JACKFAU-86-322-8/11

METHANOL PRICES DURING TRANSITION

FINAL REPORT

Submitted to:

U.S. ENVIRONMENTAL PROTECTION AGENCY
2565 Plymouth Road
Ann Arbor, Michigan 48105

August, 1987

JACK FAUCETT ASSOCIATES

7300 PEARL STREET • SUITE 200

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ACKNOWLEDGEMENTS

This report was prepared by Jack Faucett Associates (JFA) for the U.S. Environmental Protection Agency (EPA). The U.S. Department of Energy, the California Energy Commission and Jack Faucett Associates also contributed funding. The project was directed by Michael F. Lawrence and the report was researched and written by Linda Lent and Jon Skolnik of JFA. Don Hutson produced the document.

We wish to thank a wide range of individuals and companies throughout the country who cooperated with the research effort. While too numerous to identify individually, the list includes methanol producers, methanol researchers, policy makers desirous to promote methanol as a transportation fuel (and a few who do not see a future for methanol), and the shipping industry. Special appreciation is extended to Michael Gold and Jeff Alson of the Environmental Protection Agency, Lilly Ghaffari of the California Energy Commission, and Barry McNutt of the Department of Energy.

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CHAPTER 1:

INTRODUCTION AND SUMMARY

In recognition of the environmental benefits of the use of methanol as an alternative transportation fuel, the U.S. Environmental Protection Agency's Office of Mobile Sources conducts on-going research on the use of methanol in transportation applications. In support of EPA's efforts, Jack Faucett Associates, Inc. prepared this report to provide an analytical tool for policy makers concerned with methanol as a transportation fuel.

Consumer confidence in methanol as a transportation fuel will be developed during the early years of methanol use. During this period consumer confidence, so critical to the eventual success of methanol, may suffer significant damage if fuel prices are unstable and unpredictable. Thus, it is important for public policy analysts concerned with the transition to an alternative transportation fuel to understand how the market price of methanol will change as the current conditions of excess production capacity abate and new, fully-costed capital is brought into use.

Future prices of transportation fuels are uncertain. The prices will be affected by market demand, production costs and international trade agreements, as well as war, blockades, embargos, cartels, and other unpredictable acts of nations and producers. In spite of these uncertainties, it is incumbent upon public policy analysts to develop assumptions about pricing trends if sound public policy is to be developed. Most analysts agree that gasoline will some day be replaced as our principal transportation fuel. Today, methanol is a leading candidate in the U.S. as the transportation fuel of the future.

RESEARCH OBJECTIVE

In order to assist policy makers in consideration of methanol as a dominant U.S. transportation fuel, this report includes:

- Information on the global capacity available to produce methanol

- Estimates of the costs of production from existing capacity

- Estimates of the costs of production from capacity that may be added as demand increases, and

- Estimates of the delivered prices of methanol to selected U.S. ports during the period of transition, beginning with current market conditions (characterized by excess capacity and regionalized demand) and continuing to the point where worldwide demand exceeds available capacity.

The estimates developed in this report are based on secondary sources that provide data on current methanol production costs and engineering estimates of future costs, as available. General assumptions about the scale of future plants and efficiency improvements were also developed from secondary sources.

RESEARCH METHODOLOGY

To estimate the delivered price of methanol to selected U.S. ports, four demand scenarios were developed with the assistance of Energy and Environmental Analysis, Inc. (EEA). Because most of the current and projected near term domestic use of methanol as a vehicle fuel is in California, the scenario development is centered in California. The first two scenarios are for methanol consumption in California exclusively, with alternatives for low and high levels of consumption within the state. The two additional scenarios demonstrate a national transition, and include deliveries to ports located on the Gulf of Mexico, in the Northeast and Great Lakes regions, as well as California. Again a low and a high demand scenario are used. The levels of demand, by scenario, are shown in Exhibit 1-1.

To characterize the market conditions of supply and demand during transition, it is necessary to view each demand scenario (for U.S. transportation fuel) in terms of the global demand for methanol. Since worldwide demand for methanol includes demand that is satisfied by producers that will not also supply the U.S. because of location, political differences, etc., Exhibit 1-2 presents total demand as well as total demand less demand that will be satisfied by producers that will not supply the U.S. The additional U.S. demand assumed to be generated by methanol vehicles, by scenario, is added to other competing demand to provide total demand used to formulate the U.S. supply curve. The range of scenarios reflects periods wherein U.S. transportation demand will represent only a slight fraction of total methanol demand up to and including a scenario in which U.S. transportation demand represents more than 300

EXHIBIT 1-1:
U.S. METHANOL DEMAND SCENARIOS: TRANSPORTATION USE ONLY[1]
(Millions of Gallons)

Year	California Low Demand Case	California High Demand Case	National Low Demand Case	National High Demand Case
1988	—	7	—	—
1990	—	21	—	150
1991	11	47	138	150
1992	11	59	282	3,300
1993	22	82	421	6,500
1994	25	95	646	9,800
1995	28	108	890	13,000
1996	46	136	1,255	15,800
1997	55	154	1,670	18,600
1998	71	180	2,375	21,400
1999	103	219	3,216	24,200
2000	128	252	4,252	27,000

[1] For reference, 10,000,000 gallons would fuel approximately 15,000 vehicles for one year. (15 mpg, 10,000 mi/yr)

Source: All scenarios except the National High Demand were formulated by Energy and Environmental Analysis, Inc. (EEA) in related research undertaken for EPA, reference: EEA Working Paper #3, "Scenarios for Rapid Development of a Fuel Methanol Market in the California South Coast Basin", and EEA Working Paper #4, "A Scenario for Rapid Development of a Fuel Methanol Market in the U.S." The National High Demand Case was formulated by JFA for this effort.

EXHIBIT 1-2:

WORLDWIDE METHANOL DEMAND SCENARIOS: ALL USES

(Millions of Gallons)

		Projected Worldwide Demand, Excluding U.S. Transportation Use		Worldwide Noncaptive Demand, Including U.S. Transportation Use			
Year	Total[1]	Demand Not Competing with U.S.[2]	Demand Competing with U.S. Demand	California Low Demand Case	California High Demand Case	National Low Demand Case	National High Demand Case
1990	5,700	2,500	3,200	3,200	3,220	3,200	3,350
1995	6,900	3,000	3,900	3,930	4,010	4,890	16,900
2000	8,400	3,200	4,700	4,830	4,950	8,950	31,700

[1] A four percent growth rate for chemical methanol demand is assumed. This is because the demand for chemical methanol has been observed to increase with GNP in developed countries.

[2] It is assumed that this quantity of demand will be satisfied by countries that do not supply the U.S. As shown in Exhibit 3-3, there is 3.751 billion gallons of nameplate capacity for non-U.S. suppliers of which 625 million gallons is dedicated for conversion to gasoline (New Zealand). The remaining 3.1 billion in capacity (and future additions to that capacity) is assumed to operate at about 80 percent utilization in supplying noncompeting methanol users. Thus, the number in the table is estimated based on an assessment of available capacity, not actual market demand.

Source: EEA and JFA estimates.

percent of all other uses combined. This range of scenarios offers a framework for analysts to examine market responses under a wide array of assumptions.

To estimate the delivered price of methanol within each scenario, a supply curve for methanol was developed. The supply curve has two components: the first segment of the curve represents the short run supply of methanol available from existing (or soon to be completed) capacity. Because available capacity far exceeds current demand, producers cannot expect to receive a selling price that reflects a fully-costed product. In fact, the market now is characterized by producers who are willing to supply product if the price received is greater than variable cost. Notwithstanding this type of market imperfection, the first segment of the supply curve represents the compilation of the variable costs plus transportation costs of all individual producers and only those producers to the left of any point on the curve (those with relatively lower variable costs) will recover any fixed costs at market clearing prices. As such, the costs indicated along the supply curve should be viewed as the minimum price possible for a given level of supply and, in fact, the actual price may be higher as demand increases along the curve and higher variable cost producers are drawn into production. Market fluctuations can also result in the market price falling below variable costs, but producers will quickly adjust by reducing production to the point that price equals or exceeds variable costs. Moreover, in the spot market the price of methanol has been observed to drop below that of variable costs because supply exceeds demand at various times. This triggers producer decisions to stop production until the excess product clears the market.

The second component of the supply curve represents the long-run scenario, when demand exceeds available capacity and new capacity must be brought on line. While in the short-run excess capacity indicates that variable cost will be the controlling factor for price, in the long run (beginning at the point where available capacity is or will soon be fully utilized), entrepreneurs will require a market price that covers total costs. Thus, short of speculative investment and/or decisions to subsidize new methanol production capacity, new capacity will not be added (and long-term supply will not be increased) until the demand (and subsequently price) of methanol is high enough to cover the total production costs of methanol plants built during a future period.

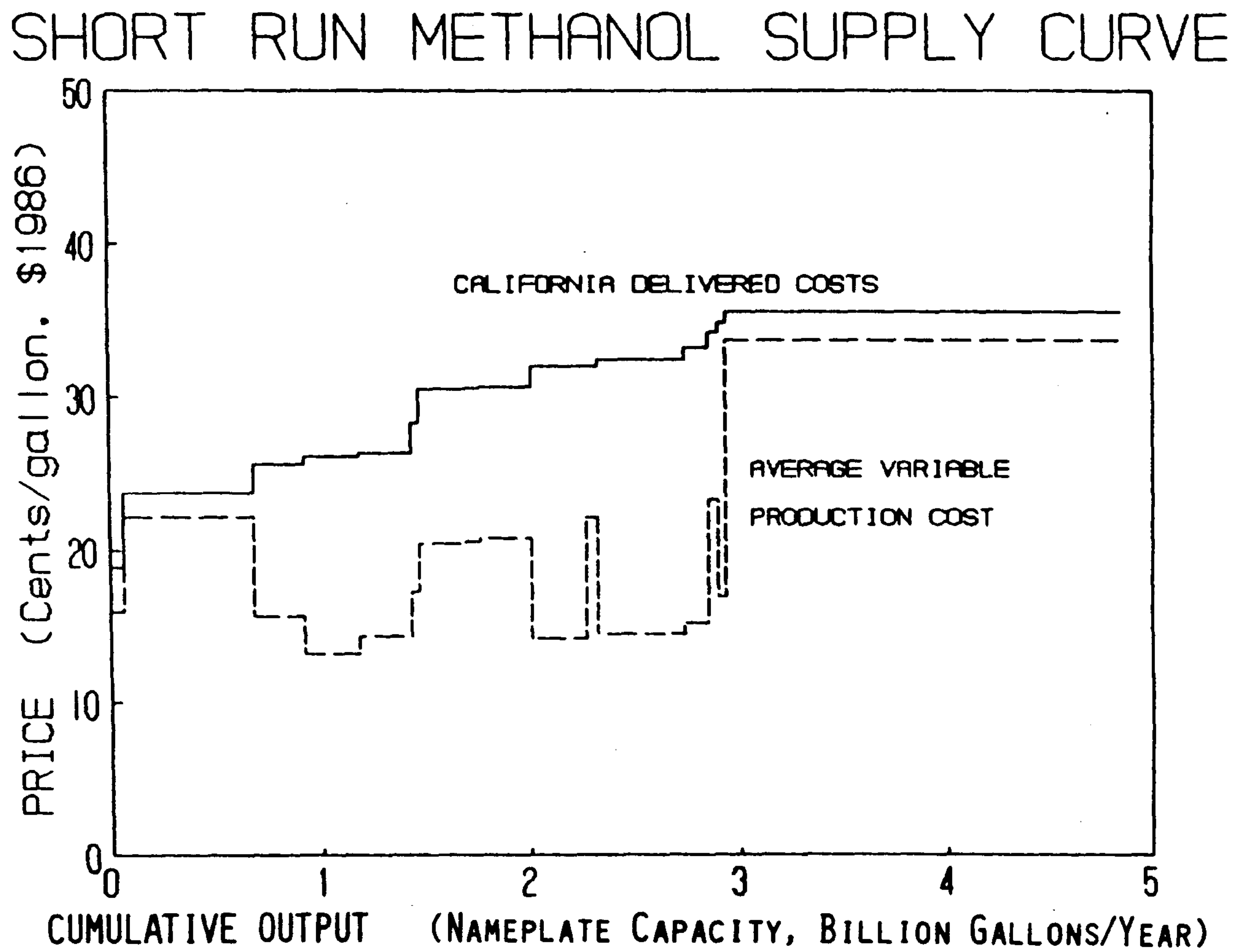
The costs of methanol in the short- and long-run scenario were developed by first distinguishing between fixed and variable costs. Costs were considered fixed costs if they lacked any connection to quantity produced, i.e., the cost of the plant in idle condition. By definition fixed costs include the actual cost of capital and the opportunity cost of capital as well as incidental costs that may be necessary to maintain the plant during idle periods. Thus, variable costs include all other costs that are associated with operation, including maintenance, overhead, selling costs, feedstock costs, etc. In the estimates presented in this report, it was necessary to combine the incidental categories of fixed costs (maintenance required when the plant is closed, base levels of utility use, property taxes, insurance, etc.) with variable costs because data were not available to identify components of primarily variable cost categories that represent fixed costs. This misstatement of fixed and variable costs does not significantly impact the numbers because the total amount of incidental fixed costs is slight when compared to total fixed costs or total variable costs. It should be noted that while consideration of marginal costs may have enhanced the analysis, reliable information on marginal costs were not available from secondary sources. Because the research undertaken indicated that plants operate at full capacity or not at all, i.e., operators run the plants in short bursts at full capacity rather than longer periods at lower capacity-utilization levels, the omission of marginal cost analysis was not considered a limiting factor.

RESEARCH RESULTS

The global supply of methanol includes product supply that is not available to the U.S. To describe the U.S. supply condition, global supply is adjusted downward to reflect only those countries that already supply or can be expected to supply methanol to the United States. An approximation of the short-run U.S. supply curve, representing the minimum delivered price of methanol from available capacity by quantity demanded, is presented in Exhibit 1-3. Each point on the curve represents the price required to cover variable production costs plus transportation costs of the least efficient producer in operation. An approximation of the long-run supply curve, as shown in Exhibit 1-4, represents estimated prices based on total production costs (fixed plus variable) plus transportation costs. In both exhibits, the higher curve represents delivered costs (including transportation to California) and the lower curve indicates the associated production costs.

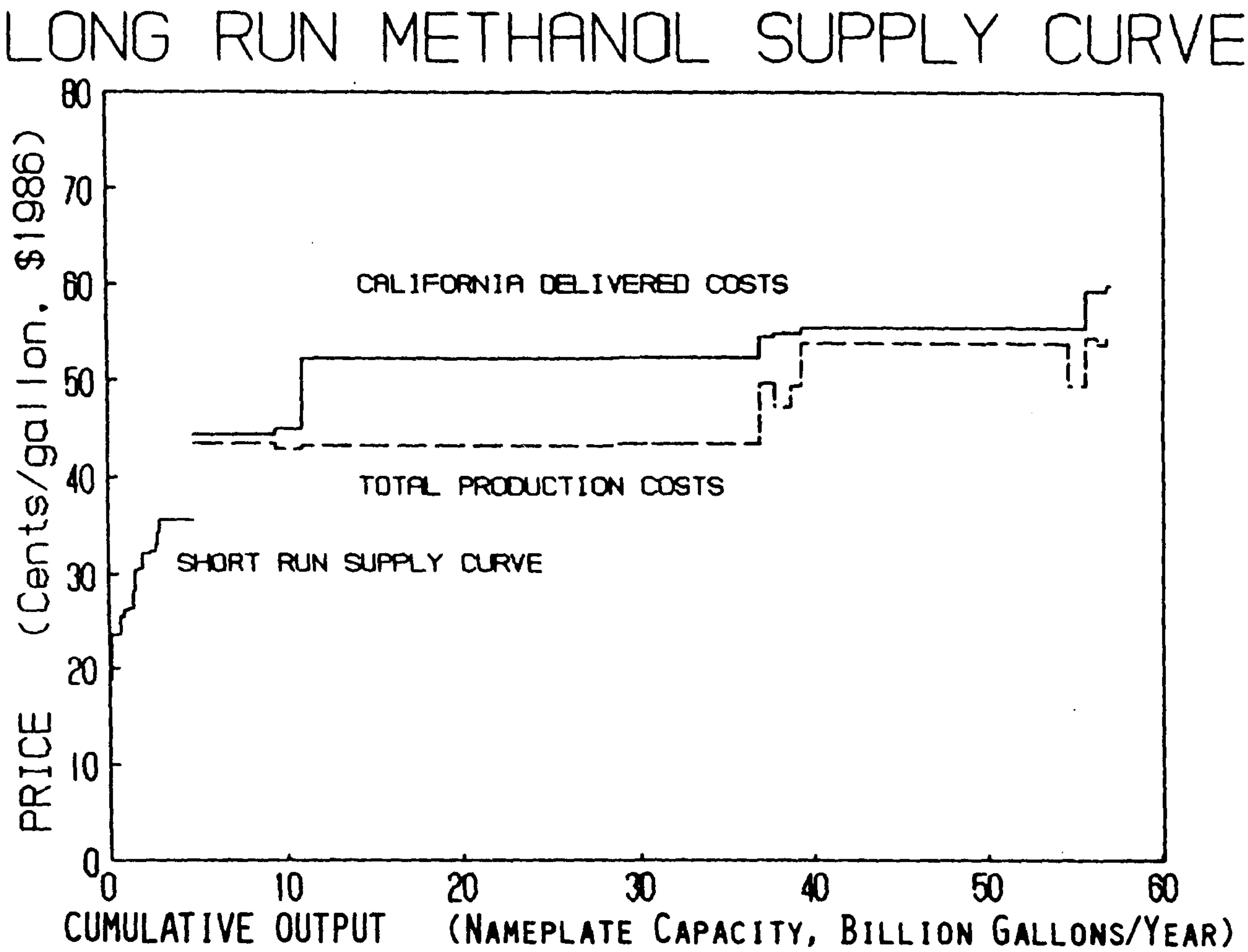
In the short run when conditions of excess capacity exist, variable costs determine price and while detailed information on fixed costs for existing capacity would be of interest, these costs cannot be reasonably estimated from secondary sources. The estimate of fixed costs would require detailed analysis of each plant based on individual construction costs, age, opportunity costs of capital, financing costs and so on. However, in the long run when capacity is designed to meet increased demand, the fixed plus variable costs will determine price. The market shift from variable cost pricing (short run) to

EXHIBIT 1-3:



COUNTRY	CAPACITY (MIL.GAL./YR)	CUMULATIVE CAPACITY (MIL.GAL./YR)	PRODUCTION COST (CENTS/GAL.)	DELIVERED PRICE (CENTS/GAL.)
1 MEXICO	60	60	15.9	18.9
2 CANADA	625	685	22.1	23.7
3 TRINIDAD	230	915	15.6	25.6
4 ARGENTINA	261	1,176	13.2	26.2
5 CHILE	250	1,426	14.4	26.4
6 BRAZIL	45	1,471	17.3	28.3
7 MALAYSIA	220	1,691	20.5	30.5
8 TAIWAN	64	1,755	20.6	30.6
9 CHINA	256	2,011	20.8	30.7
10 ARAB EMIRATES	267	2,278	14.1	32.1
11 BURMA	50	2,328	22.1	32.1
12 SAUDI ARABIA	416	2,744	14.5	32.5
13 BAHRAIN	110	2,854	15.2	33.2
14 INDIA	50	2,904	23.3	34.3
15 ALGERIA	36	2,940	16.9	34.9
16 U.S.	1,900	4,840	33.7	35.7

EXHIBIT 1-4:



COUNTRY	CAPACITY	CUMULATIVE CAPACITY	PRODUCTION COST	DELIVERED PRICE
	(MIL. GAL./YR)		(CENTS/GAL.)	
* CURRENT CAPACITY	- -	4,840	- -	- -
1 CANADA	4,600	9,440	43.4	44.4
2 MEXICO	1,500	10,940	43.0	45.0
3 ALGERIA	17,600	28,540	43.3	52.3
5 ARAB EMIRATES	2,000	30,540	43.5	52.5
4 BAHRAIN	400	30,940	43.5	52.5
6 SAUDI ARABIA	6,000	36,940	43.5	52.5
7 TRINIDAD	800	37,740	49.7	54.7
8 ARGENTINA	1,000	38,740	47.4	55.0
9 BRAZIL	600	39,340	49.5	55.0
10 U.S.	15,200	54,540	54.0	55.5
11 CHILE	1,000	55,540	49.5	55.5
12 CHINA	500	56,040	54.4	59.4
13 BURMA	100	56,140	54.4	59.4
14 MALAYSIA	600	56,740	53.7	59.4
15 INDIA	200	56,940	54.4	59.9

total cost pricing (long run) requires the careful attention of policy makers. The considerable price increase may stifle consumption and the attendent risks faced by entrepreneurs (who must invest heavily) could result in a difficult period in the transition to methanol.

The short-run curve has been superimposed onto Exhibit 1-4 to indicate the price adjustment that will be required for the market to move from short-run (less-than-fully-costed) production to long-run (fully-costed) production.

Exhibit 1-5 presents the price estimates generated from the supply assumptions described above.

In general, the cost per gallon of methanol will increase significantly as the demand for methanol grows under each transition scenario. Moreover, an unstable market will persist until the global demand for methanol approaches the level of supply that can be produced from existing capacity, approximately eight billion gallons per year. Until demand approaches the levels of available capacity, the product will be traded at a price measured by variable costs and plants will be drawn into and out of production as the price moves above or below the variable cost of individual production facilities.

REPORT OVERVIEW

The remainder of this report is organized as follows:

Chapter 2 provides a nontechnical overview of the methanol production process.

Chapter 3 discusses the supply and demand conditions at the global level, by world regions and within the U.S.

Chapter 4 sets forth the assumptions for and estimates of the production costs of current methanol producers. The variable costs (including incidental fixed costs) are detailed by the categories of feedstock, maintenance, catalyst, utility, and other costs. Fixed costs associated with capital are discussed qualitatively, no estimates are provided.

Chapter 5 examines the delivery system and presents estimates of current delivery costs and explains potential economies of scale that might be achieved in high demand scenarios.

EXHIBIT 1-5:
FORECASTED METHANOL PRICES
BY SCENARIO, FOR SELECTED YEARS
(1986 Dollars per gallon, FOB Los Angeles, Excluding Taxes)

Year	California Low Demand	California High Demand	National Low Demand	National High Demand
1990	.36	.36	.36	.36
1995	.40	.40	.45	.50
2000	.45	.45	.46	.55

Chapter 6 provides a discussion of the market changes that will move the market from variable cost pricing to fully costed (fixed plus variable costs) as demand increases. Estimates are presented for fixed, variable and total costs of future methanol capacity.

Chapter 7 summarizes the estimates presented in previous chapters into the estimated delivered cost of methanol to U.S. destinations. A discussion of the sensitivity of the estimates according to primary assumptions is also included. The recommended use of estimates, including limitations, is discussed.

