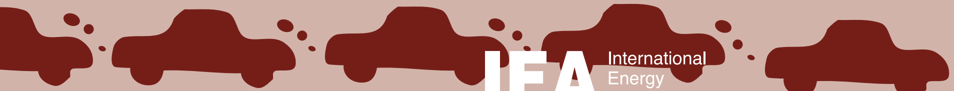
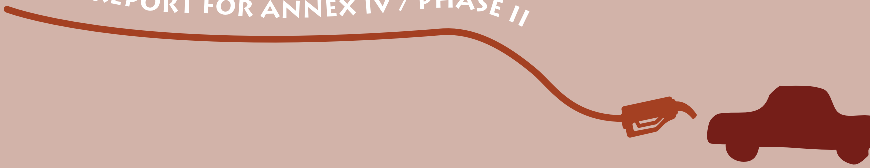


International Energy Agency

PROGRAM OF RESEARCH AND DEVELOPMENT ON ALTERNATIVE MOTOR FUELS / IEA ALTERNATIVE MOTOR FUELS AGREEMENT

PRODUCTION OF ALCOHOLS AND OTHER OXYGENATES FROM FOSSIL FUELS AND RENEWABLES

FINAL REPORT FOR ANNEX IV / PHASE II



Natural Resources Canada
Ressources naturelles Canada

Canada

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PRODUCTION OF
ALCOHOLS AND OTHER OXYGENATES
FROM
FOSSIL FUELS AND RENEWABLES

Final Report
for
Annex IV/Phase II

July 1995

IEA IMPLEMENTING AGREEMENT
ON ALTERNATIVE MOTOR FUELS

PRODUCTION OF ALCOHOLS AND OTHER OXYGENATES FROM FOSSIL FUELS AND RENEWABLES

Final Report for Annex IV/Phase II

INTRODUCTION

Annex IV of the International Energy Agency (IEA) Implementing Agreement on Alternative Motor Fuels commenced on October 24, 1986 and was proposed to be in operation for a period of 36 months.

The purpose of Annex IV was to exchange recent information on the production of alcohols and other oxygenates between the participating countries, and to review various production methods with the view to identifying potential areas of future development and cooperative research programs. Although the Annex, as originally designed, was supposed to cover the production of alcohols and other oxygenates only from fossil fuels, a number of contributions addressed their production from renewables. This development has expanded the scope of work to some extent.

Over the 36 months period, the Operating Agent, the Department of Energy, Mines and Resources Canada, issued four reports. These reports were tabled at the 6th, 7th, 8th and 10th Executive Committee meetings of the Agreement and were approved by this committee.

The Final Report of Annex IV was published in June 1990. The report was divided into three parts, as follows:

a) Introduction, containing a brief description of the Annex and the list of participants;

b) Part I, containing the Operating Agent's Report; and

c) Part II, containing the summary of contributions submitted by participating countries, arranged by topic.

This report had contributions from all six countries participating in the Annex (and the Agreement): Canada, Italy, Japan, New Zealand, Sweden and the United States.

At the meeting of June 7–10, 1989, the Executive Committee of the Agreement expressed its desire to continue operation of this Annex, past the October 1989 deadline imposed at the beginning, with cost-sharing between the participating countries. This extension of Annex IV is referred to as Phase II. The Operating Agent of the Annex was asked to prepare a proposal for the continuation of the annex, for consideration at the November 16–17, 1989 meeting of the Executive Committee.

MANDATE FOR ANNEX IV/PHASE II

The Executive Committee provided the following instructions to the Operating Agent regarding the mandate for Annex IV/Phase II:

> The Annex should examine:
>
> - The availability of methanol feedstocks around the world. This refers primarily to natural gas, and would entail a survey of reserves, the cost of extraction and transportation. This aspect was not covered in the California Fuel Methanol Study, performed by Bechtel Inc.;
> - The production of methanol and ethanol from biomass;
> - Greenhouse gas emissions from methanol and ethanol production processes.
>
> The definition of Annex IV/Phase II should take into account the R&D directions given in the IEA study on the Diversification of Transport Fuels.
>
> The proposal for this phase of Annex IV should be circulated one month before the next Executive Committee, defining the study parameters and the level of effort required.

The Operating Agent responded with a proposal, which was discussed at the Executive Committee meeting of November 17, 1989. The Executive Committee approved the following program of work for Annex IV/Phase II:

1. The next phase of Annex IV to be in effect for a period of 24 months.
2. The Annex to be performed in cost-shared fashion, with a contribution of $40K (U.S.) from each participating country.

3. The agenda of work to include:

   - An evaluation of the economics of natural gas supply, demand and price;
   - An economic comparison of LNG, methanol and synthetic distillate;
   - An evaluation of the economics of methanol and ethanol supply from biomass; and,
   - An evaluation of greenhouse gas emissions from methanol and ethanol production processes.

   These studies would be performed by contract, with the work overseen by a Steering Committee. The Operating Agent would be responsible for detailed supervision. The selected contractors would also be required to present the results at meetings of the Executive Committee. The reports would be available in sufficient quantities to satisfy the requirements of each participating country.

Part I

The Operating Agent's Report

BACKGROUND

The strategic need for replacing petroleum derivatives in transportation and environmental concerns related to the use of gasoline octane additives and gasoline/diesel exhaust emissions has led to investigation of the potential for replacing petroleum derivatives partly or totally by alternative fuels. In order to increase the penetration of alternative fuels, especially alcohols as motor fuel, there is a need for establishing optimum methods for fuel alcohol production, applicable to various countries and to different feedstocks. An exchange of information on alcohol production methods and an analysis of the various developments in the field of alcohols synthesis was felt necessary for that purpose. To perform this work, this Annex, which is part of the Implementing Agreement on Alternative Motor Fuels, was proposed and endorsed by the Executive Committee of the Agreement on October 24, 1986.

Following the completion of the Phase I study, and the publication by the Operating Agent of the Final Report, the Executive Committee of the Agreement felt that it was desirable to continue the operation of Annex IV in a Phase II study, in cost-shared mode. As described in the Mandate section, this phase was necessary to cover international developments in natural gas, the economic evaluation of methanol and ethanol production from biomass and environmental aspects related to the production of alcohols from a variety of feedstocks.

The Operating Agent arranged for the performance of the following studies:

1. **"Natural Gas Supply, Demand and Price"**, contracted to Jensen Associates, Inc. of Boston, Massachusetts;
2. **"Economic Comparisons of the LNG, Methanol and Synthetic Distillate"**, contracted to Jensen Associates, Inc. of Boston, Massachusetts;
3. **"A Comparison of the Production of Methanol and Ethanol from Biomass"**, contracted to TDA Research, of Wheat Ridge, Colorado; and,

4. **“Greenhouse Gas and Other Emissions to Air Resulting from Ethanol and Methanol Use as Alternative Fuels”**, contracted to Ortech International, of Mississauga, Ontario.

All these studies are available from the Operating Agent at the address given below:

Dr. Liviu Vancea
Chief, Environmental Assessment
Office of Environmental Affairs
Department of Energy, Mines and Resources Canada
580 Booth Street
Ottawa, Ontario
Canada, K1A 0E4

Telephone 613-994-3866; telefax 613-995-5719.

The following pages provide summaries of these four studies, as follows:

Study	**Summarized in**
Natural Gas Supply, Demand and Price	Part II
Economic Comparisons of the LNG, Methanol and Synthetic Distillate	Part III
A Comparison of the Production of Methanol and Ethanol from Biomass	Part IV
Greenhouse Gas and Other Emissions to Air Resulting from Ethanol and Methanol Use as Alternative Fuels	Part V

The conclusions derived from these studies and recommendations of the Operating Agent are presented in Part VI.

Part II

Summary of the Natural Gas Supply, Demand and Price Study

October 1990

Study performed by:
Jensen Associates, Inc.
Boston, Massachusetts

NATURAL GAS SUPPLY, DEMAND AND PRICE

INTRODUCTION

Much of the recent work on the economics of methanol and other alternative fuels use has focused on the costs of manufacturing plants, distribution systems, vehicles, and on the environmental impact of these fuels.

In many of the existing studies, the authors have simply examined the location of proven gas reserves country-by-country, and then assumed gas would be available as feedstock at some hypothetical price — \$0.50/MMBtu, \$1.00, \$1.50 and so on — based on the need for local infrastructure or the availability of a local gas market. In particular, much attention has been focused on the potential availability of vented and flared gas at virtually no cost to the methanol plant.

Currently, the largest chemical methanol plants have an operating capacity of about 2,500 tonnes/day. A large-scale methanol fuel facility as presently envisaged by the major oil companies would comprise four such plants in a single complex producing 10,000 tonnes/day, or 80,000 barrels per day (b/d) of methanol. A single-train “advanced technology” plant of the same size has also been postulated by some observers.

In either case, the facility would have a feedstock requirement of roughly 300 million cubic feet per day (MMcfd) of natural gas. Thus, the feedstock requirement of the methanol facility would be similar to that of a single 2 million tonne per year (MMt/year) liquefied natural gas (LNG) train.

In LNG trade, it is usually assumed that a new LNG export plant requires at least two trains, but more likely three, to be economically viable. Thus, while a methanol fuel complex is about four times the size of a large, new chemical installation, it is about one-third the size of a new LNG plant.

Over a 20-year life, a methanol fuel plant would require about 2.5 trillion cubic feet (Tcf) of gas. To judge from proven reserves figures, there seems to be little reason to question the availability of natural gas feedstock. Not all of the gas reserves are uncommitted or accessible, however, and a large proportion of those that might be classified as an exportable surplus are concentrated geographically.

OBJECTIVES OF THE STUDY

To identify where uncommitted gas reserves are available; what the cost of supplying the gas to a methanol fuel plant is likely to be, given the IEA's projected oil prices; and how the economics of transporting gas to markets as LNG, pipeline gas, and methanol compare.

WORLDWIDE NATURAL GAS SUPPLY

Although the world's proved reserves of natural gas contain only 80 percent as much energy as the total proved reserves of liquid hydrocarbons, there is reason to believe potential gas reserves are currently understated. In many parts of the world, hydrocarbon exploration is "gas prone". In regions that already have large gas reserves relative to foreseeable markets there is little reason to continue exploring. However, if gas markets were to develop, there is little doubt substantial additional gas could be found from increased exploration activity.

Even existing gas reserves are less well developed than those of oil. Although gas reserves contain 45 percent of the energy in the world's proved hydrocarbon reserves, gas accounts for only 35 percent of the total hydrocarbon consumption. The major reason for this is natural gas transportation is very costly compared to oil transportation. As a result, only 13 percent of the world's natural gas production ever leaves its country of origin. Similarly, natural gas accounts for only 14 percent of the total international trade in hydrocarbons, with movements of liquefied natural gas (LNG) by tanker accounting for less than 4 percent of total world tanker trade.

The high cost of gas transportation sets it apart from oil as an energy commodity, making the commercial value of gas discoveries very dependent on how far they are from markets. Over the past decade the world has added nearly three and a half times as much gas to its proved reserves as it has consumed. But many of these reserves are in locations, such as western Siberia in the Soviet Union or in the Middle East, where growth in local markets is not keeping pace with discoveries, and where export markets are costly to reach. Figure I-1[1] shows the geographic pattern of gas consumption in 1988 compared to average annual reserve additions over the past decade. The surplus of gas in the U.S.S.R., the Middle East and Africa is apparent.

Since many of these remote gas reserves are substantially underutilized, they represent a large pool of potential raw material for fuel methanol production,

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[1] All Figures and Tables appear at the end of each section.

as well as for pipeline or LNG export. Because methanol is comparatively inexpensive to transport over long distances by tanker, the economics of its production are less sensitive to distance than those of pipeline gas or LNG. Consequently, a fuel methanol supplier has a great deal of latitude to seek out low cost gas feedstock anywhere in the world.

OCCURRENCE OF NATURAL GAS

Natural gas occurs in oil reservoirs as associated gas. It may be in solution in the oil, but often is contained in gas caps overlying the oil pool as well. Gas also occurs in non-associated gas reservoirs. Sometimes such reservoirs contain a light crude-oil-like material known as gas condensate. Seventy-three percent of the world's gas reserves are non-associated.

The production of non-associated gas is discretionary since it need not be developed if there is not an attractive market for it. The production of associated gas on the other hand is often not discretionary. Solution gas is produced along with the oil and separated at the surface. If it has no market, it may be conserved at some cost by reinjecting it into the oil reservoir or it may simply be flared.

Much of the gas that is being flared throughout the world is scattered and cannot be gathered easily for feedstock use. Table I-1 summarizes flared gas production in 1988. Even countries with well established gas markets, such as the U.S. or the U.K. still have significant quantities of flared gas, suggesting the marginal economic value of much of this production. However, as the table demonstrates, the amount of gas flared in an entire country is usually not large compared to the 300 million cubic feet per day (MMcfd) of feedstock that would be required by a single 10,000 tonne per day methanol fuel plant.

MARKET STATUS OF RESERVES

Since 1977 Jensen Associates has been making annual estimates of the market status of world gas reserves in order to identify large blocks of good quality reserves potentially available for export. The methodology classifies reserves into six market categories. Two categories reflect existing commitments to domestic and export markets; two comprise "deferred" and "frontier" reserves whose commercialization is delayed; and two cover surplus gas that is marginal or exportable. Estimates for 1988 are summarized in Figure I-2 and Table I-2. The summary estimates contained in Figure I-2 and Table I-2 are based on detailed country-by-country analysis. Exportable surpluses are shown in Figures I-4, I-5 and I-6.

Gas committed for export is straightforward. It is simply the sum total of gas to be delivered over the life of export contracts. Gas committed to domestic markets may refer to local gas production in countries that on the margin are importers, such as the U.S. and West Germany. In countries such as Canada and the Netherlands which are substantial exporters, the domestic commitment refers to some level of domestic set-aside which must be maintained for the exporting country to feel secure before making new export commitments.

Where the commercialization of reserves is delayed they are classified as “deferred” or “frontier” gas. The frontier category is used to describe high quality, but remote reserves in countries with well developed gas grids.

