produced in large-scale plants from the outset and thus had already achieved economies of scale by 2007.

[14] Because of economies of scale, LPG cost declines by nearly 50% between 2007 and 2010. This decline is not readily apparent in Figure 3.11b because of the wide range of costs shown.

[15] Because methyl soyate comprises only 20% of the blended B20 fuel, unit cost more closely resembles that of RFD, the 80% component.

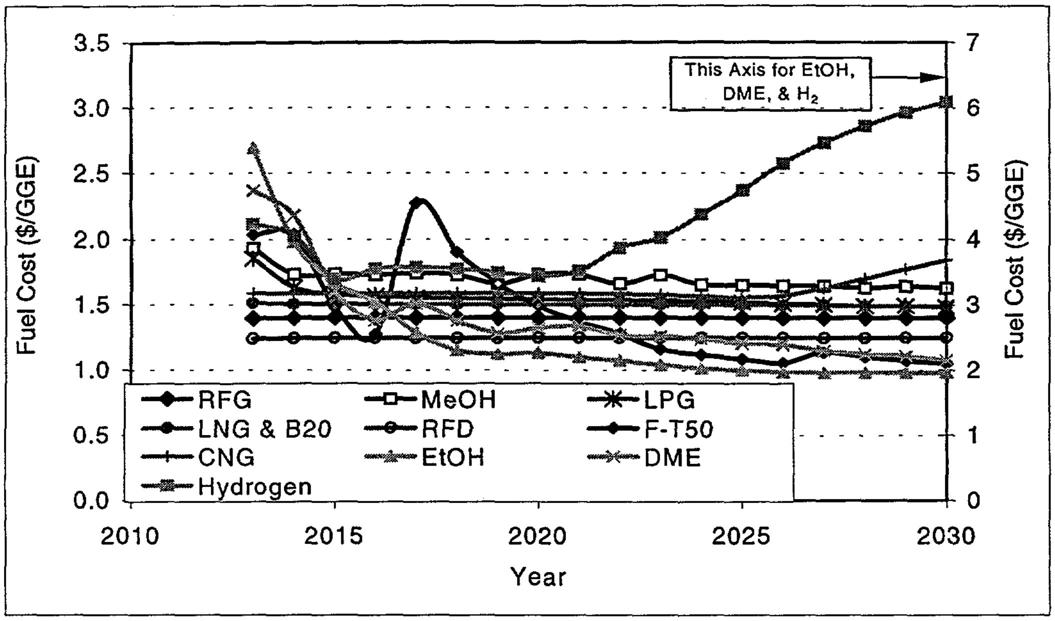


(a) Low-Market-Share Scenario

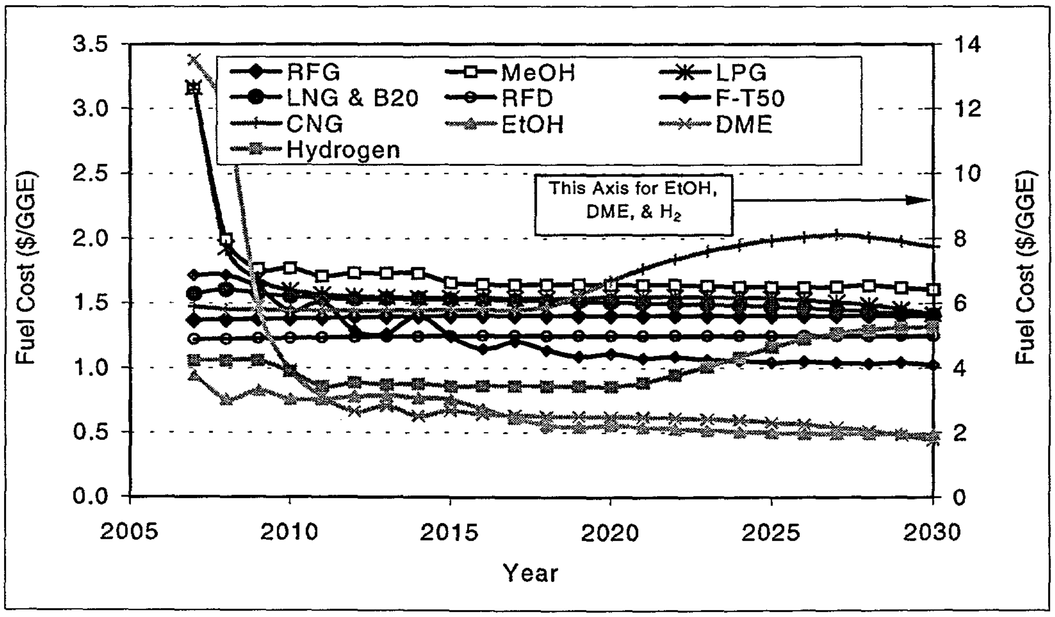


(b) High-Market-Share Scenario

Figure 3.10 Annual Costs for Building Fuel-Distribution Facilities



(a) Low-Market-Share Scenario



(b) High-Market-Share Scenario

Figure 3.11 Unit Costs of Potential 3X Fuels (1995$/GGE)

Hydrogen, which was assumed to be produced in relatively small-scale decentralized facilities (centralized production of hydrogen will be examined in phase 3 of this analysis), never achieves economies of scale. Although scale economies are achieved for CNG production, the need to expand distribution capacity by building new pipelines greatly increases unit costs in the latter years of the analysis.