Finally, general caution to all readers is appropriate. The information used to develop the estimates in this report represents an extensive collection of secondary information. The estimates reflect the data available from these sources, and averages or assumptions as noted, and the research effort was limited by the available information. Actual operating costs, by plant, were not available for current suppliers. Site-specific engineering estimates were not used to estimate the capital costs for future suppliers. Natural gas costs were developed from inference, assumptions and anecdotal information because the current prices paid by individual producers were not available and future prices in a quite different marketplace are highly speculative. Generally, the research results presented herein are a first step in understanding the current and future methanol marketplace. Additional research, comments (and criticisms) from participants in the industry and input from policy makers worldwide will enhance and refine the preliminary estimates presented here.

Comments regarding this report are encouraged and can be directed to:

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CHAPTER 2

METHANOL PRODUCTION PROCESSES

This chapter presents a general description of the chemical process and physical plant operation of methanol production. Since all available world capacity is currently operated or last operated in the production of chemical grade methanol, the following discussion is limited to chemical grade methanol processing. The production process of methyl tertiary butyl ether (MTBE), a high octane additive to gasoline that is produced from methanol, is also included.

FEEDSTOCK

According to available information, over 90 percent of the available world methanol capacity is designed for natural gas feedstock because of its higher relative hydrogen content. Higher capital costs are required to process other feedstocks (naphtha, residual oil, coal and lignite) due to their lower hydrogen content. While limited production of methanol from feedstocks other than natural gas is undertaken, these processes tend to be less efficient (naphtha, residual oil), not fully commercially tested (coal and lignite) or not commercially available (wood and other biomass processes). For these reasons the following pages are limited to a discussion of the processes used to produce methanol with natural gas as the feedstock.

PROCESS TECHNOLOGY

Prior to 1923 methanol was produced by the destructive distillation of wood from which it obtained its common name, wood alcohol. The Haber chemical process, the fundamental chemical reaction underlying all synthetic methanol production, was introduced commercially in 1923. In this process the feedstock was burned to produce a synthesis gas. Once the correct composition of synthesis gas was obtained, the conversion to methanol was obtained under high pressure and temperature in the presence of a chromium oxide - zinc oxide catalyst.

The single most important improvement in methanol production came in the 1960's, when a low-pressure synthesis process using a copper-based catalyst was developed. Methanol could then be produced by bringing a synthesis gas (primarily hydrogen and carbon monoxide) into contact with a catalyst under a relatively lower pressure (about 50 atmospheres) and at a temperature of 270° C. The steps of this process are outlined in Exhibit 2-1.

The two commonly-used low-pressure processes are the Imperial Chemical Industries' (ICI) Process, and the Lurgi Process. Every low-pressure methanol plant in the world today uses one of these or a similar process. There are many similarities between processes used worldwide, but the main differences are in the proprietary catalyst, the configuration of the feeding of the synthesis gas over the catalysts, heat recovery, and the handling of the recycle stream.

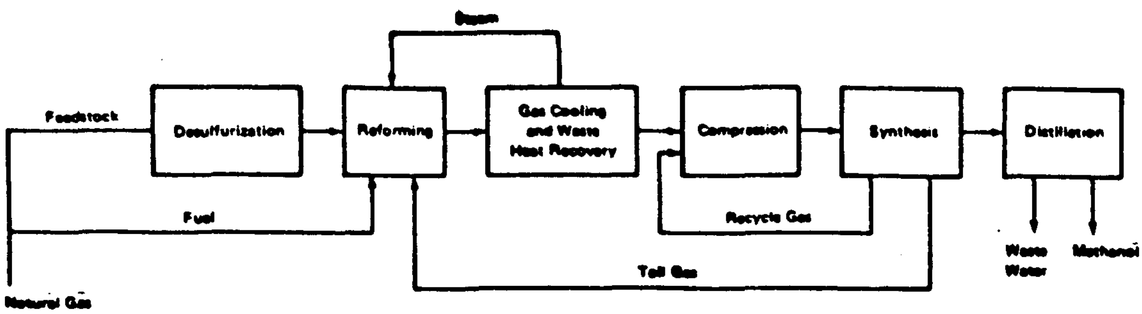
In an efficiently operated plant both the reforming catalyst and the synthesis catalyst last four to five years before the catalysts' performance fall below acceptable levels. Catalyst activity is carefully monitored by observing the conversions-per-pass in the processing cycle.

Plant size also impacts the efficiency of plant production. Plant size is usually indicated by tons-per-day. In the early 1970's 500 tons per day plants were operated by a single train and considered large. Plants built since have achieved significant economies of scale at up to 1,500 - 2,000 tons per day and are also operated with single trains though additional efficiency above this size may not be possible.

Today's methanol plants are highly instrumented and automated facilities. Under favorable conditions these plants are operated for a year or longer without shutdown. Shutdowns are either unscheduled, where unexpected mechanical or catalyst problems have developed, or scheduled at 12-18 month intervals to do periodic maintenance and, if needed, change-out the catalyst charges. Day-to-day operating considerations are worker safety, protecting the plant from damage, yields, product quality and thermal efficiency.

Many methanol plants are located within a chemical or refinery complex and are integrated within that complex with respect to hydrocarbon supply and utilization, energy conservation and plant management. In U.S. petrochemical plants and refineries, periodic maintenance is generally performed by independent contractors. In areas where these units are concentrated, contract maintenance and plant "turn-arounds" by maintenance contractors have many advantages including lower year-round staff costs for the plant operator. The only reasonable efficiency improvement

EXHIBIT 2-1:
SIMPLIFIED GAS-BASED METHANOL PRODUCTION PROCESS



Steps

1. Desulfurization of feedstock to remove sulfur compounds that would otherwise poison the reforming and synthesis catalysts.

2. Feedstock is reformed and cooled, which means it is combined with steam at a specific ratio, preheated and distributed to nickel-based catalyst-filled tubes in the reformer radiant section. The reformer furnace is fired by the feedstock and tail gas from the synthesis step.

Basic Reactions Occurring:

$$CH_4\text{(methane)} + H_2O \rightarrow CO + 3H_2 \text{ and}$$

$$CO + H_2O \rightarrow CO_2 + H_2$$

3. This synthesis gas, composed mainly of carbon monoxide, hydrogen, carbon dioxide and some unconverted methane, leaves the reformer, and is subjected to several gas-cooling steps. These steps utilize heat-recovery to save heat for use in power generation, preheating, and reboiling purposes in the following distillation step.

4. The next step is synthesis gas compression: the synthesis gas is compressed by a steam turbine-driven compressor to the synthesis pressure.

5. The compressed gas is combined with an unconverted recycle stream (already compressed in a recycle gas compressor), preheated in a heat exchanger, and delivered to the methanol converter within the methanol synthesis step.

Basic Reactions in Converter are:

$$2H_2 + CO \rightarrow CH_3OH \text{ (methanol) and}$$

$$3H_2 + CO_2 \rightarrow CH_3OH + H_2O$$

6. The water and other compounds (resulting from side reactions) are removed in the final distillation step.

Source: World Bank, Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries. April 1982.

related to existing plant operation would be improvement of the catalyst to permit lower pressure processing.

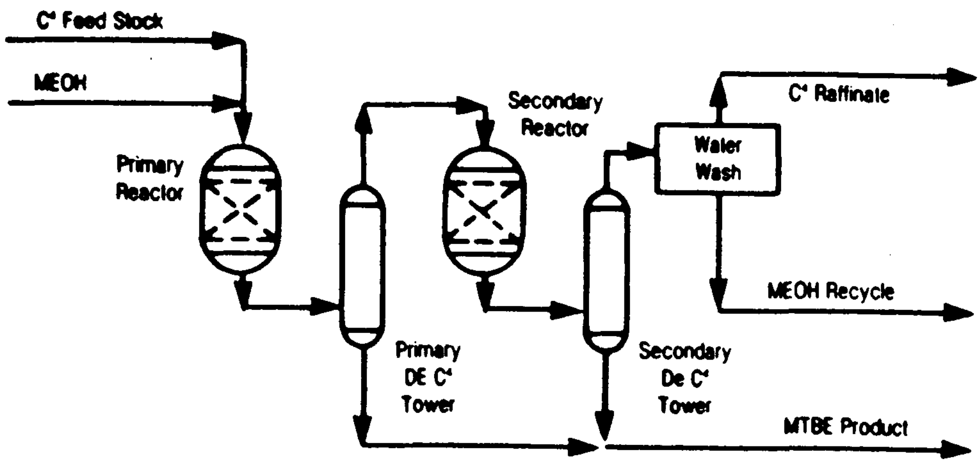
In summary, a large percent of the available world-wide capacity for the production of methanol is characterized by a natural-gas fed plant operated by a low-pressure process fed by a single train and capable of processing 1500 or more tons per day. The plants are frequently operated within a refinery and physical inputs are characterized by the feedstock and catalysts, which must be replaced every 4-5 years. Moreover, older plants may utilize a less-efficient high-pressure process or be smaller and fail to achieve the economies of scale associated with the larger (newer) plants. A limited number of plants are designed to use residual oil or naptha as a feedstock. The use of coal/lignite as a feedstock is in the commercial-testing phase and no commercial plants operate using wood or other biomass feedstock.

Methyl tertiary butyl ether (MTBE) is a product produced from methanol that has gained acceptance as a high-octane fuel additive. MTBE, like methanol, is well suited for refinery production. The production of MTBE from methanol is described below.

METHYL TERTIARY BUTYL ETHER

Methyl tertiary butyl ether (MTBE) is one of the most popular of the recently developed uses of methanol. It is an excellent high-octane additive because it is completely compatible with gasoline, is relatively inexpensive to produce, and the transportation and distribution pose no major problems. For these reasons, MTBE has frequently replaced toluene as the standard octane-enhancer. The MTBE process is a means of converting isobutylene into a quality blending agent well suited for alkylation operations at many refineries (see Exhibit 2-2).

EXHIBIT 2-2:
TWO-STAGE MTBE PROCESS



Important Characteristics

- The MTBE process is well suited for large refinery/petrochemical facilities, because the isobutylene required for the etherification of the methanol feedstock is available from several other petrochemical production streams.
- The MTBE process is capable of operating on a mixed butane/butylene stream.
- The MTBE process can be located anywhere isobutylene is available at market prices.
- Methanol accounts for roughly one-third of the feestock of the MTBE process.

Source: Department of Commerce, A Competitive Assessment of the U.S. Methanol Industry. May 1985.

CHAPTER 3

WORLD METHANOL CAPACITY

This chapter presents estimated world methanol capacity and examines the supply-demand relationships by major regions. The estimates developed in this study represent the first comprehensive plant-specific estimates of global capacity and were derived from a wide range of sources. As such, the estimates are subject to considerble error.

Plant specific data on world methanol capacity is unreliable and estimates available from the various sources are often conflicting. Information on individual plant capacities, production processes, feedstocks and ownership for North America, Western Europe, and Japan are available in the Chemical Economics Handbook (Stanford Research Institute), but this information is somewhat dated. The United Nations Industrial Development Organization (UNIDO) has provided information on capacities in the developing and selected developed countries by country and year, however, some guesswork is often required to infer individual plant capacities from this data. Information on the plant capacities in the Eastern Bloc countries is even more aggregated and contradictory than that for the developing countries. Numerous other sources provide information on U.S. capacity as well as data on selected new plants.

Exhibit 3-1 provides estimates of plant capacities, production processes, feedstocks and ownership by plant and country. These estimates were developed through the comparison of all available information provided in the various sources listed at the end of the exhibit. Plant capacities that are presented represent plants that were identified in at least two sources. The footnotes contain the actual estimates provided in the sources along with the expected opening date for plants under construction or in planning stages. New plants that were listed in only one source and were not substantiated by any other source are shown with zero capacity. Plants that were identified as shutdown were included if it was believed that they were capable of reopening and if they had operated recently (since 1983) Additionally, for U.S. plants, the location of the plant and last known status (if not operating) is indicated.

Most sources of capacity data are stated in nameplate capacity, the theoretical upper limit of a plant's productive ability. It is the maximum theoretical annual output under ideal working conditions. No plant, under normal circumstances, ever achieves this level of efficiency. There are usually shutdowns for routine maintenance and/or for

EXHIBIT 3-1:

IDENTIFIED ESTIMATES OF METHANOL CAPACITY BY PLANT AND COUNTRY, 1990 (Millions of Gallons)

(Conversion Factor: 334.5 gallons per metric ton)

(Conversion Factor: 227.5 million gallons/year = 2000 tons/day)

Location	Capacity (Mil. Gal./Yr.)	Feedstock (Process)	Ownership
NORTH AMERICA			
United States	60 [1]	Natural Gas (ICI Low Pressure)[2]	Air Products[2]-Pensacola, FL
	130 [3]	Natural Gas (Lurgi Low Pressure)[2]	Allemania[2]-Plaquemine, LA (temp closed 7/84)
	200 [4]	Natural Gas (ICI Low Pressure)[2]	ARCO Chemical[2]-Houston, TX
	200 [5]	Natural Gas (ICI Low Pressure)[2]	Borden Chemical[2]-Geismar, LA (partially closed)
	150 [6]	Natural Gas (Lurgi Low Pressure)[2]	Celanese Chemical[2]-Bishop, TX
	230 [7]	Natural Gas (ICI Low Pressure)[2]	Celanese Chemical[2]-Clear Lake, TX (closed)
	250 [8]	Residual Fuel Oil (Lurgi Low Pressure)[2]	Du Pont[2]-Deer Park, TX (closed)
	200 [9]	Natural Gas (Lurgi Low Pressure)[2]	Du Pont[2]-Beaumont, TX
	126 [10]	Natural Gas (ICI Low Pressure)[2]	Georgia Pacific[2]-Plaquemine, LA
	100 [11]	Refinery Gas (Lurgi Low Pressure)[2]	Texaco[2]-Delaware City, DE (mothballed)
	100 [12]	Natural Gas (ICI Low Pressure)[2]	Monsanto[2]-Texas City, TX (may soon close)
	135 [13]	Natural Gas (Lurgi Low Pressure)[2]	Tenneco[2]-Houston, TX
	60 [14]	Coal (Lurgi Low Pressure)[2]	Tennessee Eastman[2]-Kingsport, TN
	1,941		
Canada	240 [15]	Natural Gas (ICI Low Pressure)[16]	Alberta Gas Chemicals Limited[17]
	240 [18]	Natural Gas (ICI Low Pressure)[16]	Celanese Canada[17]
	145 [19]	Natural Gas[16]	Ocelot Industries Limited[17]
	0 [20]	———	Alberta Gas Chemicals Limited[20]
	0 [21]	———	Biewag Energy Resources Limited[21]
	625		
Mexico	57 [22]	Natural Gas[2]	PEMEX[2]
	0 [23]	———	PEMEX[24]
	57		
WESTERN EUROPE			
Austria	20 [1]	———	———
France	72 [2]	Natural Gas (ICI Low/Medium Pressure)[3]	Association du Methanol de Villers Saint-Paul[3]
	25 [2]	Natural Gas[3]	Pechiney Vgine Kuhlmann SA[3]
	40 [2]	Natural Gas[3]	Societe Methanolacq SA[3]
	137		
Italy	20 [4]	Refinery off-gas (Montedison)[3]	Eni Chem[3]
	39 [4]	Natural Gas (Fauser)[3]	Eni Chem[3]
	59		
Netherlands	248 [5]	Natural Gas (ICI Low/Medium Pressure)[3]	Methanor VoF[3]
	0 [6]	———	Methanor[7]
	248		
Norway	20 [8]	Natural Gas (ICI Process)[3]	Norsk Hydro a.s. (51% State owned)[3]
	0 [9]	———	DYNO[3]
	20		
Spain	67 [10]	Refinery off-gas (ICI Low Pressure)[3]	Compania Espanola de Petroleos[3]
Sweden	0 [11]	———	———
United Kingdom	221 [12]	Natural Gas (ICI Low/Medium Pressure)[3]	Imperial Chemical Industries (ICI)[3]
West Germany	80 [13]	Natural Gas (BASF Process)[3]	BASF Aktiengesellschaft[3]
	67 [13]	Heavy Oil[3]	Chemische Werke Huels AG[3]
	134 [13]	Heavy Oil[3]	Union Rheinische Braunkohlen Kraftstoff AG[3]
	0 [14]	———	Shell
	281		

EXHIBIT 3-1: — (continued)

IDENTIFIED ESTIMATES OF METHANOL CAPACITY BY PLANT AND COUNTRY, 1990 (Millions of Gallons)

(Conversion Factor: 334.5 gallons per metric ton)

(Conversion Factor: 227.5 million gallons/year = 2000 tons/day)

Location	Capacity (Mil. Gal./Yr.)	Feedstock (Process)	Ownership
LATIN AMERICA			
Argentina	11 [1]	Natural Gas [10]	—
	200 [2]	Natural Gas [10]	Petroquimica Austral[3], Huarpes[4]
	50 [2]	Natural Gas [10]	Recinfor[3]
	261		
Bolivia	12 [5]	Natural Gas [10]	—
Brazil	45 [6]	Natural Gas [10]	—
Chile	250 [7]	Natural Gas [10]	Signal Group[3]
Trinidad	130 [8]	Natural Gas [10]	—
	100 [9]	Natural Gas [10]	NEC[3]
	230		
AFRICA			
Algeria	36 [1]	Natural Gas [6]	—
Libya	110 [2]	Natural Gas [6]	—
	110 [3]	Natural Gas [6]	NMC[4], State[5]
	220		
MIDDLE EAST			
Saudi Arabia	200 [1]	Natural Gas [7]	Sabic/Japan[2]
	216 [3]	Natural Gas [7]	Sabic/Celanese[2]
	416		
Bahrain	110 [4]	Natural Gas [7]	Gulf Petrochemicals[5], GPIC[2]
U.A. Emirates (Sharjah)	267 [6]	Natural Gas [7]	—
ASIA			
Burma	50 [1]	Natural Gas [14]	—
Bangladesh	0 [2]	—	Beximco[2]
China	87 [3]	Natural Gas [14]	—
	35 [3]	Natural Gas [14]	—
	134 [4]	Natural Gas [14]	—
	256		
India	30 [5]	Natural Gas [14]	—
	20 [5]	Natural Gas [14]	—
	50		
Korea	110 [7]	Natural Gas [14]	—
Malaysia	110 [8]	Natural Gas [14]	Petronas[9], Sabah[10]
	110 [8]	Natural Gas [14]	Bordon[9], Sabah[10]
	220		
Philippines	7 [11]	Natural Gas [14]	—
Taiwan	64 [12]	Natural Gas [14]	CPDC[9]
	0 [13]	—	—
	64		

EXHIBIT 3-1: — (continued)

IDENTIFIED ESTIMATES OF METHANOL CAPACITY BY PLANT AND COUNTRY, 1990 (Millions of Gallons)

(Conversion Factor: 334.5 gallons per metric ton)

(Conversion Factor: 227.5 million gallons/year = 2000 tons/day)

Location	Capacity (Mil. Gal./Yr.)	Feedstock (Process)	Ownership
OTHER PACIFIC			
Japan	133 [1]	Natural Gas (Mitsubishi Process)[2]	Mitsubishi Gas Chemical Co., Inc.[2]
	44 [1]	Natural Gas (Mitsubishi Process)[2]	Mitsui Toatsu Chemicals, Inc.[2]
	0 [3]	———	———
	177		
Australia	0 [4]	———	———
New Zealand	130 [5]	———	Petral Gas[6]
	495 [6,7]	Natural Gas [9]	Petral Gas[8], N2/Mobil[6]
	625		
Indonesia	114	Natural Gas (Lurgi)	———
EASTERN BLOCK			
East Germany	200 [1]	———	Industrie Analgen[2]
U.S.S.R	700 [3]	———	———
	270 [4]	(ICI)[5]	State[6]
	0 [4]	(ICI)[5]	———
	970		
Yugoslavia	310 [7]	———	———
	67 [8]	———	MSK[2]
	377		
WORLD TOTAL	8,743		

SOURCES

(UN 85) Current World Situation in Petrochemicals, UNIDO/PC.126 United Nations Industrial Development Organization, November 14, 1985, Annex 1 and Annex 2, and a special supplement entitled Methanol Capacities in the Developing Countries, provided by UNIDO Sectoral Studies Branch, Vienna, Austria.

(CB 84) "More Hitches in Methanol's Growth Plan", Chemical Business, June 1984, p. 28.

(JPL 83) Jet Propulsion Laboratory, California Methanol Assessment, Volume II: Technical Report, pp. 7-7, 7-8.

(TENN 85) Simmons, Richard E. (Sales Manager for Methanol of Tenneco Oil Company), Methanol-World Supply/Demand Outlook, presented at the 1985 National Conference on Alcohol Fuels, Renewable Fuels Association, Washington, D.C., September 1985.

(DOC 85) Department of Commerce, A Competitive Assessment of the U.S. Methanol Industry, May 1985, p. 35.

(WMC 85) Papers presented at the "1985 World Methanol Conference", especially paper IV, p. 3.

(CHEV 84) Chevron U.S.A. Inc., The Outlook for Use of Methanol as a Transportation Fuel, November 1984, Table 1-1.

(SRI 83) Stanford Research Institute International, Chemical Economics Handbook, October 1983, pp. 674.5022J, 674.5022K, 674.5025B, 674.5025F, 674.5025G, 674.5022K.

EXHIBIT 3-1: (continued)

FOOTNOTES

For each footnote capacity is given in million gallons per year as provided in the reference document (except where it has been converted from metric tons). Following the capacity figures are source citations as provided above. For example, the first footnote indicates that sources (CB 84), (WMC 85), (CHEV 84) and (DOC 85) reported capacity for this plant as 60 million gallons per year, while the source (SRI 83) reported capacity for this plant as 50 million gallons per year.

The (*) denotes that plant capacity, which is shown in million gallons per year, was converted from metric ton data in the original source. This conversion is based on a factor of 334.5 gallons per metric ton. This factor was derived from the number of pounds in a metric ton (2204.6) and the number of pounds in a gallon of methanol (6.59). The number of pounds in a gallon of methanol is from Arthur M. Brownstein, U.S. Petrochemicals, The Petroleum Publishing Company, Tulsa, Oklahoma, 1972, p. 81.