Deferred gas refers to reserves whose production is determined by oil reservoir considerations that limit the flexibility the seller has to commit the gas to market outlets. It may be gas contained in a gas cap and currently unavailable for market, or gas undergoing injection for oil field pressure maintenance. Or it may simply reflect the fact that solution gas production in a country where associated gas predominates, such as Saudi Arabia or Kuwait, will not be available for market if the oil production levels do not permit it.

The final two categories are both surplus to foreseeable commitments. The separation of this surplus gas into “exportable” and “marginal” categories reflects a country-by-country judgment as to whether the gas reserve is sufficiently large and well placed to support international gas trade. By these definitions, 43 percent of the world’s proved gas reserves can be considered as “exportable surplus”.

Just four countries — the U.S.S.R., Iran, Abu Dhabi, and Qatar — account for 75 percent of the world’s exportable gas surplus. But a number of others have large enough blocks of exportable reserves for gas export projects to be under active consideration. In order of exportable reserve size, they include Nigeria, Norway, Australia, Indonesia, Algeria, Malaysia, Venezuela, and Trinidad.

Several other countries have also been mentioned at some time as possible locations for LNG exports. They include Argentina and Bangladesh, for example. However, because their reserves are comparatively small and are remote from major LNG markets, they are not being actively pursued. Nevertheless, they may be candidates for future methanol fuel plants.

Table I-1

WORLDWIDE GAS FLARING
1988

	BCFD	Methanol Complex Equivalents[1]
U.S.S.R.	1.93	6.4
Nigeria	1.18	3.9
Algeria	0.58	1.9
Iraq	0.44	1.5
Indonesia	0.42	1.4
U.S.	0.39	1.3
Iran	0.39	1.3
India	0.38	1.3
Venezuela	0.35	1.2
Trinidad	0.34	1.1
Saudi Arabia	0.32	1.1
Canada	0.26	0.9
Libya	0.25	0.8
U.K.	0.22	0.7
Argentina	0.19	0.6
All Other	1.30	4.3
WORLD TOTAL	**8.94**	**29.8**

[1] Methanol Complex Equivalents at 300 MMcfd feedstock requirements.

Table I-2

WORLD PROVED RESERVES — 1988

Tcf

Region	Proved Reserves	Committed		Delayed		Surplus	
		Domestic	Export	Deferred	Frontier	Exportable	Marginal
NORTH AMERICA							
OECD	286.9	182.6	16.8	30.1	14.4	39.7	3.3
EUROPE							
OECD	200.0	78.8	45.2	6.8	0.0	66.5	2.7
U.S.S.R	1500.0	481.8	62.0	0.0	0.0	836.2	120.0
Other East	29.0	28.6	0.0	0.0	0.0	0.0	0.4
ASIA-PACIFIC							
OECD	78.0	22.6	5.7	0.2	0.0	45.8	3.7
Indonesia	83.6	9.5	29.8	3.1	0.0	39.5	1.7
Non-OPEC Developing	134.4	46.9	6.5	0.0	0.0	50.3	30.7
China	31.7	9.7	0.0	0.0	0.0	0.0	22.0
LATIN AMERICA							
OPEC	106.2	14.0	0.0	73.0	0.0	16.8	2.4
Non-OPEC Developing	134.5	44.1	0.3	50.1	0.0	34.1	5.9
AFRICA							
OPEC	215.5	40.8	28.3	25.0	0.0	104.1	17.3
Non-OPEC Developing	32.2	10.7	0.0	0.8	0.0	6.7	14.0
MIDDLE EAST							
OPEC	1146.2	85.1	2.9	461.8	0.0	482.9	113.5
Non-OPEC Developing	21.0	7.6	0.0	2.3	0.0	0.0	11.1
TOTAL WORLD	**3999.2**	**1062.8**	**197.5**	**653.2**	**14.4**	**1722.6**	**348.7**

Table I-3

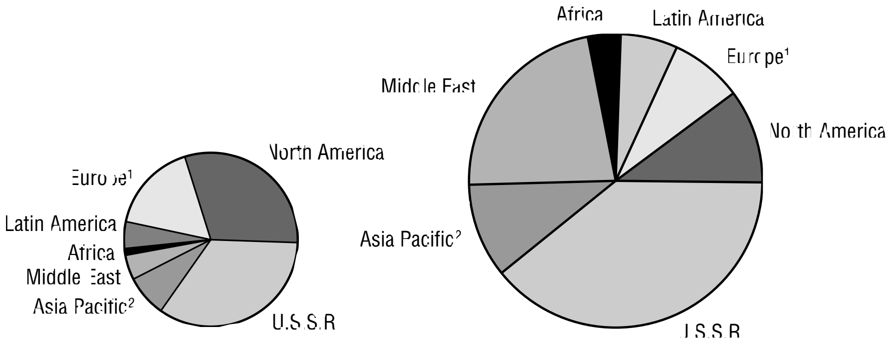
PROVED GAS RESERVES AND EXPORTABLE SURPLUSES

As of December 31, 1988
Tcf

	Proved Reserves	Exportable Surplus
U.S.S.R.	1,500	836
Iran	494	160
United States	193	26
Abu Dhabi	183	154
Qatar	157	152
Saudi Arabia	146	8
Algeria	104	34
Venezuela	102	13
Iraq	95	8
Canada	94	14
Norway	88	55
Nigeria	85	68
Indonesia	84	40
Mexico	73	6
Australia	71	46
Netherlands	62	9
Malaysia	52	28
Kuwait	42	0
China	32	0
Argentina	27	12
Libya	26	3
India	23	0
United Kingdom	22	0
Pakistan	18	0
Trinidad	17	12
Other Middle East	49	0
Other Asia Pacific	48	22
Other Europe	57	2
Other Latin America	22	8
Other Africa	33	7
TOTAL WORLD	**3,999**	**1,723**

Figure I-1

WHERE GAS IS CONSUMED   WHERE IT IS BEING FOUND



1988
World Consumption
69.16 Tcf

1979 – 1988
Average Annual
Reserve Additions
203.94 Tcf

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[1] Includes Eastern Europe
[2] Includes China and Japan

Figure I-2

MARKET STATUS OF WORLD PROVED GAS RESERVES

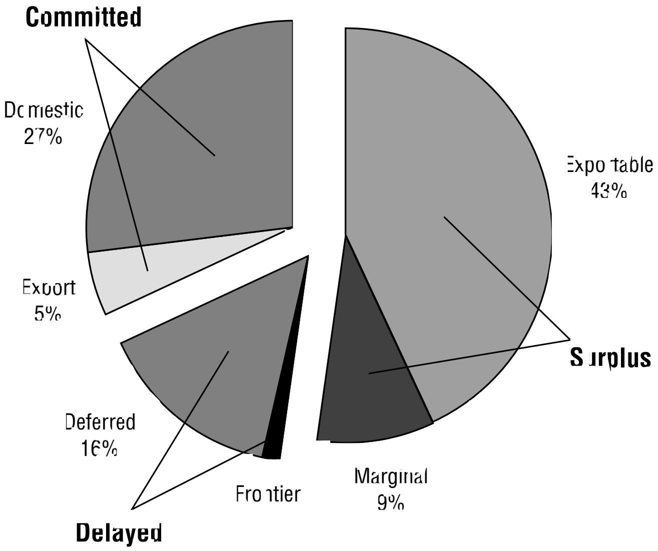

Figure I-4

PROVED RESERVES AND EXPORTABLE SURPLUSES
December 31, 1988
Tcf

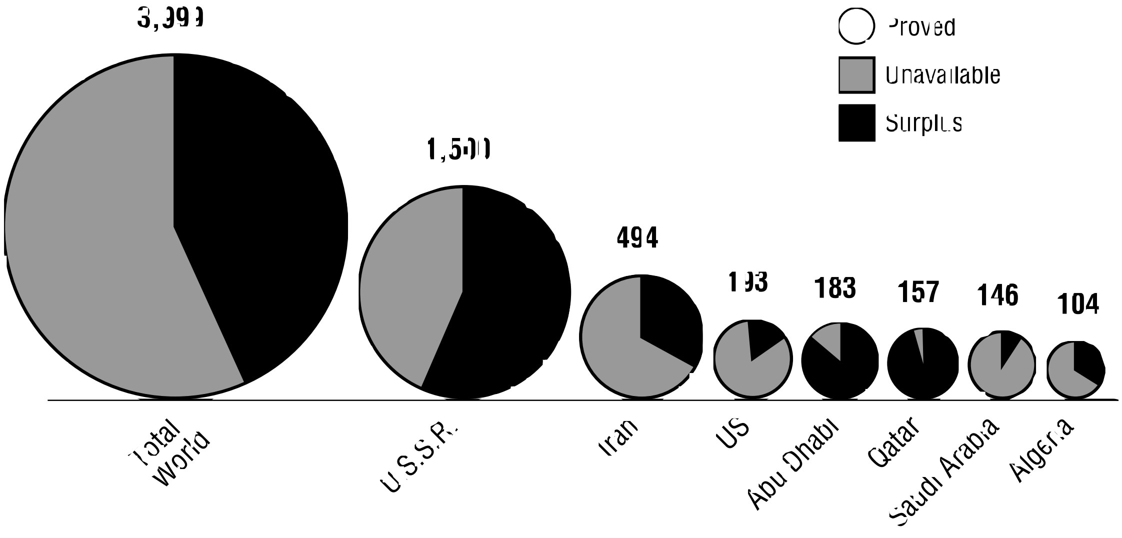

Figure I-5

PROVED RESERVES AND EXPORTABLE SURPLUSES
December 31, 1988
Tcf

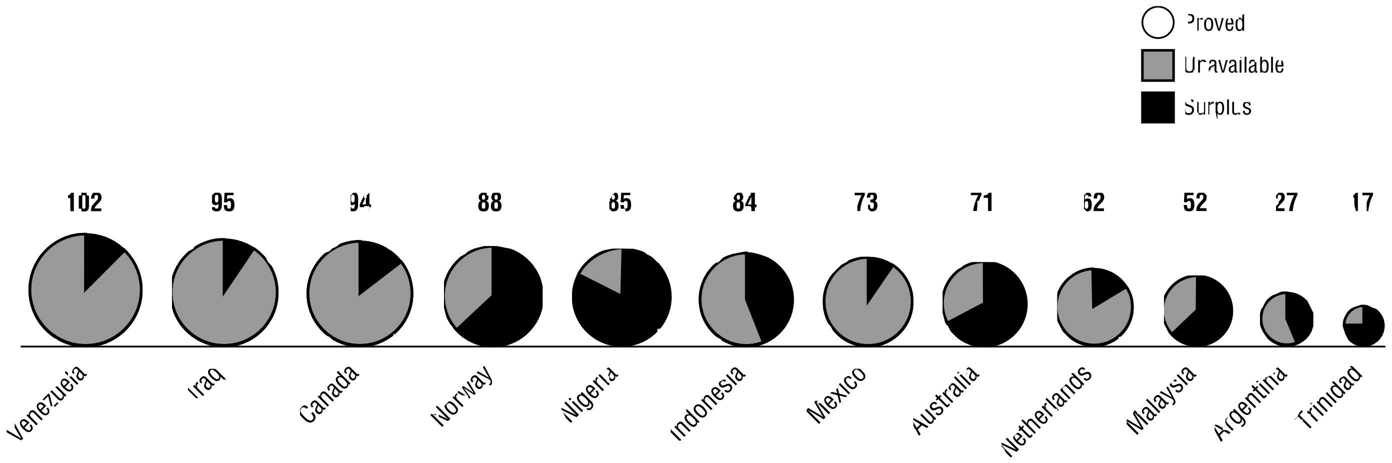

Figure I-6

MAJOR UNCOMMITED GAS RESERVES EXPORTABLE TO WORLD MARKETS
December 31, 1988

Total world exportable surplus 1,723 Tcf
including 90 not shown here.

NATURAL GAS CONSUMPTION

Given the apparent availability of gas feedstock, it would be misleading to imply a reserve of 3 or 4 Tcf is all that is needed to support a methanol fuel plant. The most important constraint is that the gas reserve must provide a predictable and reliable supply of feedstock over the life of the plant so the operation will be unimpaired. The problem, however, is that the search for suitable feedstock for methanol plants, like the search to support LNG exports, is less a question of volume — which is plentiful — than it is a question of price.

Where gas has reached commodity status, in North America for example, the price charged to a methanol plant will be determined by the going market rate. The same is true elsewhere in developed gas markets. However, relative to the price of oil and other fuels, the pattern of gas price formation differs from one region to another.

In Japan, gas imported as LNG was used to displace oil and the country is now heavily dependent on it for power generation. In view of this, it was reasonable to tie the gas import price directly to the price of oil. In doing so, however, the early deals effectively locked-in the margins that would go to the LNG producer, shipper, and importer in later trades. Currently, imported LNG is priced on the basis of cif[2] parity per MMBtu with crude oil. Although there may be some slippage in the share of the oil price captured by LNG, the direct link to oil is likely to remain.

In Europe, the development of gas trade increased substantially after the discovery of the Groningen field in the Netherlands in 1959. Although there is locally produced gas in many European countries, in all, (except for the major producers, the Netherlands, Norway and the U.K.) it represents less than half of local consumption. Thus on the margin, the major import supply contracts from Algeria, the Netherlands, Norway and the U.S.S.R., have tended to establish the level of gas prices for European markets. These prices have often been negotiated between governmental buyers and sellers and thus, like the Japanese contracts, tend to be administered, rather than market prices. Commonly, the contracts have been based on oil price relationships, and although there has been some effort to introduce coal-competitive elements, there is a strong expectation for prices to remain oil-related.

The U.S. gas market was once price-regulated but has been moving toward a system of market-responsive pricing at the wellhead and open transportation

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[2] Cif stands for cost, insurance and freight paid, and basically refers to the landed price. In this case, price parity is established according to the heating value (Btu content) of LNG and crude oil.

to promote competition at the burner-tip. While it has appeared that competition in dual-fired boilers would keep gas prices linked to residual fuel oil prices, increasingly stringent pollution controls, and technological improvements in favor of gas use in combined cycle power plants, for example, have reduced the degree to which gas competes with fuel oil. Consequently, if market demand for gas rises more quickly than low-cost supply, as seems likely, gas prices may rise faster than oil prices.