Similar relationships exist for the low-market-share scenario. However, all of the alternative fuels are more expensive than under the high-market-share scenario. This difference demonstrates the importance of generating sufficient demand for new transportation fuels in order to achieve economies of scale. Again, CNG is an exception in the latter years of the analysis, primarily because of the need for expensive pipeline additions.

Of the 11 fuels examined in this study, the blended Fischer-Tropsch diesel (F-T50) exhibits the most distinctive cost curve, undoubtedly a result of assumptions about facility sizes. As discussed above, FTD was assumed to be produced in three different-sized plants. The smallest, essentially a prototype facility with 5,000-BPD rated capacity, equates to double that capacity (or 130 million GGE per year) when blended with conventional diesel. In the first few years of production at this scale, the capital component of per-gallon cost initially declines because of growth in fuel demand and fairly constant annual capital cost. When the first 50,000 BPD facility (1.3 billion GGE per year blended fuel) comes on-line, per-gallon cost jumps because year-to-year demand increases by approximately 60%, while capital costs of production increase by a factor of five. Unit cost declines in subsequent years as, again, demand grows, while annual capital cost remains constant.

Tables 3.14 and 3.15 disaggregate the unit cost components of the fuels for the years 2015, 2020, 2025, and 2030. Note that changing the payback period for natural gas and hydrogen pipelines has a significant effect on the cost of these two fuels. Under the high-market-share scenario, CNG is about \$0.15/GGE cheaper and H_2 is about \$0.40/GGE cheaper with a 50-yr, as opposed to a 10-yr, payback period.

Table 3.14 Unit Costs of Potential 3X Vehicle Fuels by Component: Low-Market-Share Scenario (1995$/GGE)

	Production Costs					
Fuel	Feedstock	Fuel Production	Distribution	Service Station	Taxes	Total
2015						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.592	0.368	0.137	0.424	1.735
E100	1.678	0.935	0.170	0.133	0.424	3.339
LPG	0.600	0.219	0.196	0.142	0.424	1.582
DME	0.324	1.977	0.318	0.158	0.424	3.202
LNG	0.343	0.345	0.188	0.250	0.424	1.549
CNG: 10 yr	0.258	0.280	0.170	0.455	0.424	1.587
CNG: 50 yr	0.258	0.280	0.170	0.455	0.424	1.587
H_2: 10 yr	0.380	0.370	1.630	0.589	0.424	3.394
H_2: 50 yr	0.380	0.370	1.060	0.589	0.424	2.823
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.153	0.096	0.087	0.391	1.505
F-T50	0.362	0.630	0.010	0.087	0.391	1.480
2020						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.592	0.364	0.136	0.424	1.731
E100	0.792	0.745	0.169	0.133	0.424	2.263
LPG	0.600	0.219	0.156	0.142	0.424	1.542
DME	0.324	1.436	0.298	0.158	0.424	2.641
LNG	0.343	0.310	0.188	0.250	0.424	1.514
CNG: 10 yr	0.258	0.277	0.170	0.455	0.424	1.584
CNG: 50 yr	0.258	0.277	0.170	0.455	0.424	1.584
H_2: 10 yr	0.380	0.409	1.630	0.589	0.424	3.433
H_2: 50 yr	0.380	0.409	1.060	0.589	0.424	2.863
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.150	0.096	0.087	0.391	1.502
F-T50	0.362	0.640	0.010	0.087	0.391	1.490
2025						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.523	0.354	0.134	0.424	1.649
E100	0.547	0.721	0.168	0.131	0.424	1.991
LPG	0.600	0.204	0.152	0.139	0.424	1.519
DME	0.324	1.214	0.291	0.154	0.424	2.407
LNG	0.343	0.294	0.185	0.241	0.424	1.486
CNG: 10 yr	0.258	0.261	0.170	0.441	0.424	1.553
CNG: 50 yr	0.258	0.261	0.170	0.441	0.424	1.553
H_2: 10 yr	0.298	1.906	1.546	0.567	0.424	4.741
H_2: 50 yr	0.298	1.906	1.008	0.567	0.424	4.203
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.146	0.096	0.087	0.391	1.498
F-T50	0.362	0.232	0.010	0.087	0.391	1.082

Continued

Table 3.14 Unit Costs of Potential 3X Vehicle Fuels by Component: Low-Market-Share Scenario (1995$/GGE) (Cont.)