Footnotes for North America

1. 60 (CB 84) (WMC 85) (CHEV 84) (DOC 85), 50(SRI83).
2. (SRI 83).
3. 130(CB 84) (WMC 85) (CHEV 84) (DOC 85) (SRI 83).
4. 200 (CB 84) (WMC 85) (CHEV 84) (DOC 85) (SRI 83).
5. 200 (CB 84) (WMC 85), 190 (CHEV 84), 210 (DOC 85), 200-210 (SRI 83).
6. 150 (CB 84) (WMC 85) (CHEV 84) (SRI 83), 145 (DOC 85).
7. 200 (CB 84), 230 (WMC 85) (CHEV 84) (DOC 85) (SRI 83).
8. 250 (CB 84) (WMC 85) (DOC 85), 225 (CHEV 84), 200 (SRI 83).
9. 200 (CB 84) (WMC 85) (CHEV 84) (DOC 85), 250 (SRI 83).
10. 126 (CB 84) (WMC 85), 120 (CHEV 84) (SRI 83), 130 (DOC 85).
11. 100 (CB 84) (WMC 85) (CHEV 84) (DOC 85) (SRI 83).
12. 105 (CB 84), 100 (WMC 85) (CHEV 84) (DOC 85) (SRI 83).
13. 135 (CB 84) (CHEV 84), 130 (WMC 85) (SRI 83), 150 (DOC 85).
14. 0 (CB 84), 60 (WMC 85) (DOC 85), 65 (CHEV 84), 50-65 (SRI 83).
15. 240 (CB 84), 240.8* (SRI 83).
16. (SRI 83).
17. (CB 84) (SRI 83).
18. 240 (CB 84), 234.2* (SRI 83).
19. 145 (CB 84), 133.8* (SRI 83).
20. 240 (CB 84), 0 (DOC 85). Alberta Gas Chemicals Limited Plant in Scotford, Alberta. No target date; no site work started yet (CB 84).
21. 530 (CB 84), 0 (DOC 85). Biewag Energy Resources, Ltd., plant in Waskatenau, Alberta. No target date; still seeking government approvals (CB 84).
22. 57.2* (UN 85), 57 (CB 84), 57.5* (SRI 83).
23. 218.8* (UN 85), 275 (CB 84), 270 (JPL 83), 220 (DOC 85). To be added in 1988 (UN 85), in 1986, or later (CB 84), 1985 (JPL 83), planned or under construction (DOC 85).
24. (JPL 83).

Footnotes for Europe

1. 30 (DOC 85), 22.1* (TENN 85).
2. 100 (DOC 85), 132 (CB 84), 97*(TENN 85), 137.1* — 3 plants of 71.9*, 25.1*, 40.1* — (SRI 83).
3. (SRI 83).

EXHIBIT 3-1: (continued)

Footnotes for Europe — (continued)

4. 35 (DOC 85), 93 (CB 84), 67*(TENN 85), 58.5* — 2 plants of 20.1*, 38.5* —(SRI 83).
5. 230 (DOC 85), 240 (CB 84), 247.5*(SRI 83).
6. 140 (JPL 83), 0 (DOC 85), 0 (CB 84). To be added in 1986 (JPL 83), planned or under construction (DOC 85).
7. (JPL 83).
8. 20.1* (TENN 85), 20.1* (SRI 83).
9. 170 to be added in 1988 (JPL 83).
10. 68 (CB 84), 73.6* TENN, 66.9* (SRI 83)
11. Proposed capacity of 233 (CB 84).
12. 240 (DOC 85), 270 (JPL), 220.8* (SRI 83).
13. 275 (DOC 85), 223 (CB 84), 281* — 3 plants of 80.3*, 66.9*, 133.8* — (SRI 83).
14. 0 (DOC 85), 0 (CB 84), 130 to be added in 1987 (JPL 83).

Footnotes for Latin America

1. 12.0* (UN 85), 11 (CB 84), or 10 (DOC 85)
2. 228.8* (UN 85), 100 (CB 84), 250.9* — plants 200.7* and 50.2* —TENN (85), 200 (JPL 83), (DOC 85). To be added to capacity in 1988 (UN 85), target 1987-1988 + (CB 84), 1988-1989 (TENN 85), 1986 (JPL 83).
3. (TENN 85)
4. (JPL 83)
5. 12.4* (UN 85).
6. 56.9* (UN 85), 30 (CB 84), 45 (DOC 85). Note: UN 85 shows capacity in Brazil at 51.2* in 1983-1984, increasing to 56.9 in 1985 and to 70.2 in 1988.
7. 254.2* (UN 85), 280 (CB 84), 200.7 (TENN 85), 250 (DOC 85). To be added to capacity in 1988 (UN 85), planning stage, no target date (CB 84), 1988-1989 (TENN 85).
8. 130.5* (UN 85), 145 (CB 84), 110 (JPL 83), 140 (DOC 85).
9. 89.0* in unspecified Latin American country (UN 85), 0.0 (CB 84), 100.4 (TENN 85), 0.0 (JPL 83), 340 (DOC 85).
10. This plant is assumed to use natural gas as a feedstock based on the authors general knowledge of the methanol industry. No specific reference was available.

Footnotes for Africa

1. 36.8* (UN 85) or 36 (CB 84).
2. 110.4* (UN 85) or 0.0 (CB 84).
3. 110.4* (UN 85), 120 (CB 84), 100.4* (TENN 85), 110 (JPL 83). To be added to capacity in 1986 (UN 85), reportedly 1985 (CB 84), 1985-1986 (TENN 85), 1984 (JPL 83).
4. (JPL 83).
5. (TENN 85).
6. This plant is assumed to use natural gas as a feedstock based on the authors general knowledge of the methanol industry. No specific reference was available.

Footnotes for the Middle East

1. 200.7* (UN 85), 200 (CB 84) or 220 (JPL 83). To be added to capacity in 1983 (UN 85), 1984 (CB 84), 1984 (JPL 83).

EXHIBIT 3-1: (continued)

Footnotes for the Middle East — (continued)

2. (JPL 83).
3. 217.4* (UN 85), 216 (CB 84) or 220 (JPL 83). To be added to capacity in 1984 (UN 85), 1985 (CB 84), 1985 (JPL 83).
4. 110.4* (UN 85), 120 (CB 84), 100.4* (TENN 85), 110 (JPL 83). To be added to capacity in 1985 (UN 85), early 1985 (CB 84), 1985-1986 (TENN 85), 1985 (JPL 83).
5. (TENN 85).
6. 267.6* at unspecified Middle East location (UN 85), 432 (CB 84), 167.3 in Sharjah (TENN 85). To be added to capacity in 1985-1990 (UN 85), late 1980's (CB 84), 1988-1989 (TENN 85).
7. This plant is assumed to use natural gas as a feedstock based on the authors general knowledge of the methanol industry. No specific reference was available.

Footnotes for Asia

1. 50.2*(UN 85), 55 (CB 84), 50.2* (TENN 85), 50 (DOC 85). Existing (UN 85), probably added in 1986 (CB 84), to be added 1985-1986 (TENN 85).
2. 110 (DOC 85), 110 (JPL 83). Planned or under construction (DOC 85), to be added in 1986 (JPL 83).
3. 133.8* — 2 plants 87.0* and 46.8* — (UN 85), 35 (JPL 83), 35 (DOC 85).
4. 133.8* (UN 85), 35 (DOC 85). Added in 1989 (UN 85).
5. 45.2* (UN 85), 27 (CB 84), 30 (DOC 85).
6. 0.0 (UN 85), 17 (CB 84), 20.1* (TENN 85), 20 (DOC 85). Planning stages (CB 84), to be added in 1985-1986 (TENN 85).
7. 110.4* (UN 85), 18 (CB 84), 0.0 (DOC 85)
8. 200.7* (UN 85), 240 (CB 84), 200.7 (TENN 85), 220 — 2 plants 110 each — (JPL 83), to be added in 1985 or before (UN 85), planned, no target date (CB 84), 1985-1986 (TENN 85), 1986 (JPL 83).
9. (JPL 83).
10. (TENN 85).
11. 6.7* (UN 85).
12. 63.6* (UN 85), 232 (CB 84), 35 (JPL 83), 20 (DOC 85), existing capacity except (JPL 83) which shows addition in 1983.
13. 220 (CB 84), 0.0 (DOC 85). To be added in early 1984 (CB 84).
14. This plant is assumed to use natural gas as a feedstock based on the authors general knowledge of the methanol industry. No specific reference was available.

Footnotes for Other Pacific

1. 133.8* (UN 85), 117 (CB 84), 130 (DOC 85), 176.6* — 2 plants of 132.5* and 44.2* (SRI 83).
2. (SRI 83).
3. 0 (UN 85), 33 (CB 84), neg. (DOC 85), 200 (JPL 83). Planning stages, no date (CB 84), planned or under construction (DOC 85), to be added in 1985 (JPL 83).
4. 110 (DOC 85), planned or under construction.
5. 135 (CB 84), 130 (DOC 85), 130 to be added in 1984 (JPL 83).
6. 0 (JPL 83) (CB 84), 495 (DOC 85), 501.8* (TENN 85), 200 (JPL 83), planned or under construction (DOC 85), to be added in 1985-1986 (TENN 85), to be added in 1987 (JPL 83).
7. For conversion to gasoline (TENN 85), for conversion to gasoline by the Mobile MTG process (DOC 85).
8. (TENN 85).
9. This plant is assumed to use natural gas as a feedstock based on the authors general knowledge of the methanol industry. No specific reference was available.

EXHIBIT 3-1: (continued)

Footnotes for Eastern Block

1. 200.7* (TENN 85). To be added to capacity in 1985-1986.
2. (TENN 85).
3. 700 (CB 84) capacity is most likely in several plants but no information on individual plants was available.
4. 270.9* (TENN 85), 270 (JPL 83), 600 — 2 plants — (CB 84), to be added in 1985-1986 (TENN 85), in 1983 (JPL 83), in 1984-1985 (CB 84).
5. (CB 84).
6. (JPL 83).
7. 310 (CB 84) Figure for East Block Nations other than U.S.S.R.
8. 66.9* (TENN 85), 135 (JPL 83). To be added in 1985-1986 (TENN 85), in 1982 (JPL 83).

equipment breakdowns. Most observers believe that 90 percent nameplate capacity is a reliable indication of maximum annual output. Thus, a reasonable indicator of maximum available capacity is 90 percent of the capacity shown in Exhibit 3-1. The capacities in the various sources were stated in one of three ways: (1) millions of gallons per year, (2) tons per year or (3) tons per day. These estimates were translated into millions of gallons per year (if required) by converting tons to gallons (334.5 gallons/ton). Per day capacities were annualized based on 340 operating days/year. This represents an ideal engineering capacity, allowing appropriate time for current and preventative maintenance. In addition, factors such as weather, input difficulties, shipping and other natural and market occurrences will result in actual output less than potential. (Another useful equivalence is that 2000 tons/day equals 227.5 million gallons/year.)

Today's methanol producers primarily supply chemical grade methanol to chemical plants worldwide. The market for chemical methanol is characterized by tremendous excess capacity relative to the current levels of demand and considerable surpluses of product on the market in recent years. Product price has fallen to quite low levels resulting in the closure of a number of plants, usually (or hopefully) on a temporary basis. As mentioned above, the capacity estimates in Exhibit 3-1 include plants that are closed but still believed to be in operable condition. The generating status of U.S. plants, as of January 1986, is given in the exhibit. Due to limited resources the status of all other plants worldwide could not be verified.

In spite of the poor market conditions facing the methanol industry, it is interesting to observe the amount of capacity that has been or is scheduled to be added to world capacity. Moreover, it is unlikely that the large amounts of capacity additions have been made based on the stable but relatively slow growth trend (2-3 percent above GNP in the U.S.) of the demand for chemical methanol. It is easier to speculate that producers are positioning themselves for an expanded market demand. Growth in the demand for fuel methanol or methanol derivatives such as MTBE are favorable candidates.

WORLD METHANOL SUPPLY AND DEMAND

The pattern of global methanol consumption relative to capacity in millions of gallons since 1980 is as follows[1]:

	1980	1981	1982	1983	1984
Total Available (100%) Capacity:	4,783	4,984	5,051	5,452	5,285
Consumption:	3,880	3,613	3,579	3,947	4,215
Surplus Capacity:	903	1,371	1,472	1,505	1,070
Percent Plant Utilization:*	81	72	71	72	80

*Note that 90% of utilization is the expected operating level of an efficient plant.

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[1] Data through 1984 calculated from data in "Methanol World Balance" by Robert Coxon as presented to the 1985 World Methanol Conference, Amsterdam, December 1985. Data are converted from metric tons: One metric ton equals 334.5 gallons of methanol.

It should be noted that the capacity shown in Exhibit 3-1 includes capacity built since 1984 as well as plants recently closed. Coxon's estimates have been adjusted for plant closures. Moreover, by 1990 the numbers become more dramatic. According to the identified capacity listed in Exhibit 3-1, available nameplate capacity (100%) would equal 8,100 million gallons, excluding 625 million gallons of capacity in New Zealand that is earmarked for conversion to gasoline. If consumption for chemical uses rises at the 4.0 percent per year, demand will increase to about 5,300 million gallons. Others, such as the World Bank and the 1985 Methanol Conference have suggested higher 1990 demands of about 5,700 million gallons (a 5.2% increase, see Exhibit 3-2). The implied surplus capacity in 1990 would be 2,400-2,800 million gallons. This is nearly 200 percent of the 1983 surplus, the highest level of excess capacity since 1980. The capacity utilization rate would be approximately 68 percent (the desirable utilization is 90 percent). Of course, if conditions such as these do occur, it is likely that some portion of the available capacity that has been or will be temporarily closed will be permanently closed/dismantled thereby reducing the surplus capacity. To the extent that investors wish to hold on to capacity, the plants can be shut-down and operated periodically (as demand/price levels for methanol permit) or with new technology removed and mounted on a floating platform to take advantage of low feedstock and/or transportation costs that might be available to a "floating" plant that would not be available to a stationary plant. While the world balance of supply and demand for chemical methanol depict a universal surplus of methanol, specific world regions will be affected more directly by local conditions of supply and demand, as discussed below.

LOCAL METHANOL SUPPLY AND DEMAND

The projected capacity/supply and demand for chemical methanol (millions of gallons) in 1990 is estimated in Exhibit 3-2. However, the estimates are misleading. In North America, the U.S. has shutdown considerable capacity as is also true in Western Europe. Thus, while it is possible for the U.S. and Western Europe to supply much of their methanol requirements, the current situation is that demand requirements are more and more being filled by lower-cost imported methanol. The U.S. imports primarily from Canada and South America and Western Europe imports from other surplus producers. Japan has the largest demand in the Far East/Asia and also imports much of its requirements.

In general, the current (depressed) marketplace is dictated by countries that produce with relatively lower cost that are located in South America, the Middle East and Asia. This situation will continue unless additional demand supports production from higher cost producers in North America and Western Europe. In fact, if current conditions persist, production in North America and Western Europe will continue to drop. Moreover, even if demand and price begin to climb, it is possible that additional demand, in the long run, will be met by added capacity for low-cost producing regions rather than by available (but underutilized) capacity in North America or Western Europe.

U.S. METHANOL SUPPLY

For this analysis it is necessary to determine which countries are potential suppliers of methanol to the United States. Exhibit 3-3 presents a listing of methanol producers and the availability of their supply to the U.S. It has been determined that the methanol produced in several countries would not be available to the U.S. for numerous reasons. These include:

- Country is situated in a net import region — several regions, especially Europe, are characterized as large net importers. It would be inefficient for a European producer to export product to the U.S., given the high transportation costs, when substantial market opportunities are available in that region. It is also assumed that Korea will export any excess supply to Japan based on the same reasoning.

EXHIBIT 3-2:

LOCAL METHANOL SUPPLY AND DEMAND, 1990

(Millions of Gallons)

Region	Demand[1] (World Methanol Conference)	Demand[2] (World Bank)	Available Supply[3]	Surplus (World Methanol Conference)	Surplus (World Bank)
North America	1,888	1,828	2,361	473	533
Western Europe	1,474	1,748	948	(526)	(800)
Far East/Asia	1,339	855	1,060	(279)	205
South America	103	120	718	615	598
Mid East/Africa	103	60	944	841	884
Eastern Europe	926	1,075	1,392	466	317
World Total	5,833	5,686	7,423	1,590	1,737

[1] "Methanol: The More Distant Future," by James R. Crocco, presented to the 1985 World Methanol Conference, The Netherlands, December 1985. Note that regional distributions are approximated based on graphs presented.

[2] World Bank, Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries, April 1982, p.48.

[3] Calculated from Exhibit 3-1, 90 percent of nameplate capacity. In addition, 495 million gallons of capacity in New Zealand, which is dedicated for conversion to gasoline, has been omitted.

EXHIBIT 3-3:

AVAILABILITY OF METHANOL TO THE U.S., BY COUNTRY

(Millions of Gallons Annually)

Region/Country	Supply Available	Nameplate Capacity	Supply Not Available*	Nameplate Capacity
NORTH AMERICA	X	2,623		
United States				
Canada				
Mexico				
EUROPE			1	1,053
Austria				
France				
Italy				
Netherlands				
Norway				
Spain				
Sweden				
United Kingdom				
West Germany				
LATIN AMERICA				
Argentina	X	261		
Bolivia			2	12
Brazil	X	45		
Chile	X	250		
Trinidad	X	230		
AFRICA				
Algera	X	36		
Libya			3	220
MIDDLE EAST	X	793		
Saudi Arabia				
Bahrain				
U.A. Emirates				
ASIA				
Burma	X	50		
Bangladesh			2	0
China	X	256		
India	X	50		
Korea			4	110
Malaysia	X	220		
Philippines			2	7
Taiwan	X	64		
OTHER PACIFIC				
Japan			1	177
Australia			2	0
New Zealand			5	625
Indonesia	X	114		
EASTERN BLOCK				
East Germany			3	200
U.S.S.R.			3	970
Yugoslovia			3	377
TOTAL		4,992		3,751

*Key: 1 = Net Import Region
2 = Capacity Insignificant
3 = Supply Unavailable to U.S. (for political reasons)
4 = Excess Supply Exported to Japan
5 = Supply Used for Conversion to Gasoline

- Insignificant capacity — several countries have extremely small methanol capacity. It is assumed that the bulk of this supply would be used locally.

- Supply unavailable to U.S. for political reasons — it has been concluded that several countries are unlikely to trade methanol with the U.S. These countries include Libya, East Germany, the U.S.S.R., and Yugosalovia.

- Supply used internally for conversion to gasoline — the majority of the capacity shown for New Zealand is for a plant which will directly convert methanol to gasoline. Output from this plant will therefore be unavailable to the U.S.

Except for the reasons stated above, production from each country has been assumed available to the United States. To develop the U.S. supply curve, it is necessary to adjust world supply for the supply that will not be available to the United States. As shown in Exhibit 3-3, the non-U.S. suppliers' total is 3.751 billion gallons. After adjusting for New Zealand's dedicated-to-gasoline production, the total is 3.1 billion. In Exhibit 3-4, total demand is adjusted to exclude the demand that will not compete with U.S. demand, by year. The adjusted demand is used to develop the supply curves, and represents a rough approximation of the expected demand components. Moreover, it is not possible to detail this demand adjustment by world regions, because the demand estimates by region are sketchy and conflicting (see Exhibit 3-2).

EXHIBIT 3-4:

WORLDWIDE METHANOL DEMAND SCENARIOS: ALL USES

(Millions of Gallons)

		Projected Worldwide Demand, Excluding U.S. Transportation Use		Worldwide Noncaptive Demand, Including U.S. Transportation Use			
Year	Total[1]	Demand Not Competing with U.S.[2]	Demand Competing with U.S. Demand	California Low Demand Case	California High Demand Case	National Low Demand Case	National High Demand Case
1990	5,700	2,500	3,200	3,200	3,220	3,200	3,350
1995	6,900	3,000	3,900	3,930	4,010	4,890	16,900
2000	8,400	3,200	4,700	4,830	4,950	8,950	31,700

[1] A four percent growth rate for chemical methanol demand is assumed. This is because the demand for chemical methanol has been observed to increase with GNP in developed countries.

[2] It is assumed that this quantity of demand will be satisfied by countries that do not supply the U.S. As shown in Exhibit 3-3, there is 3.751 billion gallons of nameplate capacity for non-U.S. suppliers of which 625 million gallons is dedicated for conversion to gasoline (New Zealand). The remaining 3.1 billion in capacity (and future additions to that capacity) is assumed to operate at about 80 percent utilization in supplying noncompeting methanol users. Thus, the number in the table is estimated based on an assessment of available capacity, not actual market demand.

Source: EEA and JFA estimates.

CHAPTER 4:

THE COST OF PRODUCTION FROM EXISTING CAPACITY

This chapter presents estimates of the cost of methanol production available to the United States by plants that are currently in operation, could be reopened, or are under construction. Because the methanol industry is characterized by significant excess capacity, methanol is now and will continue for some time to be available to the U.S. at less than fully costed prices. A major premise of this report is that the short-run price of methanol will be less than the lowest variable cost of the plants that are idle. This determination is based on the economic principle that governs periods of excess capacity: economic reasoning dictates that firms will produce methanol from existing plants (sunk capital) if the market price exceeds the average variable cost of production.

The methanol industry today is characterized by considerable excess capacity. Plants produce methanol or close down production based on the current and expected market price of methanol compared to the average variable costs of the individual production facility. If the market price of methanol exceeds variable costs and a market for the product is available, plants will operate because production is desirable so long as the plant does not sustain operating losses. Though plant owners would prefer to cover all costs of production (fixed and variable), losses are minimized as long as variable costs are covered. Prices received in excess of variable costs (contributions to fixed costs) are welcomed but not a prerequisite to the decision to produce for existing capital.

Throughout this report, reference is made to the variable, fixed and total costs of production. When comparing production costs to market prices, the correct comparison is average variable costs (or average total costs for new capacity) and market prices. For most types of production, average variable (or average total) costs vary with respect to output (capacity utilization) at the plant level. Thus, a unique average variable (or average total) cost is associated with each potential level of plant output. However, in this study, when average variable (total) costs were estimated, only one estimate was made: the average variable (total) cost of production at full (about 90%) operating capacity. No estimates were made for lesser (or greater) levels of output because no data were available to support these estimates and their omission was not considered limiting. Moreover, available evidence indicates that plant owners are more likely to run at full capacity for short periods of time (on a campaign basis) than less than full capacity for longer periods. Thus, throughout this report, the estimates and references to variable, fixed or total production costs represent the average (per unit of output) variable (fixed, total) cost of production at full capacity. These measures are appropriately compared to the market price per unit of output (gallon) of methanol.

Because firms (in this case existing methanol plants) will maximize profits (minimize losses) in the short run by producing when variable costs are covered, the identification of the variable cost of each producer leads to the development of the short-run industry supply curve. The short-run supply curve of the industry is, by definition, a composite of the average variable cost curves of each plant operating in the industry. As the product demand increases and approaches the potential level of supply from existing capacity, the price will increase and returns to capital for the highest cost producer may be achieved. At the point where entrepreneurs believe that new capacity can be expected to recover fixed and variable costs (and perhaps excess profits/economic rent), decisions to invest in additional capital (that may require higher market prices to cover fixed and variable costs when compared to existing capacity) will formulate the long-run supply curve. Long-run costs based on future capacity are discussed in Chapter 6. It should be remembered in all cases that spot prices may fall below variable costs or above total costs, due to short-term market imperfections.