Gas accessible to one of the major markets, either by pipeline as in Canada or Mexico, or as LNG, will be priced on a market netback basis. Elsewhere, gas prices are established by the producer-country government, taking into account its perception of the value of the resource and the role of gas in the nation’s development. In Trinidad, for example, gas produced offshore is purchased by the government, transported across the island, and sold at different prices to various categories of consumers. In a third case, where market and government selling prices have not been established, gas reserves may be developed on the basis of project economics, including the host government take.

Since there is no precedent for setting prices in many of these locations, there is usually a complex set of negotiations with ultimate buyers to establish some form of reference price and then between venture partners and the host government to determine how the revenues are to be shared. Gas development costs, while an important element in determining project feasibility, do not necessarily dictate the ultimate selling prices.

Table II-1 provides detailed country-by-country estimates of production, consumption and trade in 1988.

Table II-1

Natural Gas Production, Consumption and Trade — 1988
Tcf

	Gross Production	Re-Injected	Flaring, Losses	Marketed Production	Pipeline[1] Imports	LNG[1] Imports	Consumption	Residential Commercial	Industrial	Power	Field Uses
NORTH AMERICA OECD											
United States	20.49	2.45	1.36	16.68	1.25	(0.03)	17.90	7.27	6.30	2.63	1.70
Canada	4.61	0.54	0.60	3.47	(1.25)	0.00	2.21	0.83	0.94	0.06	0.38
Subtotal	25.11	2.99	1.97	20.15	0.00	(0.03)	20.12	8.10	7.24	2.69	2.09
EUROPEAN OECD											
Germany	0.62	0.00	0.03	0.59	1.46	0.00	2.05	0.92	0.73	0.33	0.07
U.K.	1.88	0.09	0.17	1.61	0.40	0.00	2.02	1.31	0.53	0.02	0.16
Netherlands	2.33	0.00	0.00	2.33	(0.94)	0.00	1.39	0.64	0.40	0.33	0.02
Italy	0.59	0.00	0.00	0.59	0.87	0.01	1.47	0.60	0.57	0.28	0.01
France	0.16	0.00	0.05	0.11	0.58	0.32	1.01	0.53	0.45	0.01	0.01
Belgium	0.00	0.00	0.00	0.00	0.20	0.10	0.30	0.14	0.13	0.03	0.00
Yugoslavia	0.11	0.00	0.00	0.11	0.17	0.00	0.28	0.03	0.17	0.03	0.06
Austria	0.04	0.00	0.00	0.04	0.14	0.00	0.18	0.06	0.07	0.04	0.01
Spain	0.03	0.00	0.00	0.03	0.00	0.11	0.15	0.03	0.11	0.01	0.00
Norway	1.27	0.16	0.05	1.05	(1.00)	0.00	0.06	0.00	0.00	0.00	0.06
Denmark	0.19	0.09	0.01	0.08	(0.03)	0.00	0.06	0.03	0.02	0.00	0.00
Other	0.08	0.00	0.00	0.08	0.18	0.00	0.25	0.06	0.12	0.07	0.01
Subtotal	7.29	0.34	0.32	6.63	2.02	0.54	9.19	4.35	3.28	1.13	0.43

---

[1] A negative number denotes a net export.

.Table II-1 (continued)

Natural Gas Production, Consumption and Trade — 1988
Tcf

	Gross Production	Re-Injected	Flaring, Losses	Marketed Production	Pipeline[1] Imports	LNG[1] Imports	Consumption	Residential Commercial	Industrial	Power	Field Uses
ASIA PACIFIC OECD											
Japan	0.07	0.00	0.00	0.07	0.00	1.48	1.55	0.36	0.14	1.02	0.04
Australia	0.54	0.00	0.05	0.50	0.00	0.00	0.50	0.09	0.24	0.12	0.06
New Zealand	0.21	0.03	0.02	0.16	0.00	0.00	0.16	0.01	0.05	0.05	0.05
Subtotal	0.83	0.03	0.07	0.73	0.00	1.48	2.21	0.46	0.42	1.20	0.14
Total OECD	**33.22**	**3.37**	**2.35**	**27.51**	**2.02**	**1.99**	**31.52**	**12.82**	**10.87**	**5.16**	**2.67**

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[1] A negative number denotes a net export.

Table II-1 (continued)

Natural Gas Production, Consumption and Trade — 1988
Tcf

	Gross Production	Re-Injected	Flaring, Losses	Marketed Production	Pipeline[1] Imports	LNG[1] Imports	Consumption	Residential Commercial	Industrial	Power	Field Uses
LATIN AMERICA NON OPEC											
Mexico	1.27	0.00	0.35	0.92	0.00	0.00	0.93	0.03	0.57	0.11	0.21
Argentina	0.80	0.02	0.11	0.67	0.08	0.00	0.75	0.22	0.19	0.17	0.16
Trinidad	0.28	0.00	0.12	0.15	0.00	0.00	0.15	0.00	0.08	0.04	0.03
Other	0.76	0.23	0.12	0.42	(0.08)	0.00	0.34	0.02	0.17	0.09	0.06
Subtotal	3.12	0.24	0.70	2.17	0.00	0.00	2.17	0.26	1.04	0.41	0.46
AFRICA NON OPEC											
Egypt	0.30	0.02	0.04	0.24	0.00	0.00	0.24	0.00	0.09	0.15	0.01
Tunisia	0.03	0.00	0.02	0.01	0.03	0.00	0.04	0.00	0.01	0.03	0.00
Other	0.16	0.03	0.11	0.02	0.00	0.00	0.02	0.00	0.01	0.01	0.00
Subtotal	0.49	0.05	0.16	0.28	0.03	0.00	0.31	0.00	0.10	0.20	0.01
MIDDLE EAST NON OPEC											
Bahrain	0.26	0.05	0.01	0.19	0.00	0.00	0.19	0.00	0.12	0.07	0.00
Oman	0.16	0.07	0.01	0.09	0.00	0.00	0.09	0.02	0.02	0.03	0.02
Other	0.05	0.00	0.02	0.03	0.00	0.00	0.03	0.00	0.00	0.03	0.00
Subtotal	0.47	0.12	0.04	0.31	0.00	0.00	0.31	0.02	0.14	0.13	0.02

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[1] A negative number denotes a net export.

Table II-1 (continued)

Natural Gas Production, Consumption and Trade — 1988
Tcf

	Gross Production	Re-Injected	Flaring, Losses	Marketed Production	Pipeline[1] Imports	LNG[1] Imports	Consumption	Residential Commercial	Industrial	Power	Field Uses
ASIA PACIFIC NON OPEC											
Pakistan	0.44	0.00	0.00	0.44	0.00	0.00	0.44	0.07	0.24	0.13	0.01
Malaysia	0.59	0.00	0.01	0.58	0.00	(0.29)	0.29	0.00	0.06	0.05	0.17
India	0.46	0.00	0.15	0.31	0.00	0.00	0.31	0.00	0.24	0.06	0.00
Bangladesh	0.16	0.00	0.00	0.16	0.00	0.00	0.16	0.01	0.08	0.06	0.01
South Korea	0.00	0.00	0.00	0.00	0.00	0.09	0.09	0.01	0.00	0.09	0.00
Brunei	0.32	0.00	0.02	0.30	0.00	(0.26)	0.05	0.00	0.00	0.05	0.00
Taiwan	0.02	0.00	0.00	0.02	0.00	0.00	0.02	0.01	0.01	0.00	0.00
Thailand	0.21	0.00	0.02	0.19	0.00	0.00	0.19	0.00	0.00	0.18	0.01
Other	0.14	0.00	0.00	0.14	(0.08)	0.00	0.06	0.00	0.04	0.01	0.00
Subtotal	2.35	0.00	0.19	2.16	(0.08)	(0.45)	1.62	0.12	0.68	0.63	0.20
Total Non OPEC	**6.43**	**0.41**	**1.10**	**4.91**	**(0.05)**	**(0.45)**	**4.41**	**0.42**	**1.98**	**1.29**	**0.72**

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[1] A negative number denotes a net export.

Table II-1 (continued)

Natural Gas Production, Consumption and Trade — 1988
Tcf

	Gross Production	Re-Injected	Flaring, Losses	Marketed Production	Pipeline[1] Imports	LNG[1] Imports	Consump-tion	Residential Commercial	Indus-trial	Power	Field Uses
LATIN AMERICA OPEC											
Venezuela	1.34	0.42	0.22	0.69	0.00	0.00	0.69	0.02	0.29	0.16	0.23
Ecuador	0.03	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	1.36	0.42	0.24	0.70	0.00	0.00	0.70	0.02	0.29	0.16	0.23
AFRICA OPEC											
Algeria	3.88	1.87	0.42	1.58	(0.40)	(0.52)	0.66	0.06	0.06	0.23	0.30
Libya	0.44	0.14	0.11	0.19	0.00	(0.04)	0.16	0.00	0.04	0.08	0.03
Nigeria	0.65	0.08	0.43	0.13	0.00	0.00	0.13	0.00	0.01	0.10	0.02
Gabon	0.06	0.01	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	5.03	2.11	1.01	1.92	(0.40)	(0.56)	0.95	0.06	0.12	0.43	0.34
MIDDLE EAST OPEC											
Saudi Arabia	1.60	0.11	0.46	1.03	0.00	0.00	1.03	0.19	0.24	0.21	0.38
Iran	1.43	0.53	0.19	0.71	0.00	0.00	0.71	0.00	0.59	0.12	0.00
U.A.E	0.94	0.13	0.16	0.66	0.00	(0.11)	0.55	0.00	0.03	0.12	0.40
Kuwait	0.32	0.00	0.08	0.23	0.11	0.00	0.34	0.03	0.17	0.14	0.00
Qatar	0.26	0.00	0.03	0.23	0.00	0.00	0.23	0.00	0.07	0.13	0.02
Iraq	0.38	0.00	0.17	0.20	(0.11)	0.00	0.09	0.00	0.09	0.00	0.00
Subtotal	4.92	0.76	1.11	3.05	0.00	(0.11)	2.94	0.23	1.13	0.72	0.86

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[1] A negative number denotes a net export.

Table II-1 (continued)

Natural Gas Production, Consumption and Trade — 1988
Tcf

	Gross Production	Re-Injected	Flaring, Losses	Marketed Production	Pipeline[1] Imports	LNG[1] Imports	Consumption	Residential Commercial	Industrial	Power	Field Uses
ASIA PACIFIC OPEC											
Indonesia	1.83	0.31	0.17	1.34	0.00	(0.87)	0.47	0.00	0.35	0.01	0.12
Total OPEC	**13.14**	**3.61**	**2.53**	**7.01**	**(0.40)**	**(1.54)**	**5.06**	**0.30**	**1.88**	**1.32**	**1.56**
CENTRALLY PLANNED ECONOMIES											
U.S.S.R.	28.23	0.00	1.04	27.18	(3.02)	0.00	24.17	3.02	8.80	9.17	3.17
Eastern Europe	2.10	0.00	0.02	2.08	1.45	0.00	3.52	0.32	2.26	0.86	0.08
China	0.49	0.00	0.00	0.49	0.00	0.00	0.49	0.05	0.27	0.02	0.14
Total CPEs	**30.81**	**0.00**	**1.07**	**29.74**	**(1.57)**	**0.00**	**28.17**	**3.40**	**11.31**	**10.05**	**3.42**
TOTAL WORLD	**83.60**	**7.38**	**7.05**	**69.17**	**0.00**	**0.00**	**69.17**	**17.52**	**25.93**	**17.51**	**8.21**

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[1] A negative number denotes a net export.

GAS PRICE FORMATION

The price sellers charge a methanol fuel producer for gas feedstock will be determined in part by the nature of the particular gas source. Thus prices may be market-related, set by the host country, or project-based, although the three are inter-related.

Where gas has reached commodity status, as in North America for example, the price charged to the methanol plant will be the going market rate. While the market rate may differ from one region to another, the price to the methanol producer will remain tied to the market price of gas generally, regardless of the particular supply source that supports the plant.

In a number of developing countries, such as Trinidad and Bangladesh, a local gas grid has been developed to the point where the government sets specific selling prices for particular categories of gas use. While there may be somewhat greater flexibility in such countries to negotiate a favorable, project-specific gas price, gas development costs for a particular source of supply may still not be the dominant factor in determining the government selling price to a methanol plant.

For many locations where methanol production may be considered, there are no established gas markets. In such cases the gas price the buyer and seller ultimately negotiate will reflect a variety of factors. Among them are the costs of developing the gas reserves, the return on investment required by the seller, and the revenue taken by the government in the form of taxes, royalties, or project participation.

To estimate gas prices in major markets we have utilized two projections of cif crude oil prices currently used for forecasting purposes by the IEA. Figure III-1 illustrates these two projections. One, a “constant price case”, projects oil prices at $20.25 per barrel in 1990 dollars. The other projection, a “rising price case”, foresees oil prices rising to $34.79 by the year 2000.

The risk to investors is not necessarily the same in all segments of an integrated project from the wellhead to the ultimate consumer. Consequently, a different risk premium (hurdle rate) might be required from different segments. In this report, we recognized that companies regard investments upstream in gasfield development as riskier than others downstream in shipping for example. We therefore selected a real annual capital charge[3] of 19 percent as the most appropriate for estimating the cost of service of various gas developments. This would be equivalent to a nominal hurdle rate of

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[3] Capital charge — percentage of initial capital outlay (in real terms) that must be received annually as revenue in order to recover the capital and provide a minimum return on investment.

17 to 20 percent, assuming a 5 percent annual rate of inflation, 3 to 5 year construction period, and 20-year recovery. Our analysis also included an annual operating charge to cover operating costs. These rates and the conditions they bracket are shown in Table III-1.