	Production Costs					
Fuel	Feedstock	Fuel Production	Distribution	Service Station	Taxes	Total
2030						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.510	0.347	0.130	0.424	1.625
E100	0.476	0.760	0.170	0.128	0.424	1.957
LPG	0.599	0.155	0.168	0.136	0.424	1.482
DME	0.324	0.961	0.287	0.149	0.424	2.145
LNG	0.343	0.283	0.182	0.230	0.424	1.462
CNG: 10 yr	0.258	0.229	0.506	0.424	0.424	1.841
CNG: 50 yr	0.258	0.229	0.369	0.424	0.424	1.704
H_2: 10 yr	0.153	3.523	1.449	0.542	0.424	6.091
H_2: 50 yr	0.153	3.523	0.948	0.542	0.424	5.590
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.136	0.096	0.087	0.391	1.488
F-T50	0.362	0.199	0.010	0.087	0.391	1.049

Table 3.15 Unit Costs of Potential 3X Vehicle Fuels by Component: High-Market-Share Scenario (1995$/GGE)

	Production Costs					
Fuel	Feedstock	Fuel Production	Distribution	Service Station	Taxes	Total
2015						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.523	0.358	0.136	0.424	1.656
E100	1.671	0.628	0.169	0.133	0.424	3.025
LPG	0.600	0.219	0.154	0.142	0.424	1.540
DME	0.324	1.473	0.303	0.158	0.424	2.681
LNG	0.343	0.325	0.188	0.250	0.424	1.529
CNG: 10 yr	0.258	0.140	0.170	0.455	0.424	1.447
CNG: 50 yr	0.258	0.140	0.170	0.455	0.424	1.447
H_2: 10 yr	0.380	0.408	1.630	0.589	0.424	3.432
H_2: 50 yr	0.380	0.408	1.060	0.589	0.424	2.862
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.150	0.096	0.087	0.391	1.502
F-T50	0.385	0.370	0.010	0.087	0.391	1.243
2020						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.510	0.356	0.136	0.424	1.640
E100	0.764	0.730	0.171	0.132	0.424	2.222
LPG	0.599	0.219	0.167	0.142	0.424	1.551
DME	0.324	1.280	0.297	0.157	0.424	2.481
LNG	0.343	0.305	0.187	0.247	0.424	1.506
CNG: 10 yr	0.258	0.138	0.398	0.451	0.424	1.668
CNG: 50 yr	0.258	0.138	0.303	0.451	0.424	1.574
H_2: 10 yr	0.380	0.424	1.606	0.583	0.424	3.417
H_2: 50 yr	0.380	0.424	1.045	0.583	0.424	2.856
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.149	0.096	0.087	0.391	1.500
F-T50	0.385	0.234	0.010	0.087	0.391	1.108
2025						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.499	0.351	0.133	0.424	1.620
E100	0.565	0.706	0.170	0.130	0.424	1.995
LPG	0.597	0.199	0.177	0.138	0.424	1.535
DME	0.324	1.128	0.290	0.152	0.424	2.318
LNG	0.343	0.286	0.184	0.237	0.424	1.474
CNG: 10 yr	0.258	0.129	0.739	0.435	0.424	1.985
CNG: 50 yr	0.258	0.129	0.511	0.435	0.424	1.757
H_2: 10 yr	0.295	1.850	1.513	0.559	0.424	4.641
H_2: 50 yr	0.295	1.850	0.987	0.559	0.424	4.115
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.143	0.096	0.087	0.391	1.495
F-T50	0.385	0.169	0.010	0.087	0.391	1.042

Continued

Table 3.15 Unit Costs of Potential 3X Vehicle Fuels by Component: High-Market-Share Scenario (1995$/GGE) (Cont.)

	Production Costs					
Fuel	Feedstock	Fuel Production	Distribution	Service Station	Taxes	Total
2030						
RFG	0.540	0.241	0.108	0.087	0.424	1.400
M100	0.214	0.501	0.341	0.124	0.424	1.604
E100	0.512	0.727	0.168	0.122	0.424	1.953
LPG	0.596	0.089	0.177	0.129	0.424	1.414
DME	0.324	0.593	0.287	0.141	0.424	1.769
LNG	0.343	0.253	0.178	0.210	0.424	1.407
CNG: 10 yr	0.258	0.106	0.753	0.394	0.424	1.935
CNG: 50 yr	0.258	0.106	0.518	0.394	0.424	1.700
H_2: 10 yr	0.174	2.906	1.268	0.496	0.424	5.267
H_2: 50 yr	0.174	2.906	0.835	0.496	0.424	4.835
RFD	0.504	0.170	0.095	0.087	0.391	1.246
B20	0.778	0.121	0.096	0.087	0.391	1.473
F-T50	0.385	0.150	0.010	0.087	0.391	1.023