The following sections discuss the fixed, variable and total costs of production from existing capacity and their relationship to the short run industry supply curve.

FIXED COSTS

Fixed costs are, by definition, the costs that are incurred by the owners of existing plants even if the plant is closed. These costs include basic levels of maintenance and overhead that are necessary to keep the plant from depreciating more rapidly than it would if operating. Perhaps more important to methanol plant owners, fixed costs include recovery of and a return on investment from the sunk capital that was required to build the plant. Fixed costs are of great concern to owners because these costs represent the maximum loss that will be sustained in the event that the plant is not operated at all. If the market prospects offer no hope to owners, the burden of fixed costs will be unacceptable. The only way to stop the on-going loss of fixed costs is to abandon the plant entirely which has the effect of consolidating the future stream of fixed-cost losses into a lump-sum loss. Unfortunately for the owners of methanol plants, the excess supply conditions in the present marketplace dictate that owners are the only ones concerned with fixed costs. As long as excess capacity is available, the market price will squeeze existing plants so that, for a given level of supply, the price will not exceed the variable costs of the lowest variable cost plant in idle condition. For those operating, the returns to fixed costs are expected to be less than or equal to the difference between the variable cost of their plant and the lowest variable cost plant not operating.

While distressing for plant owners, the limited return on fixed costs is representative of a young industry that has grown in capacity more quickly than demand conditions warrant. Indeed, if the market for methanol increases dramatically because of transportation (or other) uses, existing plant owners will shift from minimizing losses to maximizing profits and may receive economic rent, in addition to a return of variable and fixed costs. Until then, however, economic theory dictates that the supply curve (and associated market prices) will be predicated on the variable costs of the individual producers.

The fixed costs associated with methanol plants are very plant-specific. Fixed costs depend on the age of the plant, the costs of building the plant, the financing costs incurred to build the plant, the opportunity cost of the funds used to build the plant, the location of the plant and so on. Secondary sources do not provide this level of plant-specific information for most U.S. plants: estimates of fixed costs for foreign plants would be highly speculative and based on limited anecdotal information. However, since the fixed costs of existing plants do not affect the short-run industry supply curve, this lack of data on fixed costs does not hinder the development of the short-run industry supply curve or estimates of delivered prices. Fixed costs do become very important, however, when the supply curve moves from the short-run to the long-run. As explained in Chapter 6, the fixed costs associated with future (long run) capacity play a very important part in the long-run supply curve for the methanol industry.

VARIABLE COSTS

The variable costs of methanol production were estimated based on available estimates of methanol production costs. First, variable costs were divided into their major components. For each component, an average unit cost (baseline) was estimated based on available information for U.S. plants. A 113.5 million gallon per year plant was selected as the baseline size. The impact of factors such as location, size of plant, type of feedstock, and production process were each researched and estimated to reflect the individual production costs of each methanol plant that was identified as a potential U.S. supplier. The plant-specific costs of production were used to estimate a weighted average unit cost by country of production.

The cost categories for production estimates are (1) feedstock, (2) maintenance, (3) catalyst, (4) utility, (5) labor, and (6) other costs. The costs are discussed according to relative size for most plants, with feedstock and maintenance representing the largest cost share. Because data were not available to distinguish between fixed and variable costs within the identified categories, all fixed costs that are incurred during plant operation, except those related to capital, are included in the estimates. Thus, estimates include taxes, insurance, and maintenance costs that may actually be fixed costs in addition to costs that are clearly variable costs, e.g., feedstock costs. Therefore, the estimates of "variable" costs presented in this report represents an overstatement (believed to be relatively small) of the actual variable costs (some fixed costs are included). Moreover, the largest factor of fixed costs, those representing capital recovery and charges, are excluded from the variable cost estimates. Without extensive additional research it cannot be determined precisely how much the variable costs presented in this chapter are overstated due to the inclusion of fixed costs. The overstatement is, however, believed to be small and not have a significant impact on estimates of production cost.

Feedstock Costs

A major problem in estimating production prices for methanol is the identification of the cost of natural gas for individual plants. In the U.S., natural gas prices for broad categories of users are available from published sources. However, in many developing countries natural gas prices are difficult to estimate. These countries often build methanol plants because they have little or no alternate uses for the natural gas. In countries where natural gas is transacted, there are often no data available on selling prices. Furthermore, gas supplies are frequently co-products or by-products with crude oil production. In some countries the gas is vented, flared, or fed back into the ground for repressuring indicating little or no opportunity cost. In addition, feedstock costs are highly site specific depending on transportation distance and difficulty as well as the available collection infrastructure. The difficulty associated with valuing natural gas was reflected in Alcohol Week in an article that discussed the cost of methanol production from the Trinidad plant. One source contacted by Alcohol Week stated that natural gas costs were $0.50 per million Btu. A second source estimated natural gas costs for this plant to be more like $1.00 per million Btu.[1]

Natural gas feedstock costs in cents per gallon for countries assumed to be potential U.S. suppliers are presented in Exhibit 4-1. These costs are based on natural gas values developed by DeWitt & Company, a major methanol marketing advisor and consultant.[2] These estimates reflect the value of the gas and costs for collecting and transporting the gas to the methanol plant. Where estimates for specific countries were not available they were estimated based on countries with similar locations, gas resources, and production and consumption profiles.[3] For the most part, with the exception of the U.S. and Canada, the natural gas value is assumed to be zero. Obviously, more research on the individual natural gas market is required to develop site-specific input cost that will reflect current opportunities as well as the changes in the market that will occur as transportation use of methanol increases world-wide.

Feedstocks other than natural gas are also used in the production of methanol. However, for the countries assumed to be potential U.S. suppliers there are only two plants that use alternative feedstocks. Both of these plants are located in the U.S. One of these plants is the Eastman Chemical Co. plant in Kingsport, Tennessee. This plant uses a coal feedstock and a Lurgi low pressure process. The capacity of the plant is approximately 60 million gallons per year. Feedstock costs for this plant were based on cost data for a Lurgi low pressure coal-to-methanol plant indicating total coal costs of $107.5 million for a 242 million gallon per year plant or 44.42 cents per gallon.[4]

The second plant is the Du Pont plant in Deer Park, Texas. This plant uses a heavy liquids feedstock and a Lurgi low pressure process. Plant capacity is approximately 200 to 250 million gallons per year. Feedstock costs for this plant were based on illustrative economic comparisons of methanol production from various raw materials in the form of an index of feedstock and fuel energy requirements. The index for a gas-based methanol plant is 100 while the index for a residual oil-based methanol plant is 120 and upwards.[5] The minimum factor of 120 percent was applied to the adjusted natural gas cost of 22.24 cents per gallon to arrive at a feedstock cost for this plant of 26.69 cents per gallon.

EXHIBIT 4-1:

FEEDSTOCK COSTS PER GALLON

FOR POTENTIAL U.S. SUPPLIERS, BY COUNTRY

($, 1985)

Country	Dollars Per Million Btu[1]	Cents[5] Per Gallon
U.S.	2.50	23.50
Canada	1.50	13.34
Mexico	0.50	4.45
Argentina	0.25	2.22
Brazil	0.50 [2]	4.45
Chile	0.50 [2]	4.45
Trinidad	0.50	4.45
Algeria	0.50 [3]	4.45
Bahrain	0.50 [3]	4.45
Saudi Arabia	0.50	4.45
Arab Emirates	0.50 [3]	4.45
Burma	1.00 [4]	8.90
China	1.00 [4]	8.90
India	1.00 [4]	8.90
Malaysia	1.00	8.90
Taiwan	1.00 [4]	8.90

[1] Data from R.G. Dodge, "Competitive Methanol Production Economics," presented to the 1985 World Methanol Conference, Amsterdam, The Netherlands, December 9-11, 1985.

[2] Price for Brazil and Chile are imputed based on price for Trinidad.

[3] Price for Algeria, Bahrain, and the United Arab Emirates are imputed based on price for Saudi Arabia.

[4] Price for Burma, China, India, and Taiwan are imputed based on price for Malaysia.

[5] Gas use was converted from dollars per million Btu to cents per gallon using a factor of 0.1124 million Btu per gallon. This factor was derived based on an estimate of gas use of 13,500 Btu per pound of methanol (World Bank, Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries, April 1982, p.42) and 6.59 pounds of methanol per gallon (Arthur M. Brownstein, U.S. Petrochemicals, The Petroleum Publishing Company, Tulsa, Oklahoma, 1972, p.81.). For a comparable factor of 0.1139 million Btu per gallon in the U.S. for 1982 see The Outlook for Natural Gas Use in Methanol and Ammonia Production in the U.S., prepared for the American Gas Association by Chem Systems Inc., March 1983, p.28.

Maintenance Costs

Methanol plants require periodic shutdowns for maintenance as well as unscheduled shutdowns for mechanical or catalyst problems. The costs associated with maintenance are developed separately from manufacturing labor costs because this periodic maintenance is generally performed by independent contractors, especially in areas where chemical plants and refineries are concentrated. This is because plant "turnarounds" by maintenance contractors have many advantages, including lower year-round staff costs for the plant operator.[6]

Maintenance costs are generally given in the literature as a percent of fixed capital.[7] Therefore, it is assumed that these costs, in total, will increase with the plant size, but will drop on a per unit (output) basis. As a result of this approach, maintenance costs are assumed to be higher in developing countries where capital costs are generally higher.

Maintenance costs may also vary depending on capacity utilization of the plant. However, it is uncertain as to the extent or direction of this change. For example, if the plant is running at low utilization or on a campaign basis there may be different maintenance requirements. In addition, there is evidence that catalysts wear down if not used periodically. This may cause per unit costs for the maintenance associated with catalyst replacement to rise as capacity utilization falls. Since data on the maintenance costs for idle plants (a fixed cost) or less than fully-operating plants are not available, it is assumed per unit maintenance costs do not vary with capacity utilization.

Two sources were used to estimate the cost of maintenance for the baseline plant, a 113.5 million gallon U.S. natural gas plant. The World Bank report indicates that maintenance will cost 2.5 percent of fixed capital for a plant in a developed site in an industrialized country.[8] Fixed capital for this plant is estimated as $98.5 million (for a 113.5 million gallon per year plant). Maintenance is therefore $2.46 million per year or 2.17 cents per gallon. The Chem Systems report estimates that maintenance, material and labor will cost 5.0 percent of capital costs inside battery limits, estimated at $70.2 million for a 113.5 million gallon per year plant.[9] Maintenance is therefore $3.51 million per year or approximately 3.09 cents per gallon according to this source. Although this category includes labor it appears to refer only to the labor associated with maintenance because normal operating labor costs are given separately. The average of the two available baseline maintenance cost estimates is 2.63 cents. Because these sources report data for the 1980-1983 time period the estimate 3.0 cents per gallon (1986 $) was used for the baseline.

For the two U.S. plants that use alternative feedstocks, costs can be expected to differ. The Jet Propulsion Laboratory report estimates maintenance costs of $26.3 million for 242 million gallons per year of methanol production from a dry bottom Lurgi coal-to-methanol plant, or 10.9 cents per gallon.[10] This estimate was used for the Eastman Chemical Plant. No data were available to estimate the maintenance cost for the heavy oil (Deer Park) U.S. plant. Thus, maintenance costs (per unit) for this plant were assumed to equal a natural gas plant (3.0 cents per gallon).

To estimate the effect of location (developed versus undeveloped country), World Bank estimates of the influence of location based on a fixed percentage of capital costs were utilized. The World Bank estimates that capital costs in developing countries can be 30 percent, 60 percent or 100 percent above the industrialized country reference case, depending on a number of factors including available infrastructure, site development, remoteness and the need for expatriate project management.

The assumption used for this study is that industrialized countries pay the baseline estimated cost for maintenance. For extremely undeveloped countries, a 60 percent markup (over baseline) was assumed. For developing countries or countries that have a substantial oil industry a 30 percent markup (over baseline) was used.

Maintenance costs will also vary by size of plant. To estimate the effect of capacity on maintenance costs data from two sources were used. For plants over 80 million gallons per year, estimates from the World Bank were used. The World Bank reports maintenance costs for 1000 tons per day and 2000 tons per day plants. These costs are based on 2.5 percent of fixed capital or $2.46 million and $4.0 million. Assuming a linear relationship, this results in a change of $36 in maintenance costs per million gallon change in capacity. For plants under 80 million gallons per year, estimates were taken from U.S. Petrochemicals.[11] This source shows the total of maintenance and labor costs of 0.89 cents per gallon for a 80 million gallon per year plant and 2.50 cents per gallon for a 15.0 million gallon plant. Again, assuming a linear relationship, this results in a change of $248 per million gallon change in capacity. (For this study it was assumed that the mix of labor and maintenance is constant for plants smaller than 80 million gallons.)

Exhibit 4-2 provides estimates of maintenance costs for each country assumed to be a potential supplier to the U.S. utilizing the baseline estimate of 3.0 cents per gallon and adjusting feedstock, location, and capacity factors as discussed above.

Catalyst Costs

Methanol is produced by bringing a synthesis gas, composed of carbon monoxide and hydrogen, into contact with a catalyst in the presence of heat and pressure. The two leading methanol processes, the ICI and the Lurgi processes, have many similarities, but use different proprietary catalysts and have somewhat different configurations regarding the way the synthesis gas is fed over the catalyst.[12] One efficient methanol converter design is a vessel containing copper-based catalyst-filled tubes surrounded by boiler feed water.[13]

In a well-operated methanol plant both the reforming and synthesis catalysts will usually last from four to five years before their activity falls below acceptable levels.[14] In methanol plants catalyst activity must be carefully monitored to keep track of any loss in effectiveness.

There are three sources that provide separate estimates of the cost for catalysts in a natural gas-to-methanol plant. The World Bank estimates that "Catalysts and Supplies" will cost 1.5 cents per gallon.[15] The Chem Systems report estimates that "Catalysts & Chemicals" will cost $750,000 on an annual basis for a 113.5 million gallon per year or 0.66 cents per gallon.[16] The Dodge paper estimates that "Catalysts and Chemicals" cost approximately 0.88 cents per gallon.[17] Moreover, estimates show little (JPL - Texaco Coal Gasification) or no (World Bank and Dodge) variation across plant sizes or location. Catalyst costs are therefore estimates to be 1.0 cents per gallon. No variation in these costs across loaction or plant size is assumed.

For alternate stocks a JPL estimate of 1.16 cents per gallon, based on a 242 million gallon/year dry bottom Lurgi, was used for the coal-to-methanol plant. Lacking a better estimate, the catalyst cost for the "heavy liquids" plant was estimated to be the same as for a natural gas based plant.

Utility Costs

Utility costs by country are shown in Exhibit 4-3, and were developed from the Dodge paper presented at the 1985 World Methanol Conference.[18] Utility costs include

EXHIBIT 4-2:

MAINTENANCE COSTS PER GALLON

FOR POTENTIAL U.S. SUPPLIERS, BY COUNTRY

($, 1985)

Country	Country Status and Maintenance Markup	Cents Per Gallon
U.S.	Developed (1.0)	3.04
Canada	Developed (1.0)	2.62
Mexico	Developing/Refining (1.3)	4.80
Argentina	Developing (1.6)	4.80
Brazil	Developing (1.6)	6.38
Chile	Developing (1.6)	4.01
Trinidad	Developing (1.6)	4.78
Algeria	Developing/Refining (1.3)	5.48
Bahrain	Developing/Refining (1.3)	3.92
Saudi Arabia	Developing/Refining (1.3)	3.45
Arab Emirates	Developing/Refining (1.3)	3.18
Burma	Developing (1.6)	6.18
China	Developing (1.6)	5.06
India	Developing (1.6)	7.14
Malaysia	Developing (1.6)	4.82
Taiwan	Semi-Developed (1.3)	4.57

Source: JFA estimates.

Note: Value shown in parenthesis indicate the markup applied (U.S. costs = 1.0) to the estimated operating costs for similar plants located in the U.S.

EXHIBIT 4-3: UTILITY COSTS PER GALLON FOR POTENTIAL U.S. SUPPLIERS, BY COUNTRY

($, 1985)

Country	Dollars Per Metric Ton[1] Power	Cooling Water	Makeup Water	Total	Cents[2] Per Gallon
U.S.	0.3	4.4	0.2	4.9	1.46
Canada	0.2	2.8	0.1	3.1	0.93
Mexico					1.46[3]
Argentina	0.1	1.4	0.1	1.6	0.48
Brazil					0.48[4]
Chile					0.48[4]
Trinidad	0.1	1.6	0.1	1.8	0.54
Algeria					0.87[5]
Bahrain					0.87[5]
Saudi Arabia	0.1	2.7	0.1	2.9	0.87
Arab Emirates					0.87[5]
Burma					1.17[6]
China					1.17[6]
India					1.17[6]
Malaysia	1.6	2.2	0.1	3.9	1.17
Taiwan					1.17[6]

[1] Data from R.G. Dodge, "Competitive Methanol Production Economics," presented to the 1985 World Methanol Conference, Amsterdam, The Netherlands, December 9-11, 1985.

[2] Data are converted from metric tons to gallons using a factor of 334.5 gallons per metric ton. This is based on 2204.6 pounds per metric ton and 6.59 pounds per gallon. The factor of 6.59 pounds per gallon is from Arthur M. Brownstein, U.S. Petrochemicals, The Petroleum Publishing Company, Tulsa, Oklahoma, 1972.

[3] Costs for Mexico are imputed based on costs for the U.S.

[4] Costs for Brazil and Chile are imputed based on costs for Argentina.

[5] Costs for Algeria, Bahrain, and the United Arab Emirates are imputed based on costs for Saudi Arabia.

[6] Costs for Burma, China, India, and Taiwan are imputed based on costs for Malaysia.

charges for power, cooling water, and makeup water. Where estimates for specific countries were not available, they were imputed based on countries with similar locations and/or similar economic characteristics.

Labor Costs

A modern methanol plant is a highly instrumented and automated facility. Labor costs are generally low, as the typical plant will employ a small number of workers to monitor technical apparatus and perform other duties on a daily basis. Methanol plants also require labor during periodic shutdowns for maintenance, as well as unscheduled shutdowns where unexpected mechanical or catalyst problems have developed. Labor dedicated to maintenance activity is estimated separately as part of maintenance costs.

Full-time labor associated with a methanol plant operation has been categorized by the Chem Systems report to include supervisors, foremen, and laborers.[19] The Chem Systems report provides estimates of the number of employees and applicable salary for each position. Data are provided for a 113.5 million gallon plant in 1980. Included is one supervisory position at $32,700 per year, 5 foremen at $27,100 per year, and 23 laborers at $23,900 per year for a total of $719,000 (.63 cents per gallon). Estimates for the plant labor are based on one foreman and five laborers per shift. Several other sources provide labor cost data either on a per unit basis or as a percent of capital (2,4,6). Comparisons are difficult because somewhat different definitions are used in each source. In general, labor costs as estimated in the various available sources in various year dollars and under a variety of assumptions in the range of 0.63 to 1.5 cents per gallon. For the purpose of this study we have made the conservative assumption that labor costs are 1.5 cents per gallon in 1985 dollars for a 113.5 million gallon per year plant located in the U.S. The small differences in other published labor cost estimates will have little impact on the total production costs.

In many production processes capacity utilization would have a large impact on labor costs per unit of output. However, methanol manufacturers are generally unwilling to run plants below full capacity, and when forced to do so, will operate the unit on short bursts. Furthermore, since the labor pool is small, it is relatively easy to lay off or furlough workers during slack operating periods. Therefore, labor costs per unit of output do not vary considerably with capacity utilization and thus, no adjustment was made for capacity utilization.

The production process used may also alter labor requirements for methanol production, however, as most plants currently utilize one of the two low pressure processes (ICI and Lurgi) the production process is not particularly important. A comparison of labor costs for coal versus natural gas are provided by SRI International.[20] Estimates of labor required for a bituminus coal plant labor costs are 3.8 cents per gallon. This estimate was used for the one identified coal-based methanol plant.

Perhaps the most important factor affecting labor costs is location. The World Bank has estimated labor costs for various site and country locations.[21] For a developed or developing site in a developing country labor costs are estimated to be about 50 percent less than the labor costs in an industrialized country. For a remote or undeveloped location in a developing country, labor costs are estimated to be 75 percent of the labor costs in the industrialized country case. Labor costs are assumed to be higher in the remote site/developing country than the developed site/developing country due to the possible need for expatriate assistance. The Bureau of Labor Statistics (BLS) collects data on hourly costs for production workers for various industries and countries.[22] These data demonstrate a much larger labor differential than those calculated by the World Bank, and indicate that the 50 percent factor applied to developing countries by the World Bank would be more applicable to developed countries other than the U.S. A factor of approximately 25 percent seems appropriate for developing countries. It should be noted that the BLS data are for production workers only. The Chem Systems report indicates that approximately 75 percent of labor costs are for production workers.[23] Thus, labor cost differentials for this analysis were calculated based on the BLS index for 75 percent of costs (i.e., that attributable to laborers), while the remaining 25 percent of costs (i.e., that attributable to foremen and supervisory labor) were assumed to be at U.S. costs. Countries for which data from BLS were not available were estimated based on nearby countries or countries with similar GDP per capita. The resulting labor cost indexes are shown in Exhibit 4-4.

The final factor effecting labor cost is the size of the plant or plant capacity. To estimate the effect of capacity on labor costs data from two sources was used. For plants over 80 million gallons per year estimates from the World Bank were used. The World Bank reports labor costs for 1000 tons per day (113.5 million gallons per year) and 2000 tons per day (277 million gallons per year) plants.[24] Assuming a linear relationship, these estimates indicate a change of $47 per million gallons of additional capacity. For smaller plants, the rate of change was estimated from U.S. Petrochemicals. This source shows the total of labor and maintenance costs increasing

LABOR COST DIFFERENTIAL INDEXES

			Labor Cost Index[1]	Labor Cost Index Adjusted for Supervisory[2]
North America	—	United States	100	100
		Canada	82	87
		Mexico	14	36
South America	—	Argentina (Brazil)	10	33
		Brazil	10	33
		Chile (Brazil)	10	33
		Trinidad (Singapore)	19	39
Africa	—	Algeria (Portugal)	12	34
		Libya (Israel)	37	53
Asia	—	Bahrain (Isreal)	37	53
		Bangladesh (India)	4	28
		Burma (India)	4	28
		China (India)	4	28
		India	4	28
		Indonesia (Korea, India)	8	31
		Japan	51	63
		Korea	11	33
		Malaysia (India)	4	28
		Saudi Arabia (Isreal)	37	53
		Taiwan	13	35
		United Arab Emirates (Isreal)	37	53
Europe	—	Austria	51	63
		East Germany (W. Germany)	74	81
		France	59	69
		Italy	59	69
		Netherlands	68	76
		Spain	37	53
		Sweden	74	81
		United Kingdom	46	60
		USSR (Port)	12	34
		West Germany	74	81
		Yugosolovia (Port)	12	34
Australia and Oceana	—	Austrailia	74	81
		New Zealand	33	50

Source: JFA estimates.