Figure III-1

WORLD OIL PRICE PROJECTIONS
IEA Crude Oil Import Price Cif

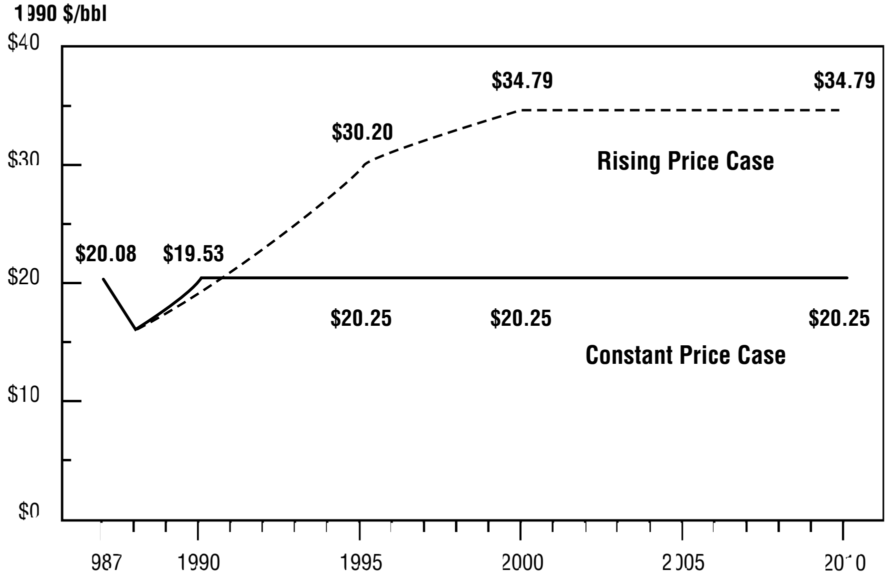


Table III-1

GENERALIZED FINANCIAL PARAMETERS FOR INTERNATIONAL GAS PROJECTS

	Lower Risk		Higher Risk	
Nominal Hurdle Rate	15%	17%	17%	20%
Construction Period	5 years	3 years	5 years	3 years
Recovery Period	20 years	20 years	20 years	20 years
Annual Inflation Rate	5%	5%	5%	5%
Real Annual Capital Charge	15.7%	15.2%	19.0%	19.0%
Annual Operating Charge	3.5%	4.0%	4.0%	4.0%
Real Annual Capital and Operating Charge	19.2%	19.2%	23.0%	23.0%

DEVELOPMENT OF NATURAL GAS COSTS

Many factors affect gas project economics. The cost of developing reliable, long-term feedstock supplies, such as those required for methanol and LNG plants, is frequently higher than is commonly perceived. Reinjected or flared gas produced in association with oil is often unreliable as feedstock and may incur high gathering and compression charges. But good quality non-associated gas reserves are often found in remote locations. There construction may take place in “hostile” conditions with significant exposure to physical, construction and political risk. For new projects, infrastructure costs may be high and sensitive to scale economies. As a result, the combination of a long construction lead-time and high risk premium on investment funds could produce a heavy financial burden on a project.

In view of these factors, gas development may be driven more by the ability to “piggyback” on an existing project or to use by-product credits from gas liquids, for example, than by the availability of reserves. In extreme cases, such as Indonesia’s Natuna field, gas development may be impeded by the penalty cost of removing unwanted constituents, such as carbon dioxide, from the gas stream.

BASIS FOR NATURAL GAS COST FORECASTS

From Jensen Associates' analysis of potential gas supplies, there are several locations in which gas could be produced at a cost of service below $0.50/MMBtu in 1990. They include Sumatra, and Kalimantan, Indonesia; Tierra del Fuego, Chile; non-associated gas in Nigeria, and Qatar and Abu Dhabi in the Middle East. However, the gas would not be available to a new methanol plant on this basis.

In Indonesia, the government and private project participants would be unlikely to threaten the profitability of existing LNG exports by undercutting the gas price into the plant. Elsewhere, host governments would also consider the implicit netback value of their gas from major markets in determining its resource value and their take through taxes or royalties.

Nevertheless, allowing for the market value of gas and the host country's take, the locations above and several others such as Australia and Bangladesh in the Far East; Venezuela and Argentina in Latin America; Algeria and Iran could supply gas to a methanol fuel plant at a price of less than $1.00/MMBtu in 1990. Over time this price could rise, depending on assumptions about alternate gas market values.

The prices estimated for 1990 are shown in Table V-1 and illustrated for various locations in Figures V-1 and V-2.

Figure V-1

ESTIMATED 1990 GAS COSTS AND PRICES

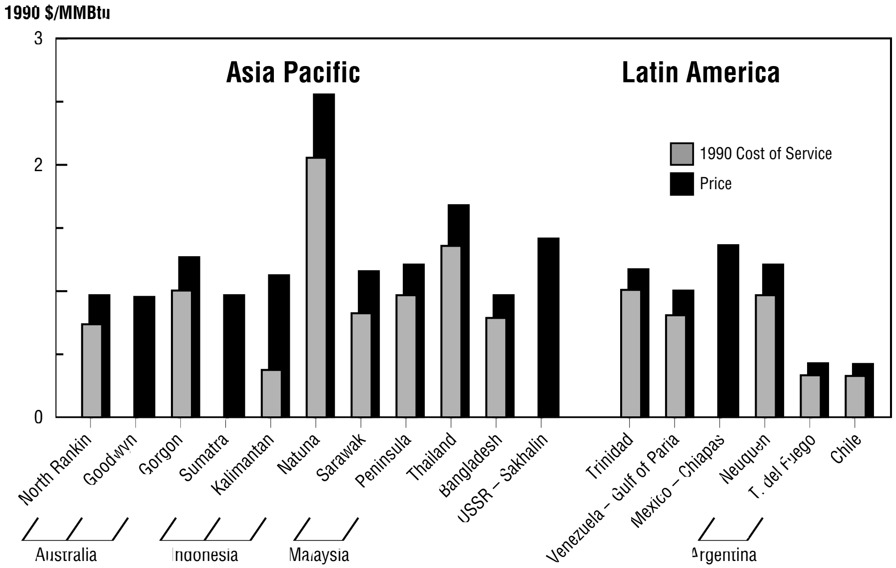


Figure V-2

ESTIMATED 1990 GAS COSTS AND PRICES

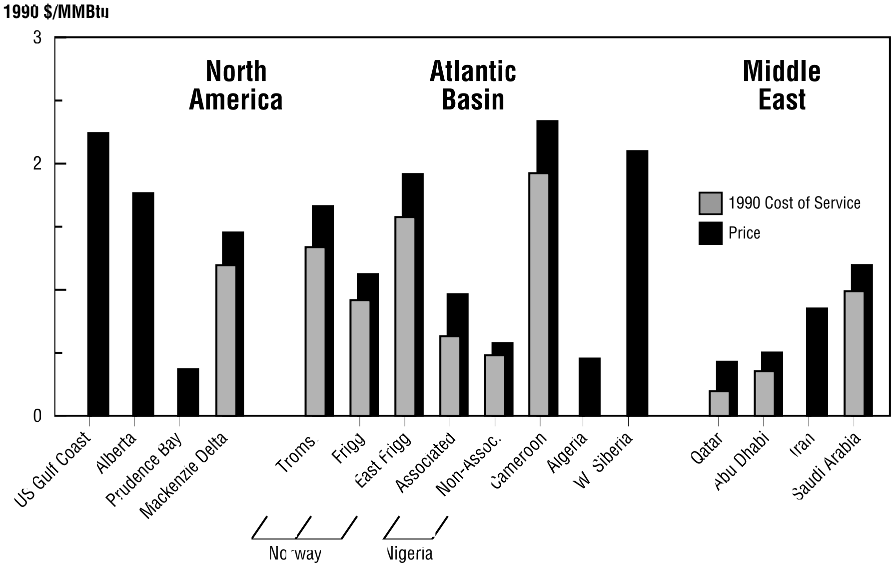


Table V-1

ESTIMATED 1990 GAS COSTS AND PRICES – 1990 $

		Unit(a) Investment $/MMBtu/year	Cost of (b) Service After Credits $/MMBtu	Price $/MMBtu
ASIA PACIFIC				
Australia	– North Rankin A	4.32	0.72	0.91
	– Goodwyn	3.60	–0.78	0.91
	– Gorgon/Tryal Rocks	4.77	0.99	1.23
Indonesia	– Sumatra	3.00	–0.35	0.93
	– Kalimantan	1.96	0.35	1.09
	– Natuna	8.94	2.06	2.50
Malaysia	– Sarawak	3.56	0.82	1.12
	– Peninsula Offshore	4.69	0.95	1.18
Thailand	– Offshore	5.90	1.36	1.65
Bangladesh		3.41	0.78	0.95
U.S.S.R.	– Sakhalin	NA (c)	NA	1.38
LATIN AMERICA				
Trinidad		4.38	1.01	1.15
Venezuela	– Gulf of Paria	3.48	0.80	0.98
Mexico	– Chiapas/Tabasco	NA	NA	1.35
Argentina	– Neuquen	NA	NA	1.18
	– Tierra del Fuego	NA	0.34	0.42
Chile	– Tierra del Fuego	NA	0.34	0.42
NORTH AMERICA				
U.S. Gulf Coast		NA	NA	2.24
Alberta		NA	NA	1.76
Prudhoe Bay		NA	NA	0.36
Mackenzie Delta		5.19	1.19	1.45
ATLANTIC BASIN				
Norway	– Tromsoflaket	6.53	1.33	1.66
	– Frigg	3.96	0.91	1.11
	– East Frigg	6.87	1.58	1.92
Nigeria	– Associated	6.60	0.62	0.95
	– Non-Associated	2.07	0.48	0.58
Cameroon		8.44	1.94	2.36
Algeria		NA	NA	0.46
U.S.S.R. – W. Siberia (in Europe)		NA	NA	2.12
MIDDLE EAST				
Qatar	– North Field	4.73	0.21	0.44
Abu Dhabi		2.84	0.36	0.51
Iran		NA	NA	0.87
Saudi Arabia		NA	1.00	1.22

(a) Data assume 1,100 Btu per cubic foot of gas.
(b) Excluding tax.
(c) Not applicable.

Table V-2

PROJECTED GAS PRICES – 1990 $

		Constant Oil Price Case[a]			Rising Oil Price Case[a]		
		1990 $/MMBtu	2000 $/MMBtu	2010 $/MMbtu	1990 $/MMBtu	2000 $/MMBtu	2010 $/MMBtu
ASIA PACIFIC							
Australia	– North Rankin A	0.91	0.91	0.91	0.80	2.03	2.03
	– Goodwyn	0.91	0.91	0.91	0.80	2.03	2.03
	– Gorgon/Tryal Rocks	1.23	1.23	1.23	1.23	2.17	2.17
Indonesia	– Sumatra	0.93	0.93	0.93	0.82	1.98	1.98
	– Kalimantan	1.09	1.09	1.09	0.98	2.14	2.14
	– Natuna	2.50	2.50	2.50	2.50	2.92	2.92
Malaysia	– Sarawak	1.12	1.12	1.12	1.01	2.18	2.18
	– Peninsula Offshore	1.18	1.18	1.18	1.19	2.22	2.22
Thailand	– Offshore	1.65	1.65	1.65	1.65	2.37	2.37
Bangladesh		0.95	0.95	0.95	0.95	1.96	1.96
U.S.S.R.	– Sakhalin	1.38	1.38	1.38	1.27	2.45	2.45
LATIN AMERICA							
Trinidad		1.15	1.15	1.15	1.15	1.68	1.93
Venezuela	– Gulf of Paria	0.98	0.98	1.23	0.98	1.60	1.85
Mexico	– Chiapas/Tabasco	1.35	2.02	2.68	1.25	3.47	4.03
Argentina	– Neuquen	1.18	1.18	1.18	1.18	1.31	1.56
	– Tierra del Fuego	0.42	0.42	0.42	0.42	1.16	1.16
Chile	– Tierra del Fuego	0.42	0.42	0.42	0.42	1.16	1.16
NORTH AMERICA							
U.S. Gulf Coast		2.24	2.93	3.61	2.12	4.43	5.00
Alberta		1.76	2.44	3.11	1.66	3.91	4.47
Prudhoe Bay		0.36	0.36	0.36	0.36	0.76	1.28
Mackenzie Delta		1.45	1.45	1.57	1.45	2.33	2.86
ATLANTIC BASIN							
Norway	– Tromsoflaket	1.66	1.66	1.66	1.67	1.70	1.95
	– Frigg	1.11	1.11	1.15	1.11	1.51	1.76
	– East Frigg	1.92	1.92	1.92	1.92	1.92	2.17
Nigeria	– Associated	0.95	0.95	0.95	0.98	1.27	1.52
	– Non-Associated	0.58	0.58	0.72	0.58	1.07	1.32
Cameroon		2.36	2.36	2.36	2.36	2.36	2.36
Algeria		0.46	0.51	0.81	0.46	1.17	1.41
U.S.S.R.	– W. Siberia (in Europe)	2.12	2.12	2.12	2.04	3.75	3.75
MIDDLE EAST							
Qatar	– North Field	0.44	0.44	0.44	0.48	1.51	1.51
Abu Dhabi		0.51	0.51	0.51	0.52	1.53	1.53
Iran		0.87	0.87	0.87	0.87	1.71	1.71
Saudi Arabia		1.22	1.22	1.22	1.22	1.88	1.88

[a] Data assume 1,100 Btu per cubic foot of gas.

NATURAL GAS TRANSPORTATION

Several factors influence the optimum economic form in which natural gas can be delivered to market. They include the size of the natural gas resource, its location in relation to potential markets, the land and sea routes available, and the overall distance.

Among the several transportation modes possible, three are compared here. They are:

- movements of gas as LNG;
- large diameter pipeline movements; and
- shipments of natural gas as methanol fuel.

For purposes of comparison, Jensen Associates developed a set of typical financial and operating factors that generally reflect conditions for movements of gas as LNG, large diameter pipeline movements, and shipments of gas as methanol. Because the economics of different transport modes are sensitive to scale, costs were estimated for the size of project which best suits the type of movement considered. Similarly, the costs of conversion to a liquid were included in the case of LNG and methanol. However, downstream costs to regasify the LNG, distribute the pipeline gas, and deliver the methanol fuel were excluded.

On this basis, the delivered cost of fuel required to yield a $1.00/MMBtu gas netback value at the plant or pipe inlet was calculated for each fuel over various distances. The calculations show that for distances up to about 3,000 miles, a large diameter gas pipeline (on land with limited water crossings) is cheaper than both LNG and methanol. Beyond about 3,000 miles, pipeline gas is more expensive to deliver than LNG, and by 7,000 miles it becomes more expensive than methanol also.

Table VI-1 shows generalized capital and operating parameters for a world-scale LNG project. Generalized capital and operating parameters for a large diameter natural gas pipeline are shown in Table VI-2.