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[1] BLS

[2] BLS and World Bank using Jack Faucett Associate's methodology.

the rate of $25 per million gallons in capacity for plants smaller than 80 million gallons per year. For this study it was assumed that the mix of labor and maintenance is constant for plants smaller than 80 million gallons.

Exhibit 4-5 provides estimates of labor cost for each country assumed to be a potential U.S. supplier based on the estimate of 1.5 cents per gallon for a 1000 ton (113.5 million gallon) U.S. plant and the production process, feedstock, location, and plant size factor adjustments developed above.

Other Costs

Other costs include insurance, general and administrative, selling costs and overhead costs. While available estimates do not distinguish between fixed and variable costs, fixed costs are assumed to be small. Tenneco estimates "selling & administrative" cost to be 3.0 cents per gallon for plants in the U.S. Gulf and Western Europe, and 4.2 cents per gallon in remote areas.[25] The Chem Systems report provides separate estimates for direct overhead ($323 thousand), general plant overhead ($2748 thousand), and insurance and property taxes ($1,420 thousand), for a total of $4491 thousand. These figures are for a 113.5 million gallon plant and convert to 4.0 cents per gallon. The World Bank also provides separate estimates for several categories of "other" costs. These include $1.4 million for overhead, $1.1 million (3% of sales) for general, administrative and marketing, and $1.0 million (1% of fixed capital) for insurance and other for a total of $3.5 million. These estimates are also for a 113.5 million gallon plant and convert to 3.1 cents per gallon. In all cases, the estimates do not change by plant size.

A baseline estimate of 3.4 cents per gallon for these costs was based on the average of the estimates from Tenneco (3.0 cents per gallon), Chem Systems (4.0 cents per gallon), and World Bank (3.1 cents per gallon). For developing countries the Simmons (Tenneco) estimate of 4.2 cents per gallon was used.

The Sum of Variable Costs

The variable production costs of each country identified as a potential supplier to the U.S. are shown in Exhibit 4-6. The delivered U.S. cost is based on the average variable

EXHIBIT 4-5:

LABOR COSTS PER GALLON FOR POTENTIAL U.S. SUPPLIERS, BY COUNTRY

($, 1985)

Country	Cents Per Gallon
U.S.	1.30
Canada	0.88
Mexico	0.80
Argentina	0.47
Brazil	0.83
Chile	0.28
Trinidad	0.58
Algeria	0.93
Bahrain	0.80
Saudi Arabia	0.56
Arab Emirates	0.42
Burma	0.67
China	0.46
India	0.84
Malaysia	0.42
Taiwan	0.72

Source: JFA estimates.

EXHIBIT 4-6

SUMMARY OF AVERAGE VARIABLE COSTS OF METHANOL PRODUCTION, BY COUNTRY

(Cents Per Gallon, 1986 $)

Country	Feedstock	Catalyst	Labor	Maintenance	Utility	Other	TOTAL
U.S.	23.50	1.00	1.30	3.04	1.46	3.37	33.67
Canada	13.34	1.00	0.88	2.62	0.93	3.37	22.14
Mexico	4.45	1.00	0.80	4.80	1.46	3.37	15.88
Argentina	2.22	1.00	0.47	4.80	0.48	4.20	13.17
Brazil	4.45	1.00	0.83	6.38	0.48	4.20	17.34
Chile	4.45	1.00	0.28	4.01	0.48	4.20	14.42
Trinidad	4.45	1.00	0.58	4.78	0.54	4.20	15.55
Algeria	4.45	1.00	0.93	5.48	0.87	4.20	16.93
Bahrain	4.45	1.00	0.80	3.92	0.87	4.20	15.24
Saudi Arabia	4.45	1.00	0.56	3.45	0.87	4.20	14.53
Arab Emirates	4.45	1.00	0.42	3.18	0.87	4.20	14.12
Burma	8.90	1.00	0.67	6.18	1.17	4.20	22.12
China	8.90	1.00	0.46	5.06	1.17	4.20	20.79
India	8.90	1.00	0.84	7.14	1.17	4.20	23.25
Malaysia	8.90	1.00	0.42	4.82	1.17	4.20	20.51
Taiwan	8.90	1.00	0.72	4.57	1.17	4.20	20.56

Source: JFA estimates.

production costs plus transportation costs as discussed in Chapter 5. Moreover, the variable production costs are based on the weighted average production costs by country and thus implicitly assumes that a country will supply methanol based on the weighted average production costs of plants within the country.

Again, the reader is reminded that the costs shown in Exhibit 4-6 are presented as variable costs but do include a small amount of fixed costs, e.g., undistinguished fixed overhead, insurance, and maintenance costs. The total of these fixed costs that are included in the variable costs, however, are not believed to exceed the margin of error on these estimates and thus do not significantly distort the findings.

TOTAL COSTS

In economic terms, the total cost of production is the sum of the fixed and variable costs with fixed cost defined to include an economic return on the investment. As discussed previously, in the current methanol market variable costs are most important because with the excess supply (capacity) conditions, producers make decisions based on variable costs. Thus, to predict short-run supply, variable costs must be estimated.

The secondary sources available to estimate production costs limit the procedure. Fixed costs are not available per se, though some fixed costs are included in available estimates of production costs. The data inadequacies thus prevent accurate estimates of total costs and limit the accuracy of the estimates presented for variable costs. Basically, the variable cost estimates presented in the previous section include some fixed costs, but these costs (particularly on a per-gallon basis) are small.

This research effort did not include the additional research that would be required to quantify fixed costs. Moreover, the cost of capital and profit for existing plants that are the primary components of fixed cost were not estimated. The estimation of these elements would require detailed and plant-specific information that is not generally available. However, the absence of estimates of fixed costs of existing capacity is not considered limiting because (1) in the short-run, prices will be established based on variable costs (due to conditions of excess capacity) and (2) in the long-run, prices will be influenced by the total costs of additional (future) capacity, rather than the total costs of existing capacity. Thus, while estimates of total costs of existing capacity would be informative, their primary value is limited to identifying the producer surplus that may be earned by plant owners as the market place shifts from the short-run (excess capacity conditions) to the long-run where the cost of future additional capacity will dictate the prices paid to methanol producers.

CHAPTER 4 FOOTNOTES

1. Alcohol Week, issue date, p.4.

2. R.G. Dodge, "Competitive Methanol Production Economics," presented to the 1985 World Methanol Conference, Amsterdam, The Netherlands, December 9-11, 1985.

3. Data used for this purpose include the Energy Information Administration's International Energy Annual, 1984, DOE/EIA-0219(84), pp. 63-70, 80, and World Bank, Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries. April 1982, p.60.

4. Jet Propulsion Laboratory, California Methanol Assessment, Volume II: Technical Report, pp. 4-9, 4-10.

5. World Bank, Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries, April 1982, p.39.

6. U.S. Department of Commerce, A Competitive Assessment of the U.S. Methanol Industry," May 1985, p.6.

7. World Bank, p.42, and Chem Systems, Inc., The Outlook for Natural Gas Use in Methanol and Ammonia Production in the U.S., Prepared for the American Gas Association, Mary 1983, p.26.

8. World Bank, p.42.

9. Chem Systems, Inc., p.26.

10. Jet Propulsion Laboratory, pp. 4-9, 4-10.

11. Arthur M. Brownstein, U.S. Petrochemicals, The Petroleum Publishing Co., Tulsa, Oklahoma, 1972, p.84.

12. U.S. Department of Commerce, p.3.

13 World Bank, p. 36.

14. For example, in the ICI process conversion of carbon oxides per pass is normally 40 to 60 percent. Loss of effectiveness is shown in reductions in conversions per pass.

15. World Bank, p.42

16. Chem Systems, Inc., p.26

17. R. G. Dodge.

18. R. G. Dodge.

19. Chem Systems, Inc., p.26.

20. SRI International, Chemical Economics Handbook, October 1983.

21. World Bank, p.42.

22. U.S. Department of Labor, Bureau of Labor Statistics, unpublished computer printouts.

23. Chem Systems, p.26.

24. World Bank, p.42. Note: tons per day are converted to gallons per year based on 334.5 gallons per metric ton and 330 days of expected operation.

25. Tenneco, "Methanol, World Supply/Demand Outlook," a paper presented by R. E. Simmons at the 1985 National Conference on Alcohol Fuels, p.18.

CHAPTER 5:

THE COST OF DELIVERY

The production costs of foreign producers, as estimated in Chapter 4, range from 12 to 30.3 cents per gallon compared to a U.S. cost estimate of 33.4 cents per gallon. However, the cost of shipping the product from these countries to the U.S. is high and can run as much as 18 cents per gallon. The per gallon cost of production from existing plants is shown along with delivered prices in Exhibit 5-1. For some foreign producers, the added transportation costs to U.S. markets more than double the plant gate product cost. For this reason, it is important to understand the currently available transportation options as well as future alternatives that may reduce the cost of delivery to the U.S.

High transportation costs are a major concern to policy makers. Since there are already a number of potential suppliers for a U.S. methanol-for-transportation market that produce at quite low cost, the primary avenue for reducing delivered U.S. prices is by reducing transportation costs. However, transportation economies of scale that would permit lower transportation costs (and thus lower the delivered U.S. price) are only achievable in higher demand scenario than currently exists.

The estimates shown in Exhibit 5-1 represent the total cost of delivering product from the country identified to the U.S. location by traditional means in quantities up to about one billion gallons of U.S. demand for methanol. Because shipping costs are priced based on total costs from origin to destination, separate estimates of ocean transport, overland haulage, inland waterway costs or loading charges are not included. The costs shown represent rough estimates based on available literature and opinions of shipping experts. Actual rates paid will depend on a variety of factors, including volume shipped, loading/unloading requirements, availability of vessels, types of long-term agreements and so on.

Economies of scale associated with large volumes such as those that are achieved by crude oil shipments would considerably lower the transportation costs presented in Exhibit 5.1.[1] However, these scale economies require the use of the largest vessels

EXHIBIT 5-1:

DELIVERED COST OF METHANOL AT LOW LEVELS OF DEMAND[1] FROM CURRENT PRODUCERS TO U.S. DESTINATIONS, BY COUNTRY

(Cents per gallon, 1986 $)

Country	Average Variable Cost	TRANSPORTATION CHARGES: California	TRANSPORTATION CHARGES: Gulf of Mexico	TRANSPORTATION CHARGES: Northeast	TRANSPORTATION CHARGES: Greak Lakes	TOTAL DELIVERED U.S. PRICE: California	TOTAL DELIVERED U.S. PRICE: Gulf of Mexico	TOTAL DELIVERED U.S. PRICE: Northeast	TOTAL DELIVERED U.S. PRICE: Great Lakes
U.S.	33.67	2.0	—	2.0	3.0	35.67	33.67	35.67	36.67
Canada	22.14	2.0	4.0	4.0	2.0	24.14	26.14	26.14	24.14
Mexico	15.88	3.0	2.0	3.0	5.0	18.88	17.88	18.88	20.88
Argentina	13.17	13.0	11.0	11.0	13.0	26.17	24.17	24.17	26.17
Brazil	17.34	11.0	9.0	9.0	11.0	28.34	26.34	26.34	28.34
Chile	14.42	12.0	10.0	11.0	13.0	26.42	24.42	25.42	27.32
Trinidad	15.55	10.0	8.0	8.0	10.0	25.55	23.55	23.55	25.55
Algeria	16.93	18.0	16.0	16.0	18.0	34.93	32.93	32.93	34.93
Bahrain	15.24	18.0	16.0	16.0	18.0	33.24	31.24	31.24	33.24
Saudi Arabia	14.53	18.0	16.0	16.0	18.0	32.53	30.53	30.53	32.53
Arab Emirates	14.12	18.0	16.0	16.0	18.0	32.12	30.12	30.12	32.12
Burma	22.12	10.0	12.0	13.0	15.0	32.12	34.12	35.12	37.12
China	20.79	10.0	12.0	13.0	15.0	30.79	32.79	33.79	35.79
India	23.25	11.0	13.0	14.0	16.0	34.25	36.25	37.25	39.25
Malaysia	20.51	10.0	12.0	13.0	15.0	30.51	32.51	33.51	35.51
Taiwan	20.56	10.0	12.0	13.0	15.0	30.56	32.56	33.56	35.56

Source: JFA estimates based on information contained in Competitive Methanol Production Economics, R.G. Dodge, Dewitt & Co., and discussions with shippers and freight forwarders.

[1] U.S. demand of up to one billion gallons per year.

currently moving crude oil: 200,000-300,000 plus dead weight ton (dwt) vessels. A 200,000 dwt tanker holds about 68 million gallons of methanol.[2] Since, in the California high demand scenario, only 252.3 million gallons of methanol per year would be required, use of a 200,000 dwt tanker would imply less than four shipments per year. Because demand in California would utilize at least two terminals, the large carriers could only be used if the two terminals received a total of four shipments per year, combined. This is untenable. Moreover, the estimates of distribution system requirements developed by EEA[3] include storage requirements of only 500,000 barrels or 21 million gallons (8.3 percent of annual demand) for methanol in a demand scenario of 250 million gallons per year.

A 21 million gallons per year storage capacity would allow receipt from no larger than a 50,000 dwt tanker that would deliver 15 times per year. Thus, at the highest point of consumption in the California scenario, it might be feasible to have a relatively small (50,000 dwt) tanker "dedicated" to methanol movement. Whether even this level of economy could be achieved depends on a number of variables, including:

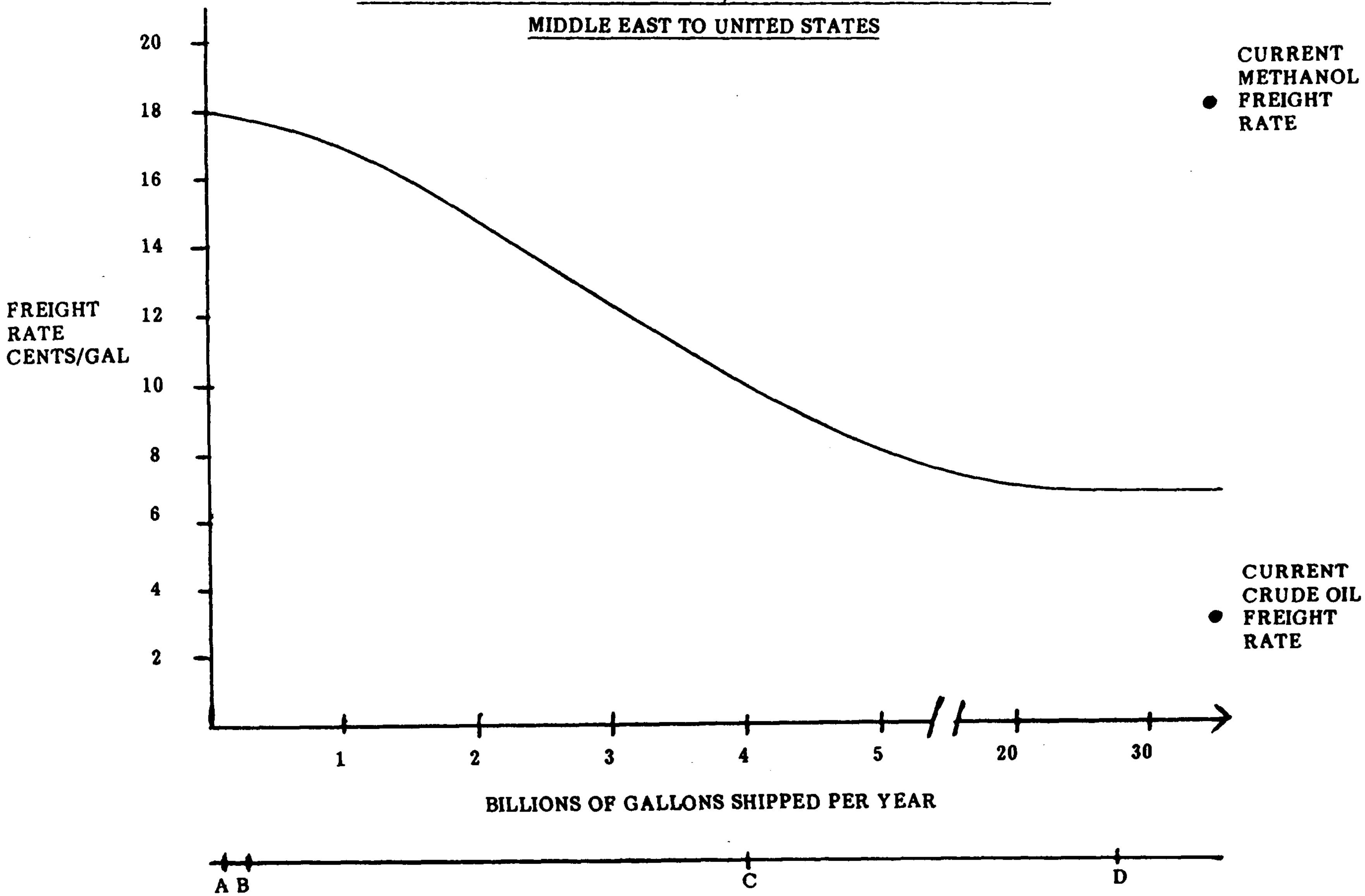
- The availability and cost of 50,000 dwt vessels;
- the ability to economically schedule a single vessel for routes that could include producers geographically distant; and
- the availability of backhaul shipments to reduce the cost of the otherwise empty movements from California to methanol producers or added shipments of other types to fully utilize the tanker.

Given the constraints that would be encountered in economically utilizing a 50,000 dwt tanker (that was very cost-effective in the 1950's but now does not compare to the economies of scale achieved by the large 200,000 to 300,000 dwt plus carriers), few if any economies of scale in transportation can be expected in the California scenario (the highest level of demand in the California scenarios is 250 million gallons per year).

The national scenario offers greater potential for economies of scale in transportation, especially in the high demand case. For example, in the year 2000 at the low demand estimate of 4,252 million gallons per year, the U.S. (as a whole) could accept about 42 deliveries from a 300,000 dwt carrier or 63 deliveries from a 200,000 dwt carrier. The limited number of deliveries from a 300,000 dwt carrier would not be feasible given geographically dispersed U.S. destinations, but the 200,000 dwt could perhaps be utilized. Assuming about 8 percent of annual consumption available for storage as indicated in the EEA report, total U.S. storage would equal 340 million gallons and delivery size for 200,000 dwt tanker would be about 68 million gallons. Average time between deliveries under this scenario would be about eight days. It should be noted, however, that consumption probably needs to equal about 4,000 million gallons per year (with 320 million gallons of available storage capacity) before the delivery system could even begin to utilize the size of vessels that yield the significant economies of scale available in crude oil shipments. Moreover, since the transport of crude oil by the 200,000 dwt plus tankers is usually from a single origin to a single destination, the costs of transporting methanol from several plants to various U.S. destinations are not likely to be as low as petroleum even in the highest demand of the national scenarios. Additionally, higher transportation costs for methanol that result from higher capital costs for stainless steel and/or specially lined tanks as well as generally higher handling costs for the product methanol when compared to crude (a raw material) will result in higher shipping costs for methanol, even in high demand scenarios.

In summary, crude is currently delivered to the U.S. from foreign destinations at a cost of 1.5 to 6 cents per gallon compared with 10 to 18 cents per gallon for methanol transport, excluding transport from Canada and Mexico. Because there are a number of additional costs in transporting methanol when compared to crude and there are economies of scale that will not be available to methanol under the highest of demand scenarios examined here, the lowest assumed transportation cost per gallon of methanol (from countries other than Mexico and Canada) is about 5-8 cents per gallon. Generally, the greater portion of this savings (perhaps two thirds) will only become possible in the national high U.S. demand scenario (above 4,000 million gallons per year). The other one-third savings (1.6-3.3 cents per gallon) may potentially be achieved at levels up to 4,000 million, though the threshold for achieving any savings (relative to the costs shown in Exhibit 5-1) is estimated to be about 250 million gallons. Exhibit 5-2 depicts the nature of the relationship between methanol transport cost and volume shipped. The location of the inflection points for this curve are highly speculative and will depend on the specific structure of the future methanol market.

EXHIBIT 5-2:
POTENTIAL ECONOMIES OF SCALE, OCEAN SHIPPING METHANOL: MIDDLE EAST TO UNITED STATES



DEMAND IN THE YEAR 2000, BY SCENARIO

A - California Low Demand	—	128	Million Gallons
B - California High Demand	—	250	Million Gallons
C - Nrtional Low Demand	—	4,252	Million Gallons
D - National High Demand	—	27,000	Million Gallons

A final note on methanol transportation costs relates to the accuracy of the estimates presented above. The estimates of the current cost of transportation as well as future potential economies of scale are rough. Generally, there is not enough methanol currently transacted in U.S. markets to make price estimates reliable. The estimates of current transportation cost per gallon of methanol between countries were developed from information contained in Competitive Methanol Production Economics, R. G. Dodge, DeWitt & Company, December 1985 and discussions with several shipping firms and freight forwarders to ensure reasonableness and estimate costs for regions not previously served. These rates are believed to be reasonable, however, particular requirements such as volume per year, loading and unloading requirements, long-term agreements, and movement of other products for the same shipper can all affect the actual contract rate. Data available on the current transportation rates for methanol are constrained to limited shipments of methanol moving in the chemical trades. Growing transportation requirements for methanol will lead to changes in the rates as larger shipments and more regular delivery patterns give methanol buyers more leverage with carriers. The rates listed in Exhibit 5-1 are representative of near-term methanol movements and are based on current chemical trade activities. These rates may vary by as much as thirty percent as a result of changing economic conditions in the tanker shipping industry. The rates shown are for a reasonably stable market. Delivering methanol to a Great Lakes destination such as Chicago will add about 2 cents per gallon over East Coast delivery rates as a result of the transloading cost from ocean to lake tankers. Delivery of methanol to many midwest locations may be less expensive if the product is shipped to New Orleans instead of Chicago and delivered by barge along the inland waterway system.[4] Differences in rates between U.S. East Coast, Gulf and California delivery points are a function of cargo origin, distance and the existence of regular chemical trades along each origin and destination. These factors will become less important as the methanol trade expands.

Generally, the widely accepted series for crude oil transport documented in Platt's Handbook and Lloyd's Shipping Economist do provide a good measure of the price of crude transport. It is certainly true that the cost of methanol transport will be higher than the price of crude transport through all scenarios, since in the highest range methanol represents less than 20 percent of the crude now transported (for all uses). Moreover, higher methanol handling costs related to tank requirements and product characteristics will also keep the price of methanol transport higher. Nonetheless, the actual delivery volumes required to improve the economies of scale for U.S. delivery of methanol are rather speculative. The demand for methanol must not only increase but remain firm, long-term agreements must be reached between producers and terminals, and U.S. terminals from different geographical locations will have to work together closely to improve the bargaining position for U.S. deliveries. The estimates are not nearly as sensitive to whether the shipments originate from Trinidad or Saudi Arabia for delivery to Chicago or Los Angeles as they are sensitive to total market demand and unified buying strategies. Moreover, the estimates given here are rough indicators of future costs and current prices of shipments. The only historical data available are for the prices charged for crude oil shipments and the actual prices charged for shipments will depend on many different factors. Extensive primary research, well beyond the limits of this study, would be required to improve the accuracy of these estimates.

Special Handling Requirements

Methanol is currently transported throughout the world as part of the chemical tanker trade. Shipment can be both liner (scheduled) and tramp (charter) and cover a broad range of volumes from 1 to 6 million gallons. In order to efficiently utilize even the smallest tanks on typical chemical tankers volumes of 3-6 million gallons per shipment are desired. As volumes increase, larger tanks can be utilized and discounts are generally provided. These vessels regularly handle cargo with corrosive, explosive and hazardous characteristics. Special international standards for tank cleaning, product handling, last load carried, and other issues are generally incorporated in contracts.

One of the two largest chemical tanker operators in the world, a Norwegian firm called Odfjell Westfol-Larsen Tankers currently transports over 300 million gallons of methanol per year. Their tankers are constructed with epoxy-lined tanks, zinc silicate-lined tanks, and stainless steel tanks. Methanol is carried in either zinc-silicate lined or stainless steel tanks. Stainless steel tankage is the most desirable for methanol, however, the smooth silicate coating associated with zinc linings offer generally acceptable tanks for methanol according to this firm. Stainless steel tanks are considerably more expensive than the coated soft steel tanks. Newly constructed chemical tankers generally have a mix of tank types. Odfjell Westfol-Larsen's tankage is 45 percent stainless, 35 percent zinc-silicate and 20 percent epoxy. The large oil tankers currently utilize soft steel tanks. According to industry specialists, a large dedicated methanol tanker would probably utilize stainless steel tanks which would increase construction cost by 10-15 percent. A major research effort is underway by the paint industry to find a methanol acceptable coating that would allow the use of lower cost soft steel tanks. The paint industry recognizes that such coatings could offer the industry a substantial market.

In addition to the reactive nature of methanol, toxicity and fire detection also require special planning and equipment. It is estimated by shippers that fire detection and suppression systems and special loading/unloading systems would add one to three percent to the cost of a production tanker.

Capacity Expansion

Methanol use in highway transportation has the potential of placing significant new requirements on the ocean transportation industry. As methanol has about half the energy value per barrel of oil, the tanker fleet may have to expand its capacity if oil imports are replaced with methanol imports. It is also possible that more methanol supply will come from foreign sources because U.S. producers may not be able to compete with low-cost producers in gas-rich countries. Currently there is an active market for used tankers of all sizes. The current fleet is well in excess of current demands with used ships currently selling for as little as $40 per dwt for VLCC/ULCC and $200 per dwt for smaller vessels. This compares to new vessel cost of $188 per dwt for VLCC/ULCC and $560 per dwt for smaller vessels. In today's spot and one year charter markets a new 250,000 dwt oil tanker costing about $50 million can generate about $18 million in revenues for the carrier per year in the spot market and $12 million per year on charters. When and if methanol shipments absorb the excess capacity currently available for tankers[5], new capital will be required.

Shipyards currently specialize in constructing one or a very few off-the-shelf vessels of standard design. Shipyard productivity, measured in man-hours per ton of erected steel, is greatly enhanced as the shipyards eliminate design problems and production bottlenecks associated with constructing the first of a series of vessels. Construction time for a large crude carrier was cut by the early 1980's from two to three years to nine months.[6] The Japanese yards' early entry into building large crude carriers, their pioneering efforts in advancing shipbuilding techniques, their access to low-cost steel produced by efficient mills and to a low-cost, highly dependable and industrious work force, their encouragement by government agencies, and the availability of government shipyard credit facilities to prospective owners has helped Japanese shipyards capture half of the world order book for new vessel construction (newbuildings).

The following sections provide a general description of the aspects and considerations involved in ocean transport. These descriptions are provided so as to give the reader a general understanding of the way shipments are negotiated.

Contract Structure

In the current methanol trade the product is carried by specialty tankers. These ships are generally much smaller (20-40,000 deadweight-tons) than crude oil tankers and usually contain 6-20 separate tanks of varying sizes. Many different products are carried on a single voyage and separate products may have unique origins and destinations. During the initial stages of a growing methanol market the product would be carried by these vessels. As of January 1, 1986 there were almost a thousand chemical tankers in the world fleet offering almost twelve million dead-weight tons of cargo space.[7] This fleet is more than adequate to service the current chemical trades and initial methanol transportation requirements. In latter stages of methanol growth, it will become economic for shippers to charter whole vessels as is now the common practice in the oil transport market.

Captive tanker fleets are currently chartered to oil companies for most or all of their useful lives on a cost-of-service basis. Under cost-of-service contracts, owners bear little or no financing or operating risks. These risks are borne by the oil companies. Owners with these contracts sell their ability to manage and operate vessels. Through these arrangements, the shipper has access to the ship management talents of competent ship operators for a relatively modest fee. The actual percentage of owned and controlled fleets to total tanker needs varies considerably among the major oil companies, depending on their experience with ownership, their relationship with independent tanker owners and shipping companies, the business philosophy of the chartering managers, their perception of future tanker needs, and the availability of corporate funds for acquiring tankers.

When there is no excess tonnage available to satisfy an incremental demand for tanker capacity, shippers must select other means to satisfy their need. They may order tankers for their own account, enter into a life-of-asset transportation agreements with a captive fleet owner, or arrange a charter (contract) with an independent tanker owner or tanker-owning shipping company on a long-, medium-, or short-term basis. Charter parties (written contracts) are concluded after considering the owner's past performance and reputation as a ship operator and his proposed rates and terms. A charter is fixed if the rates and terms are satisfactory to both the charterer and the owner; that is, when the business objectives of both parties are satisfied. They are negotiated in an extremely competitive environment with numerous owners attempting to garner contracts from a few major charterers.

Economy of Scale of Large Tankers

In the late 1940s and early 1950s, there was a plentiful supply of war-built tankers of about 16,000 dwt. These later became known as handies for their versatility in serving every oil terminal in the world. By the mid-1950s, world economic activity had absorbed all the excess war-built tonnage. In response to a growing demand for tanker capacity, certain shipyard managers, oil company chartering managers, and owners developed, ordered, and built larger-sized tankers of 20,000, 25,000, 30,000, and 35,000 dwt. In the late 1950s, the 50,000-dwt supertanker made its debut. The combination of lower operating costs and capital servicing charges to transport a ton of crude oil in these vessels provided economies of scale that led to lower shipping costs.

In 1966 and 1967, the first tankers of over 200,000 dwt, Very Large Crude Carriers (VLCCs), were delivered and within a few years there were Ultra Large Crude Carriers (ULCC) of greater than 300,000 dwt . By 1970, the world VLCC/ULCC fleet numbered 130 vessels. Exxon, Texaco, and Shell owned about a third; Greek and Hong Kong shipping firms were added to the roster of owners, who collectively owned another third of the fleet. The remaining third was owned by a Japanese Line and the British shipping company, Peninsular and Orient Steam Navigation (P & O). Even in the 1986 U.S. oil market with significantly reduced imports, about six oil tankers made U.S. deliveries per week with one being a VLCC/ULCC vessel. Thirty VLCC/ULCC's leave the Arabian Gulf each month.

If methanol demand grows to be a substantial portion of the U.S. and world transportation energy use, vessels of the VLCC/ULCC class would supply the shipping at rates similar to current crude oil rates, plus additional handling and capital costs.

Pricing

Historically, 90-95 percent of the transportation needs of the major crude shippers are filled by ownership, control of captive fleets, and an assortment of long-, medium-, and short-term chartered-in tonnage. The remainder is satisfied by open market chartering of tanker capacity on a single-voyage basis called the spot market. If the chartering manager of an oil company must transport crude oil between two ports on a specified loading date and there are no suitably sized tankers in the company's owned, controlled, or chartered-in fleet which can meet the date, the chartering manager will attempt to charter-in a vessel from the spot market. Usually he contacts brokers who, for a commission, seek out tanker owners of uncommitted, suitably sized, advantageously positioned tonnage. The search extends not just to owners but also to other oil companies. The practice of oil companies chartering out owned or chartered-in tonnage to competitors is called reletting.

A tanker on the spot market is under charter only for the duration of the loaded leg of a single voyage, which may last from a few days to a month. Once the cargo is discharged, the vessel is free to compete for another cargo wherever it happens to originate to wherever the destination, as long as the vessel is suitably sized for the intended cargo, is physically sized to come alongside the loading and discharging berths and to pass through intervening canals and restricted waterways, and can meet the desired loading date. The spot market is an extremely sensitive indicator of the marginal demand and supply of tanker capacity, a key signal to oil companies and owners on whether or not to expand the world stock of tanker capacity, and a means to allocate the worldwide fleet of tankers among the many crude oil trade routes.

Rate of freight in the spot or single-voyage market are expressed in Worldscale or Worldscale Points to facilitate the decision-making process for fixing tankers. Worldscale equates the daily revenue-earning rate of a tanker independent of any specified trade route. For example, if an owner has a tanker in the Persian Gulf and receives two offers — one to transport a cargo of crude from the Persian Gulf to Europe via the

Cape of Good Hope and the other to Japan both at Worldscale 100 (W100) — in theory, he would be indifferent because both offers would generate the same daily revenue. From a practical viewpoint, he is not indifferent. He may select the Persian Gulf to Japan (PG/Japan) to have his vessel in the Far East to take advantage of a low-cost repair yard for planned maintenance. Or he may select the longer-distance PG/Europe voyage because he feels spot market rates may be falling and wants to maintain the current daily earning rate longer. If he thinks rates are going up, he may select the PG/Japan voyage because its shorter duration would increase the vessel's earnings in a rising spot market more than selecting the longer PG/Europe voyage.

For example, assume that the Worldscale 100 rate per dwt of cargo on the PG/Europe voyage was $10 and $5.70 on the PG/Japan voyage. The round-trip time at a speed of 15 knots to complete the PG/Europe via the Cape of Good Hope voyage is about 64 days, 40 days for the PG/Japan voyage. If an owner fixes his vessel at W100 on either voyage, the gross receipts of tons of cargo carried multiplied by the W100 rates less bunker (fuel) costs, port charges, and canal tolls divided by the roundtrip voyage time would yield essentially the same daily earnings rate for both voyages. Out of the daily earnings rate, the owner must pay all operating costs (crew, maintenance, insurance, and stores) and any financing charges. The underlying basis for computing Worldscale rates by the International Tanker Nominal Freight Scale Association for over 50,000 voyages is the preservation of the earning power of a standard tanker at the base rate of W100 regardless of the voyage. Worldscale 100 rates were adjusted annually to compensate for changes in port and canal charges and bunker costs.

CHAPTER 5 FOOTNOTES

1. According to Lloyd's Shipping Economist, monthly, and Platt's Oil Price Handbook, the (comparable) cost of ocean transport of crude oil ranges from 1.5 to 6 cents per gallon in the current shipping market.

2. Based on 334.5 gallons of methanol per metric ton times 1.016 metric tons per dwt (long tons) = 339.9 gallons per dwt.

3. Energy and Environmental Analysis' report "Distribution of Methanol for Motor Vehicle Use in the California South Coast Basin, p.6-4.

4. See for example, Transportation Benefits of the Proposed Wabash Waterway, Jack Faucett Associates, December 1986.

5. According to the Lloyd's Shipping Economist, only 17 percent of tankers of 150,000 dwt plus were actively shipping in summer of 1986.

6. The world record is 2 weeks between keel laying and launching for the much smaller WWII Liberty vessels built in U.S. yards.

7. Tankers in the World Fleet, U.S. Department of Transportation, Maritime Administration, January 1, 1986.

CHAPTER 6:

PRODUCTION FROM ADDITIONAL CAPACITY

This chapter presents estimates of the cost of methanol supplied to the United States by potential new methanol plants. Significant expansion of methanol capacity will not occur until the market for methanol increases to the point that current (excess) capacity approaches full utilization. Because additional capacity will not be built unless the product can be sold at fully costed (fixed plus variable) prices, an estimate of capital costs is a key element in determining the cost of methanol from additional capacity. The location of future (hypothetical) plants was selected based on the availability of surplus natural gas (currently vented, flared or reinjected) in those countries that now produce or are preparing to produce methanol.

This chapter is divided into four sections. The first discusses the conceptual importance of total cost pricing as the current excess capacity conditions abate. As methanol fuel demand causes total methanol demand to exceed methanol supply from existing or soon to be constructed production facilities, the cost of production from new capacity will become important. Later sections present estimates of fixed and variable costs of methanol production from new plants. Finally, the last section provides a summary of fixed, variable and total costs per unit of output for additional capacity.

TOTAL COST PRICING

Chapter 4 explained the procedures used to estimate methanol prices during a period of excess supply. This chapter examines the costs that will be associated with new capital as demand grows and excess capacity diminishes. The resulting estimates are used to develop the long-run methanol supply curve.

It is a general assumption of this report that methanol is sold in a competitive market. In a competitive market it is expected that, in the long run, price will be determined by demand and the long run average total cost of producers. If price exceeds industry average total cost, economic profits are earned by existing plant owners and new firms will be attracted to the industry. The new supply will drive the price down to long run average cost. For the delivery of methanol to U.S. markets, individual producers will still have different production and delivery costs due to local prices for inputs and transportation costs.

After estimating the long-run supply curve (based on average total costs for new plants), it is also possible to calculate the "gap" in prices between the lowest cost plant on the long-run curve and the highest cost plant on the short run supply curve (based on average variable cost for existing plants). However, the potential jump in market prices may be larger or smaller than this "gap" because of the leadtime required to bring new capacity on line (larger) or the tendency of entrepreneurs to anticipate methanol demand and thereby increase capacity before demand is increased (smaller).

In general, the leadtime required to bring new methanol capacity on line has been increasing in recent years and it now takes about three years to construct new plants. However, the actual point in the transition wherein individual countries and/or entrepreneurs will make decisions to add capacity is uncertain. Because the methanol industry has, to date, anticipated market conditions, decisions to add new capacity may be made well before supply and demand come into balance. This has in the past, and may in the future, be based more on the potential for economic exploitation of otherwise underutilized gas reserves in underdeveloped countries than actual market conditions. Anticipatory decisions to build new plants will smooth the price adjustment between the short- and long-run production scenarios.

However, if the decision to build new capacity does not match the growth in demand, prices may rise above the average total cost for new plants allowing existing plants to earn excess profits (higher than the difference between the existing plants' total costs and the total cost of new plants) until new capacity comes on line. In this situation existing plants will capture a higher economic rent and the associated jump in methanol prices will be larger than the "gap" between the lowest average total cost new plant and the highest average variable cost existing plant. The economic rent earned by existing plants will then decrease to the difference between total costs of the existing plants and new plants as the new plants come into production.

POTENTIAL LOCATIONS FOR NEW PLANTS

Methanol plants could be constructed in almost any country that has associated gas, gas which is flared or reinjected, or large gas resources. Exhibit 6-1 provides estimates of natural gas reserves and production, as well as quantities of natural gas that are vented, flared or used in repressuring for selected countries. Countries that currently produce methanol are identified.

For this analysis it is assumed that only those countries that have already been identified as U.S. suppliers and have sufficient quantities of low-cost (vented, flared, reinjected) natural gas will be likely locations for new plants. This assumption is not limiting because these sources are capable of supplying more than enough methanol to meet the levels of demand specified in the scenarios of interest, as shown in Exhibit 6-2. Furthermore, it is reasonable to assume that countries which have shown a current interest in methanol production have done so because of the relative cost at which they could supply methanol. While other countries could produce methanol, their lack of interest in this market provides an indication that (1) better alternatives exist for utilization of their natural gas supply and/or (2) higher production or capital costs prevent cost-effective production. This could change as market prices for methanol increase and demand becomes more secure. Moreover, countries with high levels of low cost natural gas that do not appear on Exhibit 6-2 and do decide to produce methanol will probably do so within the range of fixed costs discussed below. The vented, flared and reinjected gas represented by countries that already supply the U.S. is enough gas to fuel the production of almost 53 billion gallons of methanol per year, or the equivalent production of 258-227.5 million gallons per year plants operating at 90 percent capacity. It should be noted that the vented and flared and reinjected natural gas shown for the U.S. is located primarily in Alaska.

FIXED COSTS

In order to estimate the fixed cost of methanol production from potential new plants a number of assumptions are required. These include: 1) the size of new methanol plants, 2) the capital cost for new plants, 3) the appropriate rate of return on investment, 4) the assumed number of years over which plants should be depreciated, and 5) the countries that will potentially build new plants. Each of these assumptions is discussed below. The sum of all fixed costs divided by output over the life of the plant generates the estimate of average fixed cost (stated as cents per gallon of output).

EXHIBIT 6-1:

WORLD NATURAL GAS PRODUCTION, 1983 AND RESERVES AS OF JANUARY 1985

Region / Country	Methanol Capability In Place	Gross Production (Bcf)[3]	Vented Flared (Bcf)[3]	Reinjected (Bcf)[3]	Reserves (Tcf)[3]
NORTH AMERICA					
Canada	X	3,441	60	431	92.3
Mexico	X	1,480	166	NA	77.0
United States	X	18,597	95	1,458	197.5
TOTAL		23,518	321	1,889	366.8
CENTRAL AND SOUTH AMERICA					
Argentina	X	570	95	32	24.6
Bolivia		178	7	79	b
Chile	X	170	0	117	b
Colombia		183	26	55	b
Trinidad and Tobago	X	212	86	0	10.6
Venezuela		1,122	61	454	55.4
Other	X	237	75	31	17.4
TOTAL		2,672	350	768	108.0
WESTERN EUROPE					
France	X	337	0	0	b
Germany, West	X	629	0	0	b
Italy	X	462	0	0	b
Netherlands	X	2,638	1	0	68.5
Norway	X	1,079	10	165	89.0
United Kingdom	X	1,774	134	166	27.8
Other	X	244	4	15	21.4
TOTAL		7,162	149	346	206.7
EASTERN EUROPE AND U.S.S.R					
Germany, East	X	268	0	0	b
Hungary		238	0	0	b
Poland		193	0	0	b
Romania		1,409	5	0	b
U.S.S.R	X	19,490	380	NA	1450.0
Other	X	47	0	0	16.5
TOTAL		21,646	385	0	1466.5

WORLD NATURAL GAS PRODUCTION, 1983 AND RESERVES AS OF JANUARY 1985

Region Country	Methanol Capability In Place	Gross Production (Bcf)[3]	Vented Flared (Bcf)[3]	Reinjected (Bcf)[3]	Reserves (Tcf)[3]
MIDDLE EAST					
Bahrain	X	186	16	28	7.3
Iran		908	454	127	478.6
Iraq		142	119	0	28.8
Kuwait		192	21	20	36.6
Qatar		194	3	0	150.0
Saudi Arabia	X	950	576	46	127.4
United Arab Emirates	X	548	216	0	32.0
Other		242	56	57	8.7
TOTAL		3,360	1,460	278	869.4
AFRICA					
Algeria	X	3,173	154	1,592	109.0
Egypt		143	26	0	7.0
Libya	X	441	68	226	21.2
Nigeria		536	442	13	35.6
Other		205	136	29	14.4
TOTAL		4,499	826	1,860	187.3
FAR EAST AND OCEANIA					
Australia	X	462	39	0	17.9
Brunei		345	14	0	7.3
China	X	480	49	0	30.9
Indonesia	X	1,186	151	256	40.0
Malaysia	X	196	65	0	50.0
Pakistan		347	0	0	15.8
Other	X	633	35	11	35.2
TOTAL		3,649	353	267	197.1
WORLD TOTAL		66,506	3,845	5,407[a]	3401.8

[a]Sum of reported totals only.

[b]Included in regional other reserves.

NA = Not available.

Note: Sum of components may not equal total due to independent rounding.

Source: Energy Information Administration, International Energy Annual, 1984, DOE/EIA-0219(84).

EXHIBIT 6-2: POTENTIAL ANNUAL METHANOL SUPPLY, SELECTED COUNTRIES[1]

Country	Vented and Flared (Bcf)	Reinjected (Bcf)	Total (Bcf)	Total (Billion Btu)	Potential Methanol Supply[2] (Million Gallons)
U.S.	95	1,458	1,553	1,601,143[3]	15,206
Canada	60	431	491	490,509	4,658
Mexico	166	NA	166	159,858	1,518
Argentina	95	32	127	118,364	1,124
Brazil	35	25	60	61,980	589
Chile	0	117	117	116,883	1,110
Trinidad	86	0	86	90,042	855
Algeria	154	1,592	1,746	1,852,506	17,593
Bahrain	16	28	44	46,068	437
Saudi Arabia	576	46	622	651,234	6,185
U.A. Emirates	216	0	216	226,152	2,148
Burma	5	5	10	10,470	99
China	49	0	49	51,303	487
India	21	5	26	26,884	255
Malaysia	65	0	65	67,210	638
TOTAL	1,639	3,739	5,378	5,570,606	52,902

SOURCE: Energy Information Administration

NA = Not Available

[1] This exhibit is limited to countries which have indicated current interest in producing methanol for U.S. supply. Other countries with natural gas may also provide additional sources in the future. (See Exhibit 6-1)

[2] Based on a 1990 forecast of 0.1053 million Btu per gallon methanol average natural gas consumption. This factor was taken from the Chem Systems report entitled The Outlook for Natural Gas Use in Methanol and Ammonia Production in the U.S., prepared for the American Gas Association, March 1983, p.28, table III-F-1.

[3] Located primarily in Alaska.

New Plant Size

A basic assumption required to calculate the fixed cost of methanol production from new plants is the size of the new plants. For this analysis it is assumed that the size of new plants will be 2000 tons per day or 227.5 million gallons per year. Plants with capacities of 500 tons per day (tpd) for a single train were considered large in the early 1970's. Much larger single-train plants of 2,000-2,500 tpd are the current standard, resulting in reduced costs through economies of scale in production. Although 5,000 tpd single-train unit designs are reportedly available, no significant economy of scale advantage is predicted beyond the 1,500-2,000 tpd range.

Capital Costs for New Plants

A second assumption that must be made in order to estimate the fixed costs of new capacity is the capital cost of new plants. Capital costs, when coupled with assumptions on depreciation schedules and rates of return, represent a large share of fixed costs.