Generalized capital and operating parameters for a fuel methanol plant are shown in Table VI-3.

In Figure VI-1, the results for each transportation project are illustrated for distances from 1,000 to 10,000 miles. As the figure demonstrates, the most economic way in which natural gas can be moved to market changes as a function of distance.

From a policy perspective, if the purpose is to identify the most economic way of delivering natural gas to market, the pipeline and LNG options are clearly favored. However, this comparison ignores the “form” value of each fuel. Since methanol can be substituted for gasoline and diesel fuel more readily than the other two fuels, it may be appropriate in some circumstances to take the form value of each fuel into consideration.

Figure VI-1

DELIVERED FUEL VALUE REQUIRED TO YIELD $1.00/MMBtu Netback Gas Value

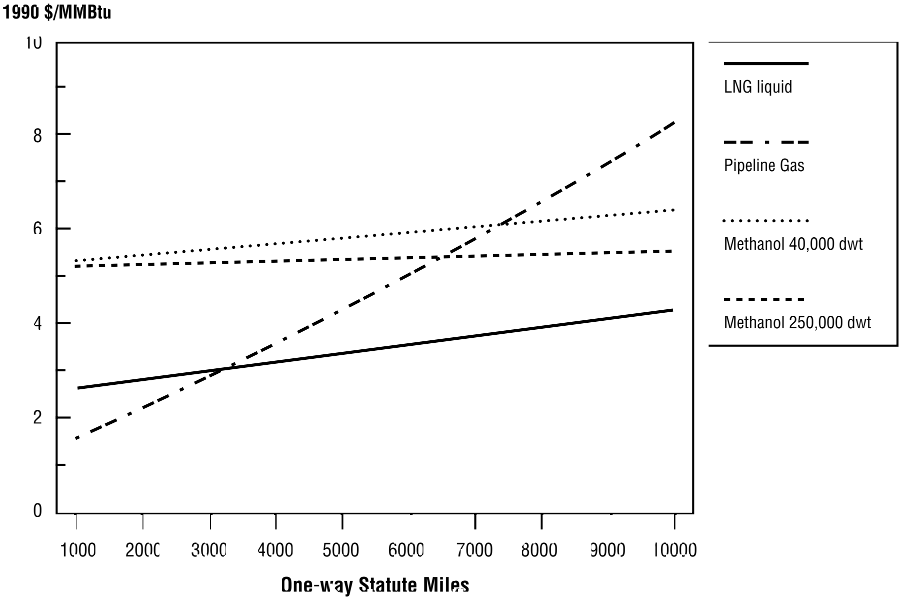


Table VI-1

GENERALIZED CAPITAL AND OPERATING PARAMETERS FOR AN LNG PROJECT

Liquefaction

- 3 x 2 million tonne/year liquefaction trains i.e. 6 MMt/year LNG output
- Plant fuel and loss equal to 9 percent of input volume
- Plant cost $2,100 million (1990 dollars)

Shipping

- 125,000 cu. m. vessels; number varies with distance
- Average boil-off rate 0.15 percent/day round trip of volume carried
- Boil-off gas consumed as ship fuel
- Other costs taken at 3.5 percent of vessel cost
- 340 operating days/year; speed 18.5 knots; 24 hours port time each end
- Cost of vessel $210 million

Conversion Factors

- Assuming 1,100 Btu/cubic foot of gas:
  - 1 tonne of LNG equals
    — 2.21 cu.m. liquid
    — 1,324 cu.m. gas
    — 46.76 Mcf gas
    — 51.43 MMBtu
  - 1 MMt/year of LNG equals 128 MMcfd of gas
    1,324 million cubic metres/year of gas

Table VI-2

GENERALIZED CAPITAL AND OPERATING PARAMETERS FOR A LARGE DIAMETER NATURAL GAS PIPELINE

Pipe

- 42 inch nominal pipe size
- Maximum throughput 1,000 MMcfd
- Cost of pipe $1 million/mile (1990 dollars)

Compression

- Length of pipe 1,000 miles
- Number of compressor stations 11
- Total installed brake horsepower 118,500 hp
- Total operating brake horsepower 115,055 hp
- Fuel consumption at peak day operation 20 MMcf i.e. 2% of throughput
- Cost of compression $1,110/hp

Land

- Cost of land, right of way, transit fees equal to 2% of capital cost per 1,000 miles

Non-Gas Operating Cost

- Equal to 1% of capital cost per 1,000 miles

Table VI-3

GENERALIZED CAPITAL AND OPERATING PARAMETERS FOR A FUEL METHANOL PLANT

Methanol Production

- 4 x 2,500 tonne/day fuel methanol trains i.e. 10,000 tonne/day capacity
- Annual operating factor 95%
- Annual methanol production 1,151 million U.S. gallons
- Plant cost $1,260 million (1990 dollars)
- Non-gas operating cost 7.8 cents/gallon
- Annual natural gas consumption 109.6 Bcf

Shipping

- 40,000 dwt and 250,000 dwt vessels; number varies with distance
- 340 operating days/year; speed 12 knots; 24 hours port time each end
- Volume of methanol carried per trip: 40,000 dwt – 13.6 million U.S. gal.
  250,000 dwt – 85.0 million U.S. gal.
- Non-fuel operating costs: 40,000 dwt — $5,350/day
  250,000 dwt — $7,025/day
- Fuel cost: 40,000 dwt at sea — $2,670/day
  in port — $ 875/day
  250,000 dwt at sea — $3,570/day
  in port — $ 875/day
- Cost of vessel: 40,000 dwt — $25 million
  250,000 dwt — $70 million

Conversion Factors

- 1 barrel of methanol contains 2.9 MMBtu (gross heat value)
- 1 U.S. gallon of methanol contains 0.0693 MMBtu (gross heat value)

Table VI-4

DELIVERED FUEL VALUE REQUIRED TO YIELD $1.00/MMBtu GAS NETBACK VALUE

One-Way Statute Miles	Liquid LNG $/MMBtu	Pipeline Gas $/MMBtu	Methanol 40,000 dwt $/MMBtu	Methanol 250,000 dwt $/MMBtu
1,000	2.67	1.61	5.30	5.20
2,000	2.84	2.25	5.43	5.24
3,000	3.02	2.91	5.55	5.29
4,000	3.20	3.60	5.68	5.33
5,000	3.39	4.31	5.80	5.37
6,000	3.57	5.05	5.93	5.42
7,000	3.76	5.82	6.05	5.46
8,000	3.95	6.62	6.18	5.50
9,000	4.14	7.46	6.30	5.55
10,000	4.34	8.31	6.43	5.59

Part III

Summary of the Economic Comparisons of LNG, Methanol and Synthetic Distillate Study

August 1991

Study performed by:
Jensen Associates, Inc.
Boston, Massachusetts

SUMMARY OF THE ECONOMIC COMPARISONS OF LNG, METHANOL AND SYNTHETIC DISTILLATE STUDY

INTRODUCTION

In Phase I of its study for the International Energy Agency's Implementing Agreement on Alternative Motor Fuels, Jensen Associates, Inc. (JAI) identified those gas reserves worldwide which were sufficient for supplying a 10,000 tonne/day methanol plant operating for 20 years (at least 2.5 trillion cubic feet of natural gas), which were uncommitted to other projects, and whose potential production rates were likely to be sufficiently reliable to support continuous operation of such a large worldscale plant. Where qualifying reserves were found, JAI estimated the price at which gas might be produced and processed ready for an export facility. These plant gate prices considered not only production costs, but host government take, and, where applicable existing export prices or opportunity costs. JAI further provided some *pro forma* estimates of capital and operating costs for LNG and methanol plants, for pipelines, and for the cost of ocean transport, in order to suggest the general parameters which might govern a country's or company's decision as to which option — pipeline, LNG or methanol — to use in exporting its natural gas. These general estimates were used to develop a decision matrix regarding the optimal economic form of gas export as a function of distance.

OBJECTIVES OF THE STUDY

To develop a methodology for and to calculate the cost of delivering gas as LNG, methanol and also as middle distillates (using a process like the Shell Middle Distillate Conversion) from each viable surplus source of natural gas, to three representative markets — Tokyo, Rotterdam and the U.S. Gulf Coast.

SITE SELECTION AND METHODOLOGY

Seventeen countries (in some cases including multiple large gas fields) were selected for study from those identified in Phase I as having sufficient uncommitted gas reserves to supply a worldscale export LNG, methanol or middle distillate plant over a 20-year life (Table I-2). For each gas source, a plant site was designated based on proximity to the gas field or port. Fob prices for LNG, methanol and middle distillates were developed using capital and operating costs appropriate to the designated plant sites (Tables II-3, II-4, II-5) .

For example, a Category II site, such as Trinidad, with some degree of infrastructure and development, but relatively high construction costs, the plant capital and operating costs (using a 19.2% capital recovery factor) were estimated to be $1.20/MMBtu for LNG, $3.68/MMBtu for methanol, and $3.10/MMBtu for middle distillates. The capital and operating costs were adjusted for other sites, depending upon the relative degree of development, existing infrastructure and construction costs. Plant capital and operating costs were highest in harsh, remote and undeveloped sites, such as the Tromsoflaket area offshore Norway, Mackenzie Delta in Canada and Natuna Island offshore Indonesia. The lowest capital and operating costs were assumed to prevail onshore in highly industrialized countries with large existing energy infrastructures, such as the U.S. Gulf Coast and Alberta, Canada (Table II-2).

Fully delivered costs (including regasification costs in the case of LNG) were arrived at by adding the fob and shipment costs in the largest practical dedicated tankers traveling the shortest nautical route. A full range of these cif costs were calculated, including all product form and market combinations which were not *a priori* illogical (for example, shipping LNG from Tromsoflaket, Norway to the Tokyo market). Using the cif costs it was possible to rank in order the preferred sources of a particular product for a particular market. For example, the cheapest source of methanol delivered to the Tokyo market would be Qatar, while Algeria was the cheapest source for both Rotterdam and the U.S. Gulf Coast. Combining the potential supply sources for each market, from the cheapest to most expensive, and estimating the number of worldscale plants in each location, JAI drew supply curves for each product in each market.

The cif estimates based on a cost build-up answer the question of which sources a particular market might prefer. They do not, however, address the question of the most economical product/market combination for a particular gas source. The products considered, LNG, methanol, and middle distillates, are used for different applications and their market value (including any form premium) would be related to the cost of alternative fuels used for those different applications. For example, the largest movements of LNG today are for power generation in Japan, where the LNG competes with low-sulfur fuel oil for market share. By contrast, methanol historically has been used as a chemical feedstock, and now is being considered as an alternative fuel in the automotive transportation market, where it would compete with, or be a blending component of, gasoline. Middle distillate products have a wide range of uses, including transportation and residential/commercial heating applications. Although the price of delivered natural gas was expressed in common units ($/MMBtu), this comparison of the cost-based cif prices of one gas-based product with another in a given market ignores the form premiums which apply to each product.

In order to derive estimates of delivered product prices which would allow cross-product comparisons, JAI has developed a second set of delivered prices which eliminate from each product a cost equivalent to the costs of conversion (or liquefaction) at a standard Site Category II location. The logic of this approach is based on the following example. Since natural gas is the raw material for methanol, the value of the methanol should be higher than that of its feedstock by the cost of conversion in a market where both gas and methanol prices are set by the marketplace. By taking out the standard cost of conversion, the remaining elements of delivered cost (as expressed in a common unit such as $/MMBtu) reflect the factors that differentiate sites and processes, such as thermal efficiencies, relative transport costs and relative site premia. In effect, it is assumed that the standard plant capital and operating costs are a proxy for the form premia prevailing in the marketplace.

Using the delivered costs less plant capital and operating costs, it is possible to ignore the different applications of the products and determine the most economical gas-based product/market combinations for each gas source. These ex-capital and operating delivered costs embody a complex set of trade-offs involving country gas prices (from Phase I), site premia, conversion losses, per mile transportation costs, and distance from market (Tables II-6, II-7).

In general the results of the cross-product comparisons by gas source in any given market indicate that where country gas prices are low, there is room to trade-off the higher conversion losses associated with either methanol or middle distillate gas conversion (combined with lower per-mile transport costs) in order to supply more distant markets. Very high cost gas sources, especially when combined with high site penalties (such as the Natuna field offshore Indonesia), quickly become economically unattractive when high conversion losses or long distance transport costs are added. Figures II-5, II-6 and II-7 illustrate the subtleties operating in the cross product comparisons for each market. As the three figures suggest, the various siting, feedstock costing and transport distances interact in complex ways. For example, methanol is at a disadvantage in regions with high cost gas, such as Natuna or Tromsoflaket, while it has an advantage over LNG for long distances, such as Tierra del Fuego/Rotterdam relative to Algeria/Rotterdam.

Table I-2

MATRIX OF GAS SOURCE, FORM, AND DESTINATION MARKETS

X = To Be Explored, O = Eliminated From Study

GAS SOURCE Country/Field or Port/Fuel Form	DESTINATION MARKET			Reason for Elimination (O)
	U.S.[1]	Rotterdam	Tokyo Bay	
Abu Dhabi				
LNG	O	X	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Algeria				
Arzew				
Skikda				
LNG	X	X	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Argentina				
Neuquen (Bahia Blanca)				
LNG	X	X	O	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Tierra del Fuego (Argentina/Chile)				
LNG	X	X	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Australia				
North Rankin (A)				
LNG	O	O	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	

---

[1] For U.S., LNG deliveries are to Cove Point; methanol and middle distillate deliveries are to Houston.

Table I-2 (continued)

MATRIX OF GAS SOURCE, FORM, AND DESTINATION MARKETS

X = To Be Explored, O = Eliminated From Study

GAS SOURCE Country/Field or Port/Fuel Form	**DESTINATION MARKET**			**Reason for Elimination (O)**
	U.S.	**Rotterdam**	**Tokyo Bay**	
Canada				
Alberta/British Columbia				
LNG[2]	O	O	X	Pipeline movements to Canada or U.S. most likely, though exports may be feasible. LNG to Tokyo has been discussed.
Methanol	X	O	X	
Middle Distillates	X	O	X	
Mackenzie Delta				
Methanol	X	O	X	Gas transformed to liquid form in Delta and moved to Edmonton.
Middle Distillates	X	O	X	
Indonesia				
Sumatra (Belawan)				
Kalimantan (Balikpapan)				
Natuna Island				
LNG	O[3]	O	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Iran				
LNG	O	X	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Iraq				
LNG	O	X	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	

---

[2] Gas delivered to Canadian and U.S. markets by pipeline and, as such, price will be governed by prevailing price structure.

[3] Indonesia has made a single LNG delivery to the U.S. However, from an economic point of view, such a movement is illogical and cannot be expected to persist.

Table I-2 (continued)

MATRIX OF GAS SOURCE, FORM, AND DESTINATION MARKETS

X = To Be Explored, 0 = Eliminated From Study

GAS SOURCE Country/Field or Port/Fuel Form	DESTINATION MARKET U.S.	Rotterdam	Tokyo Bay	Reason for Elimination (0)
Malaysia				
Sarawak				
Peninsula				
LNG	0	0	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Mexico				
Chiapas/Tabasco				
Pipeline	X	0	0	Proximity to U.S. market rules
LNG	0	0	0	out LNG to any market
Methanol	X	X	X	
Middle Distillates	X	X	X	
Netherlands				
Pipeline	0	X	0	Additional Dutch gas supplies
LNG	0	0	0	will stay in Europe
Methanol	0	0	0	
Middle Distillates	0	0	0	
Nigeria				
LNG	X	X	0	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Norway				
Tromsoflaket				
LNG	X	X	0	Proximity to European and U.S.
Methanol	X	X	0	markets precludes shipment to
Middle Distillates	X	X	0	Tokyo from Norwegian
Frigg and East Frigg				sources.
Pipeline/LNG	X	X	0	
Methanol	X	X	0	
Middle Distillates	X	X	0	
Qatar/North Field				
LNG	0	X	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	

Table I-2 (completed)

MATRIX OF GAS SOURCE, FORM, AND DESTINATION MARKETS

X = To Be Explored, O = Eliminated From Study

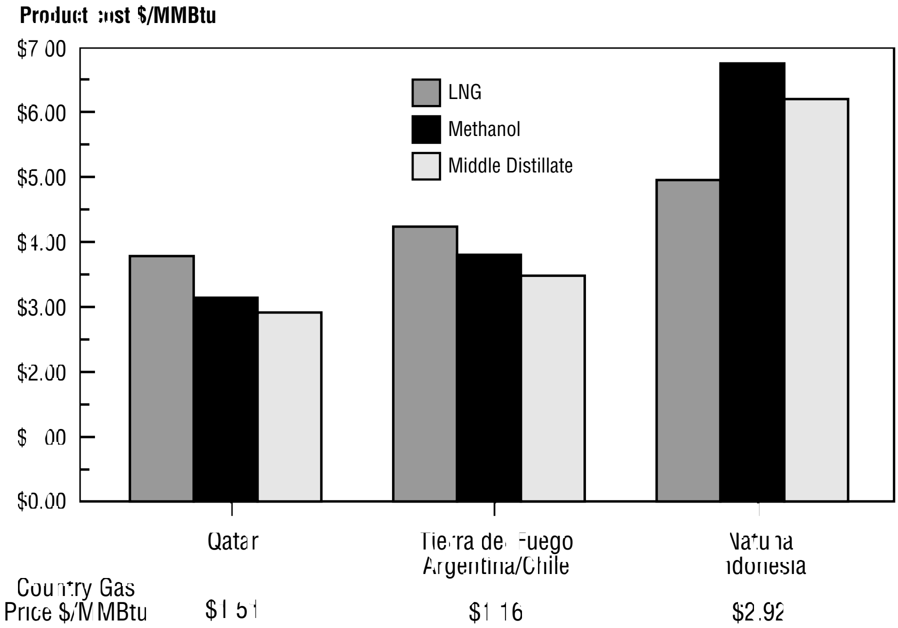
GAS SOURCE Country/Field or Port/Fuel Form	DESTINATION MARKET			Reason for Elimination (O)
	U.S.	Rotterdam	Tokyo Bay	
Saudi Arabia				
LNG		O	X	X
Methanol	X	X	X	
Middle Distillates	X	X	X	
Trinidad				
LNG		X	X	O
Methanol	X	X	X	
Middle Distillates	X	X	X	
U.S.				
Gulf Coast				
Pipeline	O	O	O	U.S. Lower 48 gas assumed to remain within U.S.
LNG	O	O	O	
Methanol	X	O	O	
Middle Distillates	X	O	O	
Prudhoe Bay				
LNG[4]	O	O	O	
Methanol	X	O	X	
Middle Distillates	X	O	X	
U.S.S.R.				
Sakhalin				
Yakut				
LNG	O	O	X	
Methanol	X	X	X	
Middle Distillates	X	X	X	
Venezuela				
Gulf of Paria				
LNG	X	X	O	Proximity to U.S. and European markets precludes shipment to Tokyo
Methanol	X	X	X	
Middle Distillates	X	X	X	

---

[4] While a large-scale LNG project directed towards the Far East has been under study, it is a unique project suggesting that comparison with other projects is not meaningful.

Figure II-5

COMPARISON OF DELIVERED COSTS* TO TOKYO MARKET
Rising Oil Price Case for 2010



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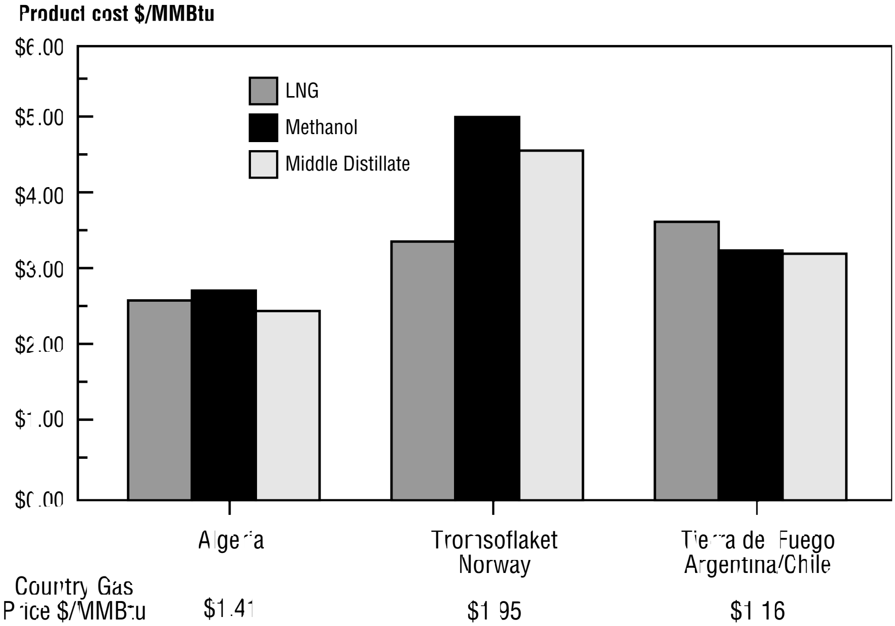
*Excludes plant, operating and capital costs. All costs in 1990 $.

Figure II-6

COMPARISON OF DELIVERED COSTS* TO ROTTERDAM MARKET
Rising Oil Price Case for 2010



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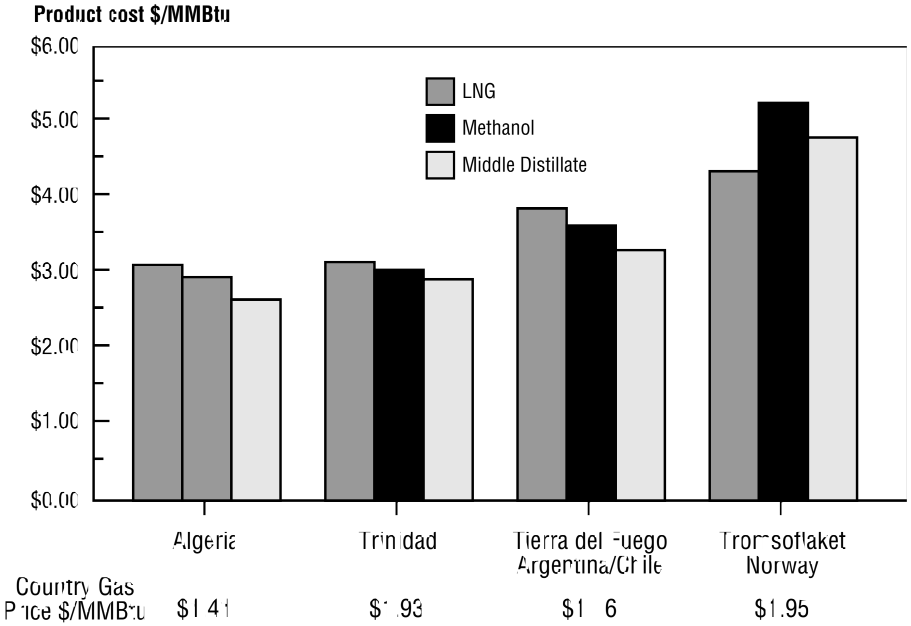
*Excludes plant, operating and capital costs. All costs in 1990 $.

Figure II-7

COMPARISON OF DELIVERED COSTS* TO U.S. GULF MARKET
Rising Oil Price Case for 2010



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*Excludes plant, operating and capital costs. All costs in 1990 $.

Table II-2

SPECIFIC SITE LOCATION CATEGORIZATION BY GAS SOURCE

LOCATION	SITE CATEGORY
Abu Dhabi	II/III
Algeria	II/III
Argentina-Neuquen	III
Argentina/Chile – T. del Fuego	III
Australia – N. Rankin	IV
Canada	
Alberta	I
Mackenzie Delta	IV
Indonesia	
Sumatra	III
Kalimantan	III
Natuna	IV
Iran	II/III
Iraq	II/III
Malaysia	
Sarawak	III
Peninsula	IV
Mexico-Chiapas/Tabasco	II/III
Netherlands	I
Nigeria	III
Norway	
Tromsoflaket	IV
Frigg & E. Frigg	III
Qatar	II/III
Saudi Arabia	II/III
Trinidad	II
U.S.A. – Gulf Coast	I
U.S.S.R.	
Sakhalin	IV
Yakut	IV
Venezuela – Gulf of Paria	III

Table II-3

GENERALIZED CAPITAL AND OPERATING PARAMETERS FOR A LNG PROJECT

Liquefaction

- 3 x 2 million tonne/year liquefaction trains i.e., 6 MMt/year LNG output
- Plant fuel and loss equal to 9 percent of input volume
- Plant cost $2,100 million (1990 dollars) at a Category II site
- Capital charge at 15.7% and operating charge of 3.5% of capital cost
- Annual natural gas consumption – 312 Bcf
- Thermal efficiency at 90%

Shipping

- 125,000 cu. m. vessels; number varies with distance
- Average boil-off rate 0.15 percent/day round trip of volume carried
- Boil-off gas consumed as ship fuel
- 2 days in port per voyage
- Other costs taken at 3.5 percent of vessel cost
- 340 operating days/year; speed 18.5 knots; 24 hours port time each end
- Cost of vessel $210 million

Regasification

- Regasification in destination market at a cost of $0.32/MMBtu (1990 dollars)
- Plant fuel and loss equal to 1%

Conversion Factors

- Assuming 1,100 Btu/cubic foot of gas:
    - 1 tonne of LNG equals
        — 2.21 cu.m. liquid
        — 1,324 cu.m. gas
        — 46.76 Mcf gas
        — 51.43 MMBtu
    - 1 MMt/year of LNG equals 128 MMcfd of gas
        1,324 million cubic metres/year of gas

Table II-4

GENERALIZED CAPITAL AND OPERATING PARAMETERS FOR A FUEL METHANOL PLANT

Methanol Production

- 4 x 2,500 tonne/day fuel methanol trains i.e., 10,000 tonne/day or 3.65 MM tonnes/year output capacity
- Annual operating factor 95%
- Annual methanol production 1,151 million U.S. gallons (3.5 million tonnes per year)
- Plant cost $1,260 million (1990 dollars) at a Category II site
- Annual natural gas consumption 109.6 Bcf
- Capital charge of 15.7% and operating charge at 3.5% of capital cost
- Thermal efficiency at 66.2%

Shipping

- 250,000 dwt vessels (except 125,000 dwt on routes through canals); number varies with distance
- 340 operating days/year; speed 12 knots; 24 hours port time each end
- Volume of methanol carried per trip: 250,000 dwt — 85.0 mill U.S. gallons
- Non-fuel operating costs: 250,000 dwt — $7,025/day
- Fuel cost: 250,000 dwt at sea — $3,570/day
  in port — $875/day
- Cost of vessel: 250,000 dwt — $70 million

Conversion Factors

- 1 barrel of methanol contains 2.9 MMBtu (gross heat value)
- 1 U.S. gallon of methanol contains 0.0693 MMBtu (gross heat value)
- 1 U.S. gallon = 3.78 liters

Table II-5

GENERALIZED CAPITAL AND OPERATING PARAMETERS FOR A PLANT CONVERTING GAS TO MIDDLE DISTILLATES

Middle Distillate Production

- Plant output at 48,000 barrels per calendar day[1] or 2.27 million tonnes/year
- Feedstock requirement at 428.3 MMcfd (62.2 million tonnes per year) (8.92 MMBtu/barrel)
- Thermal efficiency at 65%
- Annual combined capital and operating charge of 19.2% of capital cost
- Annual natural gas consumption of 156.3 Bcf
- Plant cost $1,600 million (1990 dollars) at Site Category II

Shipping

- 250,000 dwt dedicated tankers (except 125,000 dwt through canals)
- 340 operating days/year; speed of 12 knots; 24 hours of port time each end

Product Yield

- Percentage Output

	Possible Range of Yield	Assumed Output
Naphtha	15-25%	20%
Kerosine	25-50%	40%
Distillate/gas oil	25-60%	40%

- Average Btu content per barrel of 5.65 MMBtus
- Average barrels per metric tonne of 7.71

---

[1] Capacity stated in barrels per calendar day (BPCD) is maximum output averaged over a 365-day year.