Numerous sources provide estimates of the capital cost of new methanol plants. Tenneco estimates costs to be $200 million for a 600,000 metric ton per year plant (200.7 million gallons per year) in the U.S. Gulf or Western Europe. Similar size plants in remote locations could cost $300 million.[1] The World Bank estimates new methanol plants to cost between $175 and $335 million for a 2,000 tons-per-day plant (227.5 million gallons per year) depending on the level of development of both the site and country in which the plant is located. Costs of $106.5 to $205 million are estimated for a plant one-half of this size.[2] Chem Systems estimates a plant with a 113.5 million gallon plant built in the U.S. Gulf in 1980 would have cost $101.7 million.[3] Jean M. Tixhon of the International Finance Corporation, estimated a cost of $300 million for a 2,000 ton-per-day (227.5 million gallons per year) theoretical project. It was noted that the rather high total cost was related to a remote location that required a power plant, harbor and housing compound.[4] Dewitt and Company has estimated the base cost of a world class facility to be $215 million.[5]

While there is a great deal of variance in these estimates, there is general agreement that a plant of 227.5 million gallons per year would cost from $200 to $300 million per year depending upon location and available infrastructure. To adjust for differences in location and infrastructure, representative capital costs were chosen for categories of countries. The developed countries (U.S. and Canada) have been assigned capital costs of $200 million. However, it should be noted that much of the available surplus gas in the U.S. is located in Alaska which would most likely require much higher capital cost. Countries that are either fairly developed or have a substantial petroleum industry, and thus have reasonably developed international transportation facilities, have been assigned capital cost of $250 million. These countries include Mexico, Algeria, Saudi Arabia, Bahrain, and the United Arab Emirates. The less developed countries (Argentina, Brazil, Chile, Trinidad, Burma, China, India, and Malaysia) have been assigned capital cost of $300 million to account for higher infrastructure and general development costs.

Exhibit 6-3 presents per plant capital costs by country and the resulting costs per gallon required for the rate of return and payback of the cost of capital discussed below.

Rate of Return on Investment

The rate of return on investment for new methanol plants is assumed to be 20 percent before taxes. Most of the sources reviewed for this study estimated a rate of return of 15 percent or higher. The World Bank, for example used a required rate of return on investment (ROI) of 20 percent before taxes in estimating the range of production costs for new gas-based methanol plants. Sources also noted that the return could be higher with higher than usual debt financing as well as risk levels that can be associated with location in some countries. The ROI is a function of a number of factors that together reflect the cost of capital and associated risk based on market conditions and location factors. Income tax laws, subsidies, and overall stability of government (including protection of private ownership rights) are relevant. The 20 percent rate used here could be low (in high risk locations) or high (if governments subsidize plants) but probably represents a reasonable average of ROIs that will be required for future plants.

The per-unit cost associated with the required rate of return is calculated by multiplying the capital cost by the required rate of return (0.20) and dividing by total annual production of the plant (227.5 million gallons).

EXHIBIT 6-3:
CAPITAL COSTS AND OTHER COMPONENTS OF FIXED COSTS FOR NEW (227.5 MILLION GALLON) METHANOL PLANTS BY COUNTRY
($ 1986)

Country	Capital Cost ($, Million)	Return on Investment[1] (¢/gallon)	Capital Charge: Depreciation[2] (¢/gallon)	Total Fixed Costs Related to Capital[3]
U.S.[4]	200	17.58	5.86	23.44
Canada	200	17.58	5.86	23.44
Mexico	250	21.98	7.33	29.31
Argentina	300	26.37	8.79	35.16
Brazil	300	26.37	8.79	35.16
Chile	300	26.37	8.79	35.16
Trinidad	300	26.37	8.79	35.16
Algeria	250	21.98	7.33	29.31
Bahrain	250	21.98	7.33	29.31
Saudi Arabia	250	21.98	7.33	29.31
U.A. Emirates	250	21.98	7.33	29.31
Burma	300	26.37	8.79	35.16
China	300	26.37	8.79	35.16
India	300	26.37	8.79	35.16
Malaysia	300	26.37	8.79	35.16

[1]Based on a 20 percent ROI, before taxes.

[2]Based on a 15 year life.

[3]Fixed costs related to maintenance and overhead including taxes, insurance, etc., are included in estimates of variable costs in Exhibit 6-4.

[4]Reflects location of plants in the mainland U.S., excluding Alaska. While most of the vented-flared-reinjected gas is in Alaska, adverse conditions including lack of infrastructure, weather, and government restrictions on development of many regions will most likely limit production in Alaska, except for local use. Capital costs for Alaska would be significantly higher should plants be constructed in locations where gas is currently vented and flared or reinjected. Capital costs for Alaska were not estimated in this study.

Depreciation

The annual capital charge on a per gallon basis is calculated by dividing the total capital cost by the assumed number of operating years and the yearly production of the plant. For this analysis it is assumed that the life of a methanol plant will be fifteen years. This estimate combines actual estimated operating life of the plant (20+ years) with realistic assumptions about the payback that investors will desire in projects of this type, perhaps as short as 2 years.

VARIABLE COSTS

The variable costs in new methanol plants are calculated using the same procedures explained in Chapter 4 for existing plants except that feedstock costs are assumed to be 5 percent lower for new plants due to energy reduction measures that will be incorporated in plant design. This efficiency change is based on information presented in the Chem Systems report and by others noting that increases in energy costs in the last decade are providing economic incentive for energy reduction measures in plant design. Variable costs by category and country for new methanol plants (227.5 million gallon per year) are provided in Exhibit 6-4. As discussed in Chapter 4, each category of costs presented includes fixed and variable cost of the type specified. The total amount of fixed costs included are small as most of the fixed costs for methanol are related to capital (see Exhibit 6-3).

TOTAL COSTS

The total costs associated with methanol from additional capacity are shown in Exhibit 6-5. These costs range from 43.5 to 54.5 cents per gallon in 1986 dollars. The fixed costs, ranging from 23 to 39 cents per gallon, represent in all cases except the U.S. more of the total cost than do variable costs (14 to 20 cents), in some cases up the three times the variable costs. The relative size of fixed costs are important because these amounts represent the approximate size of the market (plant gate) price increases that will occur as the market shifts from variable to total cost pricing. These costs are also very high relative to transportation costs and will clearly affect the delivered market price of fully costed product more than variable or transportation costs (less than 18 cents per gallon). The assumptions in these fixed costs are straightforward: a

EXHIBIT 6-4:

SUMMARY OF AVERAGE VARIABLE COSTS OF METHANOL PRODUCTION FROM NEW PLANTS, BY COUNTRY

(Cents Per Gallon, 1986 $)

Country	Feedstock	Maintenance	Catalyst	Utility[1]	Labor	Other[2]	Total
U.S.[3]	21.12	2.59	1.00	1.46	0.97	3.37	30.52
Canada	12.67	2.59	1.00	0.93	0.84	3.37	21.40
Mexico	4.23	3.36	1.00	1.46	0.35	3.37	13.77
Argentina	2.11	4.14	1.00	0.48	0.32	4.20	12.25
Brazil	4.23	4.14	1.00	0.48	0.32	4.20	14.37
Chile	4.23	4.14	1.00	0.48	0.32	4.20	14.37
Trinidad	4.23	4.14	1.00	0.54	0.38	4.20	14.49
Algeria	4.23	3.36	1.00	0.87	0.33	4.20	13.99
Bahrain	4.23	3.36	1.00	0.87	0.51	4.20	14.17
Saudi Arabia	4.23	3.36	1.00	0.87	0.51	4.20	14.17
U.A. Emirates	4.23	3.36	1.00	0.87	0.51	4.20	14.17
Burma	8.46	4.14	1.00	1.17	0.27	4.20	19.24
China	8.46	4.14	1.00	1.17	0.27	4.20	19.24
India	8.46	4.14	1.00	1.17	0.27	4.20	19.24
Malaysia	8.46	4.14	1.00	1.17	0.27	4.20	19.24

Note: Each category shown includes all costs, fixed and variable, of the type specified. The total fixed costs included are small as most of the fixed costs for methanol are related to capital and shown separately in Exhibit 6-3. To the extent that the costs above differ from those shown in Chapter 4, it is because of the plant size and/or the increased efficiency estimated for future plants affects the variable indicated.

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[1] Includes charges for power, cooling water, and makeup water.

[2] Includes charges for insurance, general and administrative, selling, and overhead costs.

[3] Reflects location of plants in the mainland U.S., excluding Alaska. While most of the vented, flared, reinjected gas is in Alaska, adverse conditions including lack of infrastructure, weather, and government restrictions on development of many regions will most likely limit production of methanol in Alaska, except for local use. In Alaska, feedstock costs would be lower but all other costs would be higher than indicated. Production costs for Alaska were not estimated in this study.

EXHIBIT 6-5:
TOTAL PRODUCTION (PLANT-GATE) COSTS FOR NEW CAPACITY, BY COUNTRY
(Cents per gallon, 1986 $)

Country	Fixed Costs (Capital)	Variable Costs[1]	Total Production Costs
U.S.	23.44	30.52	53.96
Canada	23.44	19.95	43.39
Mexico	29.31	13.67	42.98
Argentina	35.16	12.25	47.41
Brazil	35.16	14.37	49.53
Chile	35.16	14.37	49.53
Trinidad	35.16	14.49	49.65
Algeria	29.31	13.99	43.30
Bahrain	29.31	14.17	43.48
Saudi Arabia	29.31	14.17	43.48
U.A. Emirates	29.31	14.17	43.48
Burma	35.16	19.24	54.40
China	35.16	19.24	54.40
India	35.16	19.24	54.40
Malaysia	35.16	18.53	53.69

[1]Include some fixed costs that could not be separately estimated including labor, maintenance and other costs.

20 percent before tax rate of return and a 15-year depreciation schedule with capital costs ranging from $200-$300 million, depending on location. While it is clear that the analysis undertaken herein is influenced tremendously by the capital cost assumptions, it is equally clear that any reasonable range of these costs will not significantly alter their overall influence on the total cost of methanol, including transportation, delivered to U.S. destinations.

CHAPTER 6 FOOTNOTES

1. Tenneco, "Methanol, World Supply/Demand Outlook," a paper presented by R. E. Simmons at the 1985 National Conference on Alcohol Fuels, p.18.

2. World Bank, Emerging Energy and Chemical Applications of Methanol: Opportunities for Developing Countries, April 1982, p.42.

3. Chem Systems, Inc., The Outlook for Natural Gas Use in Methanol and Ammonia Production in the U.S., Prepared for the American Gas Association, Mary 1983, p.26.

4. Jean M. Tixhon, "Financing Methanol Plants from an Investor's Perspective," Presented to the 1985 World Methanol Conference, Amsterdam, The Netherlands, December 9-11, 1985, p. IX-5.

5. R.G. Dodge, "Competitive Methanol Production Economics," presented to the 1985 World Methanol Conference, Amsterdam, The Netherlands, December 9-11, 1985, Appendix.

CHAPTER 7:

THE DELIVERED PRICE OF METHANOL

The preceding chapters have presented the potential world supply of methanol from the existing capital stock and from future capital stock. For each country with methanol capacity, estimates of the production cost per unit of output and current transportation cost to U.S. markets were developed. This chapter combines the estimates of production costs from current capacity with current transportation costs and also presents estimates of production plus transportation costs of future capacity that will be required to supply the demand levels set forth in the scenarios examined.

The price a product sells for in the marketplace is determined by many factors. These include the cost of producing, delivering and selling the product from various sources and the willingness of consumers to pay for the product. Some consumers may have a higher value-in-use for the product than other consumers and are thus willing to purchase the product at higher prices. When the market price is lower than some consumer's willingness-to-pay, these consumers receive benefits in the form of lower product expenditures or what economists refer to as consumer surplus. Likewise, those producers with low costs relative to the market price will earn profits in addition to what is required to attract their capital to the market and these producers enjoy a producer surplus.

Commodity markets, like that for methanol, are characterized by their highly competitive nature, generally uniform average costs across producers and the overall mobility of capital. Generally, it can be said that potential producers of methanol fall into two categories, those who have capital in place to produce methanol and those who have no capital in place but have access to both the funds and the technology needed to produce methanol. The decisions of these two groups to produce methanol are based on a different set of requirements. Since the producer with capital in place must view his capital cost as sunk, he is willing to produce when the price he receives for his product exceeds his average variable cost. That is, he will produce when he can receive more in return for his product than the direct costs he must incur to produce. This production will occur even though he may be unable to cover the fixed costs associated with the previously built capital. Alternatively, new producers will not invest unless they have reasonable expectations of selling their output at a price that provides full cost coverage including an expected return on the investment at least equal to their next best opportunity for investment.

The availability of low cost natural gas and the prospect for large-scale methanol use as a transportation fuel or as an additive (e.g. MTBE) has led to large-scale capacity additions to the methanol production industry. Capacity has been added even though growth in traditional methanol markets is only expected to slightly exceed economic growth. Large increases in production capacity have been recently completed and several other projects are under consideration. This extensive production capacity substantially exceeds the current or forecasted demand for methanol in traditional uses. Thus this new investment has been drawn by speculative increases in methanol demand e.g., transportation use, or the belief by new producers that they can undercut the delivered cost of methanol from existing facilities. Some also suggest that third-world countries could be providing large subsidies to new methanol plants to extend local economic development through the use of underutilized natural gas reserves. These government subsidies could be based on the hope that the market will increase (and subsidies will be recouped) or simply represent a form of domestic welfare that has the net effect of lowering the delivered price of methanol to the United States.

These issues need not be resolved for the purpose of this study. Here the interest is in determining what the market price of methanol will be under a set of alternative use scenarios for methanol in transportation. These scenarios were predetermined by a set of assumptions about the use of methanol as an ozone attainment strategy. Two scenarios concentrate on the South Coast Air Basin in California and another two assume a much larger market for methanol concentrated in regional markets across the country. The scenarios are presented in Exhibit 7-1. Of particular interest in the national scenario is the point that new capacity will be required to meet methanol demand.

Ultimately the market price for methanol will be determined by the options available to consumers and the cost of products and delivery. In this study, the intent is to understand the minimum compensation producers will require to deliver fuel methanol to various U.S. markets under defined scenarios. Demand is given, and can be assumed to originate from market forces or government fiat. While the forecasts cannot be expected to yield precise estimates of market clearing prices, they can help public

EXHIBIT 7-1:
U.S. METHANOL DEMAND SCENARIOS:
TRANSPORTATION USE ONLY
(Millions of Gallons)

Year	California Low Demand Case	California High Demand Case	National Low Demand Case	National High Demand Case
1988	—	7	—	—
1990	—	21	—	150
1991	11	47	138	150
1992	11	59	282	3,300
1993	22	82	421	6,500
1994	25	95	646	9,800
1995	28	108	890	13,000
1996	46	136	1,255	15,800
1997	55	154	1,670	18,600
1998	71	180	2,375	21,400
1999	103	219	3,216	24,200
2000	128	252	4,252	27,000

policy analysts to understand how the market operates and to estimate the effect of selected public policies.

Nontransportation demand for methanol is expected to grow at a rate slightly greater than the growth in Gross Domestic Product (GDP) for developed nations. For the purpose of this study methanol demand growth in traditional uses is assumed to be 4 percent per year or about one percent higher than historic GDP growth. Since some demand will be satisfied by producers that will not supply the U.S., total demand was adjusted downward so that the demand that will compete with the U.S. market could be identified as shown in Exhibit 7-2.

THE PRICE IN THE CURRENT (SHORT RUN) MARKET

In order to estimate at what price the market will be willing to deliver a specified level of product, it is necessary to estimate the industry supply curve. The current structure of the methanol industry is competitive, with some producers enjoying lower cost than others due to more efficient capital, lower feedstock cost, and government subsidies. The average cost of production for plants located in countries that have capacity available for the world as well as the U.S. market is presented in Chapter 4. Based only on capacity availability, the U.S. plants could supply more of U.S. demand but the cost data indicate that plants in Central and South America can deliver products to California for under $.30 per gallon, even with capital recovery and profit included for these low-cost facilities. Most U.S.-based plants cannot compete with the price offered by these low cost facilities, because though capital and transportation costs may be lower, high natural gas prices in the U.S. keep the U.S. producers' costs high.

Exhibit 7-3 presents the short-run supply curve for the current methanol suppliers that may be expected to provide methanol to the U.S. market. The upper curve represents the average delivered price, including transportation costs, for each country. The lower curve presents the associated average variable production costs. It should be noted that the top curve (delivered prices) establishes the shape of the U.S. supply curve. The lowest average cost (including transportation) producer is shown on the left with each step in the function representing the next highest average cost producer, by country. The length of each step approximates 90 percent of the annual methanol capacity in that country. In order to determine the minimum acceptable delivered price for methanol under each scenario, add the scenario demand from Exhibits 7-1 and the

EXHIBIT 7-2:

WORLDWIDE METHANOL DEMAND SCENARIOS: ALL USES

(Millions of Gallons)

	Projected Worldwide Demand, Excluding U.S. Transportation Use			Worldwide Noncaptive Demand, Including U.S. Transportation Use			
Year	Total[1]	Demand Not Competing with U.S.[2]	Demand Competing with U.S. Demand	California Low Demand Case	California High Demand Case	National Low Demand Case	National High Demand Case
1990	5,700	2,500	3,200	3,200	3,220	3,200	3,350
1995	6,900	3,000	3,900	3,930	4,010	4,890	16,900
2000	8,400	3,200	4,700	4,830	4,950	8,950	31,700

[1] A four percent growth rate for chemical methanol demand is assumed. This is because the demand for chemical methanol has been observed to increase with GNP in developed countries.

[2] It is assumed that this quantity of demand will be satisfied by countries that do not supply the U.S. As shown in Exhibit 3-3, there is 3.751 billion gallons of nameplate capacity for non-U.S. suppliers of which 625 million gallons is dedicated for conversion to gasoline (New Zealand). The remaining 3.1 billion in capacity (and future additions to that capacity) is assumed to operate at about 80 percent utilization in supplying noncompeting methanol users. Thus, the number in the table is estimated based on an assessment of available capacity, not actual market demand.

Source: EEA and JFA estimates.

competing demand from Exhibit 7-2, and read the minimum delivered price from the top supply curve from Exhibit 7-3. The estimates used to develop these curves are presented in Exhibit 7-3.

PRICE IN AN EXPANDING MARKET

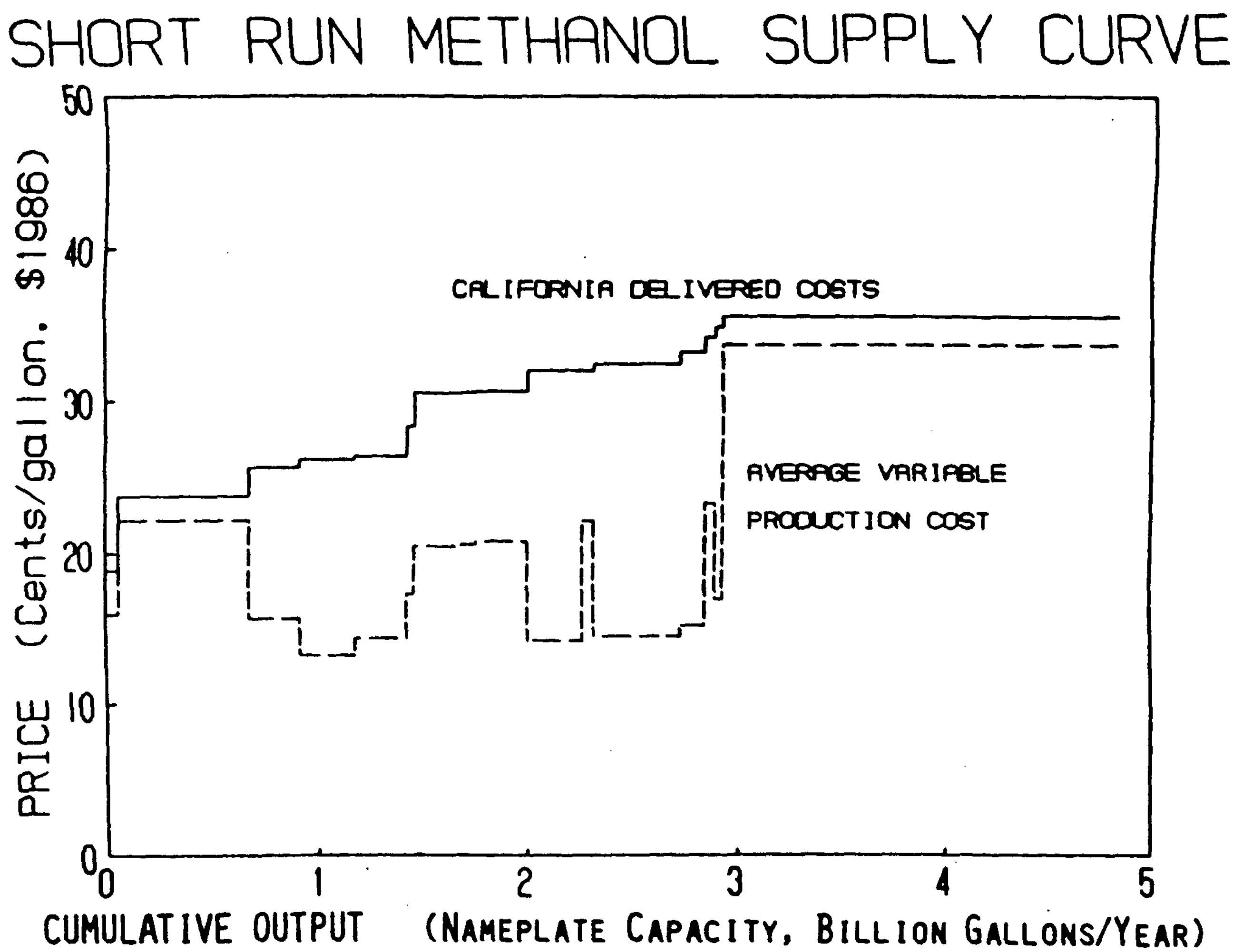
Exhibit 7-4 presents the long run supply curves for methanol based on long run average variable cost in each location, with and without transportation costs. For comparison, the short run supply curves are superimposed on the left side of the graph. Again, the lower curve shows production costs only, and the higher curve indicates the average delivered U.S. prices. The long-run transportation costs are estimated at about one-half of the transportation costs shown for the short run. This estimate captures most of the savings that are available for large-scale methanol shipments (see Exhibit 5-2). The gap between the two curves identifies the price transition between the short and long run: the actual curve may smooth between these two points if the market responds to increased demand in an orderly and organized manner. It is incumbent on policy makers, interested in promoting and planning for methanol as a transportation fuel, to anticipate the market adjustments that will be required between the short and long run supply conditions and ease the transition period.