Table II-6

RANKING OF THE TOP TEN SUPPLIERS TO EACH MARKET BY PRODUCT
Rising Oil Price Case for 2010

	LNG	METHANOL	DISTILLATE
Tokyo			
1	Indonesia, Sumatra	Abu Dhabi	Abu Dhabi
2	Malaysia, Sarawak	Qatar	Qatar
3	Indonesia, Kalimantan	Iran	Iran
4	Abu Dhabi	Iraq	Iraq
5	Qatar	Saudi Arabia	Algeria
6	East Siberia, Sakhalin	Trinidad	Saudi Arabia
7	Australia, N.W. Shelf	Algeria	Argentina/Chile, T. del Fuego
8	East Siberia, Yakut	Argentina/Chile, T. del Fuego	Trinidad
9	Iran	Venezuela	Venezuela
10	Malaysia, Peninsula	Nigeria	Nigeria
Rotterdam			
1	Algeria	Algeria	Algeria
2	Norway, Frigg, East Frigg	Trinidad	Trinidad
3	Nigeria	Qatar	Qatar
4	Norway, Tromsoflaket	Abu Dhabi	Abu Dhabi
5	Trinidad	Venezuela	Venezuela
6	Argentina/Chile, T. del Fuego	Argentina/Chile, T. del Fuego	Argentina/Chile, T. del Fuego
7	Venezuela	Iran	Iran
8	Abu Dhabi	Iraq	Iraq
9	Qatar	Nigeria	Nigeria
10	Argentina, Neuquen	Saudi Arabia	Saudi Arabia
U.S.			
1	Algeria	Algeria	Algeria
2	Trinidad	Trinidad	Trinidad
3	Venezuela	Venezuela	Venezuela
4	Norway, Frigg, East Frigg	Qatar	Qatar
5	Nigeria	Abu Dhabi	Argentina/Chile, T. del Fuego
6	Argentina/Chile, T. del Fuego	Argentina/Chile, T. del Fuego	Abu Dhabi
7	Argentina, Neuquen	Iran	Iran
8	Norway, Tromsoflaket	Iraq	Nigeria
9		Nigeria	Iraq
10		Saudi Arabia	Argentina, Neuquen

Table II-7

RANKING OF THE TOP TEN SUPPLIERS TO EACH MARKET BY PRODUCT

Constant Oil Price Case for 2010

	LNG	METHANOL	DISTILLATE
Tokyo			
1	Malaysia, Sarawak	Qatar	Qatar
2	Indonesia, Sumatra	Abu Dhabi	Abu Dhabi
3	Qatar	Iran	Iran
4	Indonesia, Kalimantan	Iraq	Iraq
5	Indonesia, Natuna	Trinidad	Algeria
6	Abu Dhabi	Algeria	Argentina/Chile, T. del Fuego
7	Australia, N.W. Shelf	Argentina/Chile, T. del Fuego	Trinidad
8	East Siberia, Sakhalin	Saudi Arabia	Saudi Arabia
9	East Siberia, Yakul	Indonesia, Sumatra	Indonesia, Sumatra
10	Malaysia, Peninsula	Venezuela	Venezuela
Rotterdam			
1	Algeria	Qatar	Qatar
2	Norway, Frigg	Algeria	Algeria
3	Trinidad	Abu Dhabi	Abu Dhabi
4	Nigeria	Trinidad	Trinidad
5	Qatar	Iran	Iran
6	Abu Dhabi	Iraq	Iraq
7	Argentina/Chile T. del Fuego	Argentina/Chile, T. del Fuego	Argentina/Chile, T. del Fuego
8	Venezuela	Venezuela	Venezuela
9	Norway, Tromsoflaket	Saudi Arabia	Saudi Arabia
10	Iran	Nigeria	Nigeria
U.S.			
1	Trinidad	Trinidad	Algeria
2	Algeria	Algeria	Trinidad
3	Venezuela	Qatar	Qatar
4	Argentina/Chile, T. del Fuego	Abu Dhabi	Abu Dhabi
5	Norway, Frigg	Venezuela	Venezuela
6	Nigeria	Argentina/Chile, T. del Fuego	Argentina/Chile, T. del Fuego
7	Argentina, Neuquen	Iran	Iran
8	Norway, Tromsoflaket	Iraq	Iraq
9		Nigeria	Nigeria
10		Saudi Arabia	Saudi Arabia

THERMAL EFFICIENCIES AND ENVIRONMENTAL IMPACT OF LNG, METHANOL AND MIDDLE DISTILLATES

The three gas conversion processes considered in this report — LNG, methanol and middle distillates — have widely varying thermal efficiencies. The efficiency of converting natural gas to LNG (including transportation and regasification) runs 84-89% for the routes considered, while methanol is assumed to be 66% and middle distillate conversion about 65%.

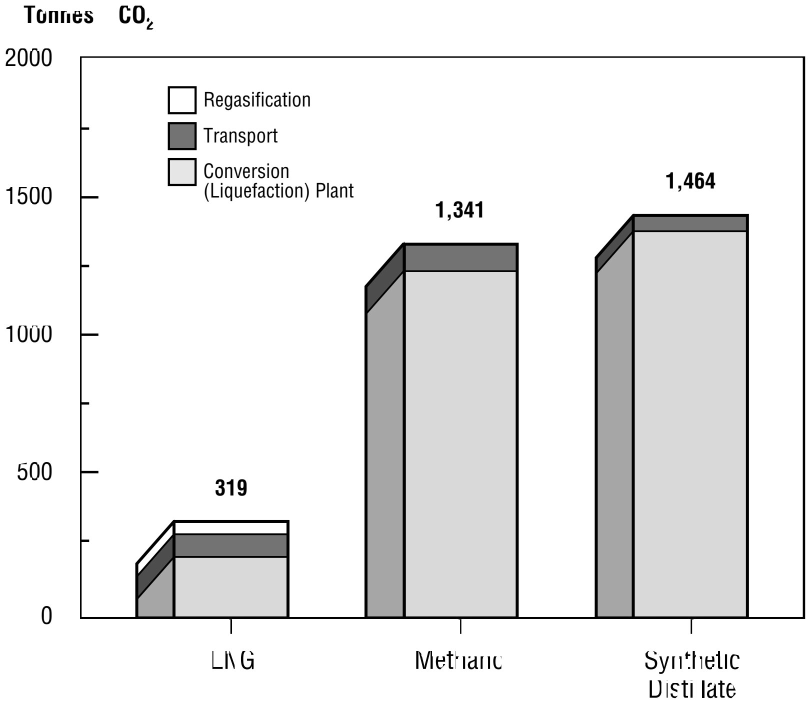
The poorer thermal efficiency of the middle distillate and methanol processes relative to that of LNG implies that they provide a higher carbon dioxide emission level for an equivalent amount of delivered energy than does LNG. Because methanol has a much lower heat content per tonne than either of the two hydrocarbons, methanol's emission level appears much better than that of distillate when the comparison is done per tonne of product delivered.

Table III-1 summarizes the estimated CO_2 emissions from plant operations, transportation and regasification for the three conversion processes. Distillate emissions per tonne of product are roughly twice those of methanol, which in turn are roughly twice those of LNG.

When the emissions are adjusted for heat content, however, using the international energy convention of Millions of Tonnes of Oil Equivalent (MTOE) for the products, the distillate emissions are less than 10% greater than those of methanol. LNG looks even better relative to methanol and distillate when compared on the basis of heating value, since its energy content per tonne is the highest of the three. Figure III-4 illustrates the emissions comparisons of Table III-1 on an energy content basis (thousand tonnes of CO_2 per MTOE).

Figure III-4

CARBON DIOXIDE EMISSIONS PER MTOE* OF PRODUCT DELIVERED



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*MTOE – Million Tonnes of Oil Equivalent

Table III-1

SUMMARY OF FUEL COMBUSTION LOSSES TAKEN AS CO_2
Thousand Tonnes/Year

	LNG[1]	METHANOL	DISTILLATE
Plant Operations			
Plant Output	6,248	3,468	2,417
Fuel and Losses			
Plant Operations	618	884	1,301
Gas Fuel & Boil-off	187	—	—
Bunker Fuel (Oil)[2]	—	53	39
Bunker Fuel (Gas Equivalent)[3]	—	61	45
Regasification	61	—	—
Total Fuel & Loss			
Thousand Tonnes/Year	866	945	1,346
CH_4 Equivalent/Million Tonnes	144	272	557
CO_2 Equivalent/Million Tonnes	397	749	1,532
CO_2 – Thousand Tonnes/MTOE[4]	319	1,341	1,464

[1] Assuming a 4,000 nautical mile round trip
[2] Assuming 3% of cargo on round trip
[3] Assuming bunker fuel has 15% more carbon than methane
[4] MTOE – Million Tonnes of Oil Equivalent

Part IV

Summary of the Comparison of the Production of Methanol and Ethanol from Biomass Study

October 1993

Study performed by:
TDA Research, Inc.
Wheat Ridge, Colorado

SUMMARY OF THE COMPARISON OF THE PRODUCTION OF METHANOL AND ETHANOL FROM BIOMASS STUDY

OBJECTIVE

Over the past two decades extensive research has been carried out on the production of methanol and ethanol from biomass. This interest is a result of concerns over the price and availability of liquid fossil fuels, balance-of-payment problems resulting from expensive oil imports, urban air quality problems created by gasoline and diesel combustion, and recently, concerns over the accumulation of carbon dioxide in the atmosphere and its effect on the global environment. While the production of methanol and ethanol from renewable biomass resources has the potential to alleviate many of these problems, these alcohol fuels must be available in large quantities at a competitive cost if they are to make a significant contribution.

While numerous reports have evaluated various processes for producing either methanol or ethanol, it is still difficult to compare the status of these two technologies. The available studies focus on a single process, and use different technical and economic assumptions, different feedstocks and different plant sizes. The processes evaluated are often at different stages of development, leading one to compare hard numbers with optimistic projections. Unfortunately the lack of a consistent comparison of the various processes makes it difficult to rationally plan national research strategies. Thus, the overall objective of this study is to compare the production of methanol and ethanol on a consistent basis. Specific objectives are to allow the reader to understand: 1) the relative economics of methanol and ethanol processes, 2) the fundamental phenomena which govern the different processes and determine their cost and performance, and 3) what types of process improvements are necessary in order to reduce the cost of producing alcohols from biomass.

METHODOLOGY

This study compares processes which are at similar stages of development, uses performance and cost data derived from existing engineering analysis, and adjusts the feedstock cost, plant size, and the technical and economic parameters to a common basis. The processes are evaluated at four different levels of development, *i.e.*, technology which has been: 1) commercially demonstrated, 2) demonstrated at the pilot scale 3) demonstrated at the laboratory scale, and 4) advanced cases which attempt to predict the potential for improvement.

The parameter used to compare different processes is the cost of production of the neat fuel, expressed on an energy basis as United States $/GJ (lower heating value). This figure of merit allows the comparison of fuels with different energy densities. The feedstock was taken as a typical hardwood (red oak or *Quercus rubra*), delivered to the plant gate at a rate of 1,818 tonne/day, and a cost of $46/dry tonne. The plant was designed as a grass-roots facility, with a cost typical of the midwestern United States, Canada, Western Europe or Japan (approximately 15% higher than United States Gulf Coast capital costs). The cost of production is calculated as:

$$\text{Cost of Production} = \frac{\text{Capital Investment} * \text{CRF} + \text{Annual Operating Expenses}}{\text{Annual Production}}$$

The capital recovery factor (CRF) is a function of the required return on investment, the inflation rate, tax rate, construction time, and plant life. The base case CRF used in this study is 30%, equivalent to an internal rate of return of 15%, with inflation of 3%, and a 20-year plant life. This amounts to a 3.3 year simple payback of the capital investment. Sensitivity analysis were also carried out to determine the effect of plant size, feedstock cost, and the capital recovery factor on the conclusions.

BIOCHEMICAL CONVERSION OF BIOMASS TO ETHANOL

The processes used in the biochemical conversion of biomass to ethanol are dictated by the nature of the feedstock. Lignocellulosic biomass (hardwoods, softwoods, and herbaceous crops such as grasses) is made up of three major components: cellulose, hemicellulose and lignin. The largest fraction of biomass is crystalline cellulose (46% by weight in a typical hardwood). This component consists of long chains of glucose molecules that, because of their crystalline packing, are difficult to hydrolyze (break down into simple sugar units), either with enzymes or even with hot acids. However, once the sugars are produced, they are easy to ferment. The second fraction, hemicellulose (30 wt %), consists of polymers of the five-carbon sugar xylose, as well as other sugars and organic acids. Because this fraction is not crystalline, it is easy to hydrolyze to sugars and other small molecules; however, the xylose cannot be fermented to ethanol by standard yeasts, and the organic acids are not fermentable to ethanol. Lignin, the final major fraction (24 wt%), is not a sugar polymer, but is a phenolic polymer which cannot be fermented to ethanol. Lignin accounts for more of the energy content of the wood than is apparent at first glance, since it has a low oxygen content and therefore a high heat of combustion. On an energy basis, cellulose accounts for 42% of the energy content, hemicellulose 26%, and lignin 32%.

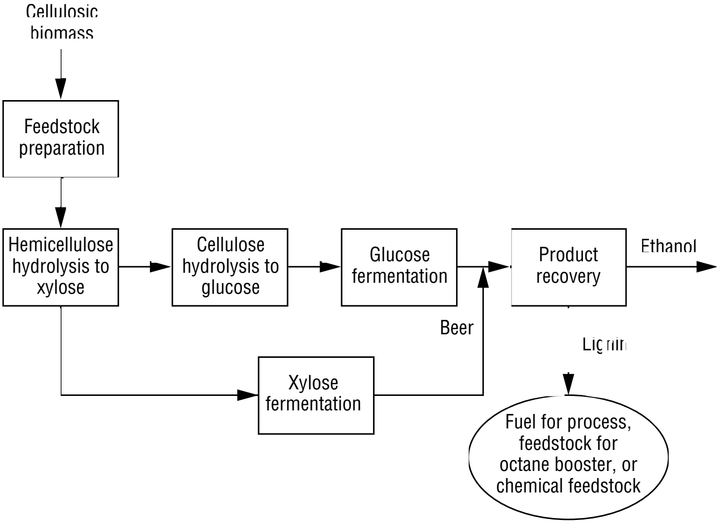
A general schematic of the bioconversion of lignocellulosic biomass to ethanol is shown in . The feedstock is brought to the plant, and the hemicellulose is hydrolyzed, producing xylose (which is fermented in the more advanced processes). In the case of the enzymatic hydrolysis processes, the hemicellulose hydrolysis also opens the biomass structure to enzymatic attack. The cellulose is then hydrolyzed to glucose, either by acids or enzymes, and the resulting glucose fermented to produce ethanol by the reaction.

$$C_6H_{12}O_6 \rightarrow 2\,CO_2 + 2\,C_2H_5OH$$

In the process designs evaluated in this study, the lignin, unfermented sugars, and other organics which are not fermented to ethanol are ultimately dried and burned to produce steam and electricity. As we shall see, the advantages of the bioconversion processes are that the conversions of the individual components are carried out with high efficiency (often approaching 95% energy efficiency). However, the disadvantage is that only the carbohydrate fractions (the cellulose and sugar portion of the hemicellulose) can be converted into ethanol. Thus the maximum possible energy efficiency is roughly 60%.