The long run curve is much flater than the short run, reflecting the use of common technology in plants of equally efficient sizes in all countries. Assumed feedstock cost and capital requirements account for most of the production cost difference across countries. In the long run, all producers' costs will converge such that the supply curve will approximate the industry average cost curve. To the extent that some producers can maintain certain cost advantages, they will earn economic rents for the remaining useful life of their resources. In the short run, new capital may find it difficult to compete with some of the capital in place and already partially depreciated. However, within approximately the expected useful life of recently built capital most capacity should approach the same production cost per gallon. It should be noted that delivered U.S. cost may differ even in the long-run due to country-specific natural gas costs and transportation costs for delivery to U.S. markets.

SENSITIVITY OF THE ESTIMATES

In order to develop the supply curves presented in Exhibits 7-3 and 7-4, a number of limiting assumptions were required. If these assumptions are changed, the delivered

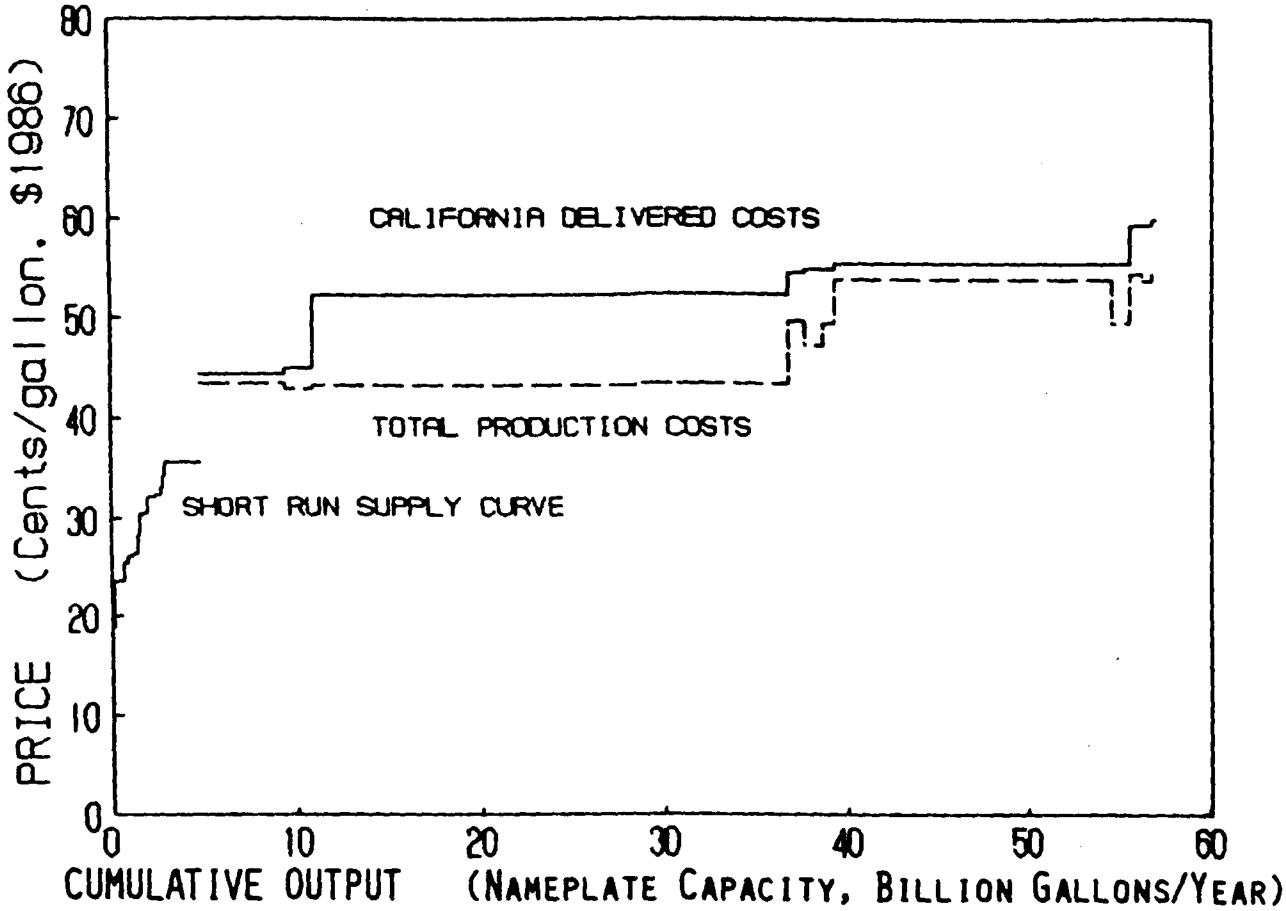
EXHIBIT 7-3:



COUNTRY	CAPACITY	CUMULATIVE CAPACITY (MIL.GAL./YR)	PRODUCTION COST	DELIVERED PRICE (CENTS/GAL.)
1 MEXICO	60	60	15.9	18.9
2 CANADA	625	685	22.1	23.7
3 TRINIDAD	230	915	15.6	25.6
4 ARGENTINA	261	1,176	13.2	26.2
5 CHILE	250	1,426	14.4	26.4
6 BRAZIL	45	1,471	17.3	28.3
7 MALAYSIA	220	1,691	20.5	30.5
8 TAIWAN	64	1,755	20.6	30.6
9 CHINA	256	2,011	20.8	30.7
10 ARAB EMIRATES	267	2,278	14.1	32.1
11 BURMA	50	2,328	22.1	32.1
12 SAUDI ARABIA	416	2,744	14.5	32.5
13 BAHRAIN	110	2,854	15.2	33.2
14 INDIA	50	2,904	23.3	34.3
15 ALGERIA	36	2,940	16.9	34.9
16 U.S.	1,900	4,840	33.7	35.7

EXHIBIT 7-4:

LONG RUN METHANOL SUPPLY CURVE



COUNTRY	CAPACITY (MIL. GAL./YR)	CUMULATIVE CAPACITY (MIL. GAL./YR)	PRODUCTION COST (CENTS/GAL.)	DELIVERED PRICE (CENTS/GAL.)
* CURRENT CAPACITY	- -	4,840	- -	- -
1 CANADA	4,600	9,440	43.4	44.4
2 MEXICO	1,500	10,940	43.0	45.0
3 ALGERIA	17,600	28,540	43.3	52.3
5 ARAB EMIRATES	2,000	30,540	43.5	52.5
4 BAHRAIN	400	30,940	43.5	52.5
6 SAUDI ARABIA	6,000	36,940	43.5	52.5
7 TRINIDAD	800	37,740	49.7	54.7
8 ARGENTINA	1,000	38,740	47.4	55.0
9 BRAZIL	600	39,340	49.5	55.0
10 U.S.	15,200	54,540	54.0	55.5
11 CHILE	1,000	55,540	49.5	55.5
12 CHINA	500	56,040	54.4	59.4
13 BURMA	100	56,140	54.4	59.4
14 MALAYSIA	600	56,740	53.7	59.4
15 INDIA	200	56,940	54.4	59.9

methanol prices suggested by these supply curves would also change. The key data development tasks that underlie these prices were the development of variable and fixed costs of methanol production and the transportation costs incurred by various producers to deliver methanol to U.S. ports. Other studies have suggested higher U.S. delivered prices for methanol than the estimates here, in some cases without the detailed breakdown of the components of the supply curves presented in this study. The following paragraphs discuss the sensitivity of the methanol prices presented in this report with respect to each of the major cost components.

The estimates of variable production costs were developed from a series of engineering estimates of methanol production cost. The components of variable cost, in order of importance, were feedstock, maintenance, catalyst, utility, labor and a catchall category of remaining costs labeled as other costs. An increase in the level of any of these categories would result in an upward shift in the supply curve, requiring higher market prices to meet specified levels of demand. Manufacturers should continue to produce only if all variable costs are recovered at market prices.

The most important component of variable cost is the feedstock expense. For the purpose of this study it was assumed that, except for plants located in the U.S. or Canada, natural gas used for methanol production had little or no opportunity cost. That is, if it were not used for methanol production, it probably would not be utilized at all. The cost for a feedstock with little or no opportunity cost is only the cost of collecting the gas and delivering it to the plant. These costs ranged from $.25 to $1.00 per million Btu. For methanol production outside the U.S. and Canada, feedstock costs represent only 30%-40% of total variable costs. For U.S. plants, a market price for feedstock of $2.50 per million Btu's was assumed. These costs represent 70% of U.S. plant total variable costs. The estimates presented in this report would change significantly if the assumption of little or no opportunity cost for feedstock is modified. If feedstock costs for all non-U.S./Canada plants were increased by $1.00 per million Btu's, the delivered price of methanol for both long- and short-term supply curves would increase by approximately $.09 per gallon. If the U.S. feedstock price was assumed for all plants, the required methanol price would increase approximabely $0.13-$0.17 per gallon. As the demand for natural gas as a feedstock for methanol plants increases, a myriad of market forces will affect market prices. Competing demands for natural gas and feedstock substitutes for natural gas will be important. More research is required to better understand how natural gas prices and/or collection costs might change as methanol demand grows.

The smaller categories of catalyst, utility, and labor cost, collectively account for only 15%-20% of the variable costs. Most documents reviewed showed little variance in these categories. "Other" costs account for as much as 25% of total cost, but include several small categories. Again, most sources agree as to the importance of each of the subcategories. Maintenance costs also account for about 25% of the estimated cost. Data on these cost are well known from existing facilities, although some remote sites could require maintenance cost levels higher than estimated here. For example, if methanol was produced by plants located on the North Slope of Alaska, higher maintenance costs could result that would increase the level of maintenance assumed in this study for remote production sites.

Short-run supply is not sensitive to fixed costs, however, some small fixed cost items are included in some of the variable cost categories. In the analysis it is assumed that these fixed costs are small and thus do not have a major impact on the short run methanol prices.

Long-run prices, expected to provide full recovery of capital and a return that reflects project risk and market opportunities are sensitive to assumptions on the cost of the plant, the productive life of the plant, and the rate of return. For all plants except those located in the U.S. and Canada, the assumed return on investment per gallon of methanol produced is greater than the long-run scenarios' variable costs of production. Return on investment and depreciation account for 65%-75% of the total methanol production costs. If the required rate of return is changed by 5 percentage points (up or down), the change in the per gallon total cost is approximately 7 cents. If the assumed depreciable life of the plant is increased from 15 to 30 years, the depreciation per gallon would be reduced by approximately 4 cents. More research is required to further refine the assumptions related to capital costs, capital recovery and return on investment. Moreover, technology may be expected to offer cost reductions, especially in remote locations.

A review of Exhibits 7-3 and 7-4 will highlight the importance of transportation cost in the delivered price of methanol to the United States. After adjusting for higher capital and handling costs, the observed transportation cost for crude oil provides a very good model for the scale economics that may be realized in ocean methanol transportation as volume grows and the product is moved more efficiently. Technological innovations related to the safe handling of methanol may allow methanol transportation costs to more closely approach crude oil transportation costs. In this study it is assumed that a small premium over crude oil transport cost will always be required for methanol transport. If scale economies could be realized at lower volume than has been assumed, transportation costs could be cut for the evaluated scenarios by a few cents per gallon. However, multiple locations for production facilities and the need to deliver the product directly to end use markets (no refinery link as with crude oil) may offset savings gained from increased volume by limiting the size of the vessels employed. Much additional research is required before more precise estimates of future methanol transportation costs can be developed.

In summary, the delivered price of methanol will be determined by a wide range of market forces that are difficult to predict. Future petroleum and natural gas availability and prices, and the acceptance by consumers of the technology and the fuel will have significant influences. The analysis throughout this report was based on an assumed level of demand, by specified scenarios, and thus does not reflect any price effects of competing transportation fuels or market barriers that might arise from consumer preferences. As developed, the prices in this study are subject to change as a result of new assumptions or better information.

USE OF THE ESTIMATES

The estimates presented in this report are designed to provide a preliminary tool to policy makers involved in the consideration of methanol as a U.S. transportation fuel. Though developed with sparse data and limiting assumptions, these estimates offer a crude approximation of the short and long run methanol supply horizon. They are not intended to predict, for a given point in time, the market clearing price of methanol product. To limit this type of application, the estimates were intentionally stated in 1986 dollars. The value of these estimates are to policy makers who must plan now for the "what if" scenarios that must accompany stable growth and smooth transition to the use of fuel methanol. With additional research and time, these estimates will be debated, criticized, and ultimately modified using more accurate production costs and supply constraints. Suppliers, by adding new capacity and maintaining idle capacity in the face of a market that does not come close to demanding the potential available supply, are already positioning themselves for an expanding methanol market.

It is now time for the demand side to catch up. Planners need to move quickly to formulate strategies that will begin to capture the short-term benefits offered by suppliers that are willing to sell at less than fully-costed prices. The methanol marketplace now offers an advantage to planners: a cushion of supply that will ease the potentially burdensome and costly pressures of a marketplace wherein demand growth exceeds supply. Moreover, if the demand component can organize and plan an orderly transition to fuel methanol, the supply side has already demonstrated an eagerness to keep one step ahead and anticipate future supply requirements. However, if the demand for methanol fuel fails to move forward in the short run, suppliers will react by closing the idle plants, withholding funds for additional capital expenditures and generally will move into other investment areas that offer a more reasonable return and a more stable environment. Though enterpreneurs will move quickly into a market where they perceive reasonable demand promise, they will move with equal haste out of a market wherein the demand promise fails to materialize in the marketplace.

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APPENDIX A:

THE INTERRELATIONSHIPS OF CRUDE OIL, PETROLEUM, NATURAL GAS AND METHANOL

RELATIONSHIP BETWEEN CRUDE OIL AND NATURAL GAS PRICES

Recent studies of the decline of crude oil prices and the effect on natural gas prices indicate that for each 1 percent decrease in crude oil prices, there may be as much as a 0.7 percent decrease in natural gas prices on average through 1990. After 1990, if crude oil prices remain low, there may be upward pressure on natural gas prices due to the decreased exploratory drilling associated with low prices and decreased additions to reserves, but they will likely remain lower than they would have been in the absence of the reduced oil prices.

American Gas Association Forecasts

The most detailed analysis of oil and natural gas prices is that produced by the American Gas Association using its Total Energy Resource Analysis (TERA) model. TERA is a system of supply, price, and demand models for gas, coal, oil, and other energy sources, that produces annual energy forecasts by region, through the year 2000. In a recent TERA-based study (April 19, 1986), AGA analyzed the effects of sustained lower oil prices on U.S. natural gas prices. Two scenarios, one with crude oil at $20/barrel and one at $15/barrel, were compared to the AGA-TERA Base Case oil price of $25 per barrel. In the analysis, prices for the portion of natural gas that is market responsive (70 percent) were assumed to decline at the same rate as crude oil, maintaining a level of 50 percent of the price of crude oil on a Btu basis. (The 50 percent level was selected after an examination of 1985 spot and contract prices that showed, on a Btu basis, natural gas varying between 42 and 53 percent of the price of crude. Subsequent model runs that showed consistency in supply and demand at this level supported this selection). The results of the simulation are listed below.

U.S. Average Field Acquisition Cost of Natural Gas
(Constant 1985 $/MCF)

Year	Base Case: $25/barrel	$20/barrel	$15/barrel
1985	2.58	2.58	2.58
1986	2.14	1.88	1.59
1987	1.90	1.66	1.37
1988	1.91	1.68	1.38
1989	1.93	1.69	1.39
1990	1.94	1.69	1.39

The results show that by 1990, a 20 percent decrease in the price of crude oil (from $25 to $20/barrel), will be associated with a 13 percent decrease in the field acquisition cost of natural gas, for a cross-elasticity of 0.64. The price responsiveness of natural gas appears to be even higher in the case of crude oil at $15/barrel, where the 40 percent decrease in the price of crude oil (from $25 to $15/barrel) leads to a 28 percent decrease in the price of natural gas, for a cross-elasticity of 0.71. AGA assumes that because natural gas is a regulated industry, all of these price decreases will be passed on to consumers.

At the retail level the cross-elasticity is somewhat reduced. This is because, while the savings in dollar terms are at least as great for retail prices as for field acquisition costs, in percentage terms they are smaller, since other costs (e.g., transportation and storage) will not be effected by lower oil prices. The results show that by 1990, a 20 percent decrease in the price of oil (from $25 to $20/barrel) will be associated with a 7 percent decrease in the price of natural gas for industrial users, for a cross-elasticity of 0.35. In the case of oil at $15/barrel, the cross-elasticity is 0.41 as shown in the following figure:

U.S. Average Industrial Retail Natural Gas Prices
(Constant 1985 $/MCF)

Year	Base Case: $25/barrel	$20/barrel	$15/barrel
1986	4.02	3.73	3.44
1987	3.74	3.48	3.16
1988	3.72	3.46	3.13
1989	3.70	3.44	3.09
1990	3.75	3.48	3.13

In the long term, the TERA model analysis indicates potential supply problems if oil prices remain low. As long as crude prices are low, exploratory drilling is reduced. Projected reserve additions over the period 1986 and 1990 are 6.2 percent and 17.0 percent less in the $20/barrel and $15/barrel scenarios, respectively, than in the $25 base case, exerting upward pressure on prices in the long-term.

Other Analyses

A 1986 study by the Congressional Budget Office comparing the prices of natural gas and crude oil found that a 1 percent increase (or decrease) in the price of crude was associated with, over a 3-year period, a 0.30 percent increase (or decrease) in the price of natural gas at the retail level. The relationship was calculated using 15 years of energy price data, adjusted for inflation, and a three year distributed lag model that projected the price of natural gas as a function of the price of crude and of GNP. The three-year lag in the CBO assessment differs from the AGA analysis, which assumes price adjustments for natural gas take place entirely in the same year as the change in price for crude oil. The CBO analysts are familiar with the AGA work and believe that its projections that natural gas prices will decline at the same rate as crude oil are optimistic. However, they also note that their own forecasts are based on a set of historical data that, due to decontrol and other changes in the natural gas industry, may not provide a realistic picture of the current relationship between crude oil and natural gas prices.

A third study of the relationship between crude oil and natural gas markets was performed by the U.S. Department of Energy's Information Administration. In the EIA study, EIA energy models were used to estimate the effects on energy markets and the U.S. economy of crude oil prices that decline from $27/barrel in 1985 to $13/barrel in 1986, then rise to $17/barrel in 1990 and $20/barrel by 1995 due to large demand pressures (1985 dollars). The results are compared to an EIA base case prediction in 1985 that showed 1985 and 1990 crude oil prices at $27/barrel and 1995 prices of $30/barrel. Base case predictions of natural gas prices, at the wellhead, called for prices of $2.60 (MCF) in 1985, $2.58 in 1990, and $3.93 in 1995. With the reduced oil prices, natural gas prices would fall to $1.96/MCF in 1990 and rise to $3.50/MCF in 1995 (Table 3). The $0.62 difference in natural gas prices with crude at $27/barrel versus $17/barrel in 1990 is reduced to $0.43 in 1995 by the reduced supplies of natural gas associated with low prices for crude.

	Crude Oil Prices		Natural Gas Wellhead Prices ($/MCF)	
Year	Base Case	Lower Oil Case	Price Scenario	Base Case
1985	$27.00	$27.00	$ 2.60	$ 2.60
1990	$27.00	$17.00	$ 2.58	$ 1.96
1995	$30.00	$20.00	$ 3.93	$ 3.50

All three studies point to a decline in natural gas prices to accompany a decline in oil prices. Estimates of the decline in natural gas prices at the retail level range from 0.30 percent to 0.41 percent for each 1 percent decrease in the price of natural gas through 1990. At the wellhead, the estimates range from 0.65 to 0.71 percent reductions in natural gas prices for each 1 percent reduction in crude oil prices. Both studies that consider post-1990 prices expect upward pressure on natural gas prices relative to crude oil prices after 1990 due to supply considerations. However, prices will likely remain lower than they would have been without the reduced oil prices.

RELATIONSHIP BETWEEN CRUDE OIL AND METHANOL PRICES

The previous section described the relationships between crude oil prices and natural gas prices and provided a procedure to adjust gas price expectations based on an expected change in crude oil prices. The change in gas prices will, in turn, change the cost of gas inputs to methanol production if those costs are assumed to include more than a zero opportunity cost for natural gas. The percentage of cost of methanol production that is associated with the natural gas production varies with both gas prices and the prices of all other inputs. In general, gas costs are from five to fifteen percent of the delivered methanol variable cost. Combining this relationship with the cross-price elasticity calculated in the previous section, yields the following procedure for calculating methanol production price (cost) changes as a result of crude oil price changes. The percent change in methanol prices is equal to .07 times the percent change in the price of crude oil. This is based on the oil-gas cross-price elasticity of .7 and a ten percent share of delivered methanol cost associated with gas cost. This relationship is most appropriate for current methanol supply scenarios which are based on average variable cost pricing. Future prices will be less affected by gas price changes as gas cost will be a smaller portion of a full cost recovery price.

PETROLEUM PRICES

Crude oil prices are given for four separate scenarios in Exhibit A-1. The DOE scenario is taken from the 1986 publication National Energy Policy Plan: Projections to 2010 (DOE/PE-0029/3). The data were developed using the WOIL: World Energy Model supplemented by the analysis and judgement of DOE staff. Data for the three other forecasts were provided by the CEC. All series have been converted to 1985 dollars using the implicit price deflater for GNP.

Diesel and gasoline estimates were also provided by DOE staff and are unpublished revisions to data in The National Energy Policy Plan. Diesel data are based on a linear relationship between diesel and crude prices. Gasoline data are based on a slightly non-linear relationship. These relationships were used to determine a diesel or gasoline value for each given crude value.

The DOE diesel and gasoline estimates were then used to trend 1985 diesel, premium and unleaded prices for California. The DOE gasoline estimates were used to trend both premium and unleaded prices. The 1985 California prices were taken from the CEC Quarterly Oil Report for the first quarter of 1986. These data represent weighted average wholesale prices before taxes as reported by California refiners on DOE from EIA-782A. Annual prices are based on a simple unweighted average of monthly prices. The No. 2 distillate prices was used for diesel prices.

EXHIBIT A-1:
PETROLEUM PRICE SCENARIOS
(Wholesale Price, 1985 $)

		$ Per Barrel Crude Oil	Cents Per Gallon		
			Diesel	Unleaded Regular	Unleaded Premium
U.S. Department of Energy	85	28.99	75.3	86.3	93.1
	90	24.54	67.1	80.5	86.8
	95	31.93	80.7	90.1	97.2
	2005	50.30	114.7	119.1	128.5
California Low	85	28.99	75.3	86.3	93.1
	90	19.50	57.8	73.9	79.8
	95	21.11	60.8	75.9	81.9
	2005	27.02	71.8	83.7	90.3
California Medium	85	28.99	75.3	86.3	93.1
	90	26.72	71.2	83.4	89.9
	95	29.19	75.7	86.5	93.3
	2005	37.37	90.8	98.1	105.8
California High	85	28.99	75.3	86.3	93.1
	90	41.14	97.8	103.9	112.1
	95	32.23	83.2	92.0	99.3
	2005	42.55	104.4	106.2	114.6