Figure 1

BIOCHEMICAL CONVERSION OF LIGNOCELLULOSIC BIOMASS TO ETHANOL



The four cases we evaluated were: 1) acid hydrolysis and glucose fermentation (commercial), enzymatic hydrolysis and glucose fermentation (pilot scale), and simultaneous cellulose hydrolysis and fermentation with fermentation of the xylose (laboratory and conceptual cases). The processes are summarized below. The key operating parameters are shown in Table 2, the capital investments by process area are shown in Table 3, and the economics are summarized in Table 4.

Commercial Scale Technology – Dilute Sulfuric Acid (Percolation) Technology with Glucose Fermentation The percolation dilute acid hydrolysis process was first developed in Germany in the late 1920s, and improvements were made in the United States, Soviet Union, New Zealand, and Switzerland in the 1940's though early 1980s. At one time, over thirty commercial facilities were in operation in the Soviet Union. The major feature of the system is that it uses a semi-batch, high temperature (150-180ºC), dilute sulfuric acid (0.5 wt%) process to break down the cellulose and hemicellulose into sugars, followed by a standard yeast-based fermentation process using *S. cerevisiae* to convert the glucose into ethanol. Neither of these processes is very efficient. Because the crystalline cellulose is so resistant to chemical attack, conditions severe enough to hydrolyze the cellulose are also severe enough to destroy the product sugars. As a result, the yield is relatively low (63% of the potentially fermentable six-carbon sugars are converted to glucose). The liquid hydrolyzate is neutralized and sent to fermentation. As many of the sugar degradation products are toxic, the fermentation efficiency is relatively low (85%), even though the yeast is quite robust. Perhaps most importantly, the xylose fraction is not fermented to ethanol at all. The overall energy efficiency for ethanol production (heating value of the ethanol/heating value of the wood) is only 20%.

The capital investment per unit of production is quite high (because of the low efficiency, the annual output is low). The cost of production is high $33/GJ ($0.70/liter), and is roughly equally split between feedstock costs and charges related to the capital investment.

Pilot Scale Technology – Iogen Enzymatic Hydrolysis Process Because of the low yields inherent in dilute acid hydrolysis processes, most of the research over the past decade has focused on enzymatic hydrolysis processes. The primary advantage is that enzymes hydrolyze the cellulose to glucose without producing any degradation products. Therefore, the yields can be quite high and no toxic byproducts are produced.

Table I

PERFORMANCE OF BIOMASS TO ETHANOL PROCESSES

	Acid Hydrolysis W/Glucose Fermentation	Enzymatic Hydrolysis w/Glucose Fermentation	Simultaneous Saccharification and Fermentation w/Xylose Fermentation (Base case)	Simultaneous Saccharification and Fermentation w/Xylose Fermentation (Advanced Case)
Pre-treatment	None	Auto-hydrolysis	Dilute Acid	Dilute Acid
Hydrolysis Yield				
C_5 (%)	55%	—	87	87
C_6 (%)	63%	85%	87	—
Fermentation Yield				
C_5 (%)	0	0	90	95
C_6 (%)	85	95	72	90
Energy Efficiency				
Ethanol (%) Ethanol +	20	30	39	50
Electricity (%)	31.3	34	43	54
Annual Production				
liters/yr	109 E6	168 E6	219 E6	280 E6
gallons/yr	28.9 E6	44.4 E6	57.6 E6	74.1 E6
GJ/yr	2.30 E6	3.55 E6	4.63 E6	5.92 E6

Table II

CAPITAL INVESTMENT BY PROCESS AREA FOR BIOMASS TO ETHANOL PROCESSES

	Acid Hydrolysis W/Glucose Fermentation	Enzymatic Hydrolysis w/Glucose Fermentation	Simultaneous Saccharification and Fermentation w/Xylose Fermentation (Base Case)	Simultaneous Saccharification and Fermentation w/Xylose Fermentation (Advanced Case)
Section		**Investment (million $)**		
Feedstock Handling	9.9	14.0	7.2	7.2
Pre-treatment		20.0	23.7	23.7
Enzyme Production		44.0	2.8	1.7
Xylose Fermentation			6.2	3.7
Hydrolysis	22.1	23.0	20.9	8.2
Fermentation	12.6	3.70		
Distillation	20.3	6.05	4.0	4.0
Offsite Tankage	5.8	7.01	4.1	4.6
Environmental Control	18.0	12.0	4.0	3.9
Utilities	46.4	53.3	53.2	46.4
Misc.				2.1
Total Investment	**135.0**	**182**	**128.4**	**105.5**
$/GJ-yr	**58**	**51.2**	**27**	**17.8**

Table III

COST OF PRODUCTION SUMMARIES FOR BIOMASS TO ETHANOL PROCESSES

	Acid Hydrolysis W/Glucose Fermentation	Enzymatic Hydrolysis w/Glucose Fermentation	Simultaneous Saccharification and Fermentation w/Xylose Fermentation (Base Case)	Simultaneous Saccharification and Fermentation w/Xylose Fermentation (Advanced Case)
		($/GJ ethanol)		
Raw Material				
Wood	12.10	3.20	6.05	5.02
Cheese whey		2.10		
Sulfuric Acid and Lime	1.57		0.23	0.23
Chemicals	0.40	1.20	1.10	1.05
Utilities				
Water	0.14	0.10	0.0	0.0
Electricity	–3.70	–1.0	–0.70	–0.50
Labor	0.71	0.50	0.33	0.30
Maintenance	2.04	2.00	0.40	0.52
Overhead	2.10	2.01	1.10	1.01
Insurance, Property taxes	1.05	1.05	0.43	0.30
Total annual operating costs	16.04	15.00	9.10	7.13
Total capital charges (@ 30%)	**17.53**	**15.5**	**8.31**	**5.34**
Cost of Production				
$/GJ	**33.30**	**30.05**	**17.3**	**12.43**
$/l	**0.704**	**0.633**	**0.366**	**0.263**

The Iogen process is a first-generation enzyme-hydrolysis process, and one of only a few which has been run at the pilot scale. This analysis is based on an engineering evaluation carried out for Energy Mines and Resources Canada by Douglas (1989). The Iogen process uses high pressure steam to hydrolyze the hemicellulose and prepare the biomass for the enzymatic hydrolysis process. The necessary enzymes are produced by a highly mutated fungus (*T. reesei*). Unfortunately, the hydrolysis process requires large amounts of enzymes, because the sugars produced during the hydrolysis inhibit the activity of the enzymes. Thus, the enzyme production process is large and expensive, and the hydrolysis process has a relatively low yield (because high yields would take extremely long times or extremely large amounts of expensive enzyme). The glucose is fermented with 95% efficiency to ethanol by *S. cerevisiae*.

The process efficiency is considerably higher than in the previous case (30% energy conversion to ethanol). However, the capital investment is also quite high, primarily due to the high cost of the enzymes, the long hydrolysis time, and the need for a pretreatment process. However, the capital investment per unit of annual capacity is not increased because the investment is spread over a much larger annual production. The cost of ethanol is reduced slightly to $29/GJ or $0.62/liter.

Laboratory and Advanced Technology – Simultaneous Saccharification and Fermentation (SSF) with Xylose Fermentation The SSF process combines the enzymatic hydrolysis and fermentation processes into a single operation. In this process, the yeast converts the sugars to ethanol as soon as they are produced, thus preventing the build-up of sugars which inhibit the activity of the enzymes, and thereby reducing the amount of expensive enzymes which are required. The reaction time is somewhat longer than in the previous case because the introduction of yeast into the hydrolysis process requires that the reaction be run at a lower temperature. The second major innovation is the addition of a xylose fermentation step, which uses a genetically engineered *E. coli* to ferment the xylose to ethanol. This process is now under development in the United States at the National Renewable Energy Laboratory (NREL). All of the major steps have been demonstrated individually, but integrated operation has not yet been reported. This laboratory scale analysis is based on a study of the NREL process by Chem Systems (1990), and the advanced case on an NREL analysis by Hinman *etal*. 1991.

The laboratory scale SSF-xylose fermentation process results in decreased capital investment, due primarily to the reduced enzyme requirements. The investment per unit of production is further reduced because of the increased yield provided by the incorporation of a xylose fermentation process. The laboratory-scale technology converts biomass to ethanol with an efficiency of 39%. The resulting cost of production is \$17.3/GJ or \$0.37/liter.

The overall process for the advanced SSF-xylose fermentation case is identical to the laboratory-scale process. However, in this case the process yields are increased (overall yield based on six-carbon sugars is increased from 72% to 90%), and the xylose fermentation efficiency is increase from 90% to 95%. Also, the time required for the various biological processes are decreased by a factor of two or more. These improvements have not yet been achieved. However, they are representative of what might be achieved with further research and development.

The advanced SSF – xylose fermentation case has a biomass to ethanol efficiency of 53%, and a reduced capital investment. This efficiency approaches the theoretical limit imposed by the composition of the biomass. The projected cost of production is \$12.5/GJ or \$0.26/liter.

THERMOCHEMICAL CONVERSION OF BIOMASS TO METHANOL

The production of methanol from biomass consists of four major processes: 1) gasification of the biomass to produce raw synthesis gas (a mixture of carbon monoxide, hydrogen, carbon dioxide, and water), 2) increasing the H_2/CO ratio to that necessary for methanol synthesis, 3) removal of excess carbon dioxide, and 4) conversion of the carbon monoxide and hydrogen to methanol (Figure 2).

In the gasification process, heat produced by the oxidation of a portion of the biomass

$$C + O_2 \rightarrow CO_2$$

is used to drive the endothermic gasification reactions:

$$C + H_2O \rightarrow CO + H_2$$

$$C + CO_2 \rightarrow 2\,CO$$

The heat may be supplied by supplying oxygen to the gasifier and carrying out the partial oxidation of the biomass in the gasifier itself, or biomass, syngas or char may be burned in a separate combustor and the heat transferred to the bed either through a heat exchanger or a stream of circulating solids. If the partial oxidation is carried out in the gasifier, pure oxygen must be used to minimize the cost of compressing the syngas to the pressure required for methanol synthesis, and to minimize the amount of gas which must be purged to prevent a build-up of inerts in the methanol synthesis process.

The syngas produced in the gasifier has a H_2/CO ratio less than the 2.0 required for methanol synthesis. The H_2/CO ratio is increased in some cases by reforming any methane or hydrocarbons present:

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

and by running the water gas shift reaction, which trades CO for additional H_2

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

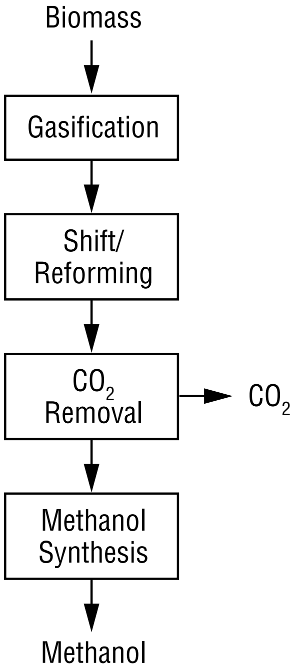
The excess CO_2 and any sulfur containing acid gases are then removed with aqueous potassium carbonate, and the resulting gases are sent to the methanol synthesis process, where the CO and H_2 are combined to produce methanol:

$$CO + 2\,H_2 \rightarrow CH_3OH$$

Because the per pass conversion of syngas to methanol is equilibrium limited, a recycle process is used, where the methanol is separated from the product gases, and the unconverted syngas is returned to the reactor. The methanol is then purified by distillation.

Figure 2

THERMOCHEMICAL CONVERSION OF BIOMASS TO METHANOL



The major advantage of the thermochemical conversion processes is that they use very high temperatures (approximately 1,000°C) to break down the biomass to simple molecules such as CO, CO_2, H_2 and H_2O. Therefore, thermochemical conversion processes are relatively unaffected by the detailed structure of the biomass, and are capable of using the entire feedstock (cellulose, hemicellulose and lignin). The disadvantage of the thermochemical processes is that the practical efficiency of the individual conversion steps is lower. The generation of the raw syngas requires the input of heat at roughly 1,000°C to drive the gasification reactions. Conversely, the methanol synthesis step produces large amounts of heat, but at a much lower temperature (230-300°C). Because of the temperature mismatch, the heat

Table IV

CHARACTERISTICS OF THE BIOMASS TO METHANOL PROCESSES

Technology	Koppers Totzek (Commercial)	Institute of Gas Technology (Pilot)	Battelle-Columbus (Base Case)	Battelle-Columbus (Advanced Case)
Gasifier Type	Direct	Direct	Indirect	Indirect
Heating Mechanism	Partial Oxidation	Partial Oxidation	Circulating Heated Sand	Circulating Heated Sand
Gasification medium	Oxygen-steam	Oxygen-steam	Steam	Steam
Temperature (°K)	1255	1255	1049	1049
Pressure (atm)	1	25	1	1
Cold Gas Yield (corrected for CH_4 shift) m^3/tonne	1360	1485	1510	1510
Methanol Synthesis Technology	Low-pressure	Liquid-Phase	Low-pressure	Low-pressure
Overall biomass to fuel energy efficiency (%)*	40.3	45.4	53.5	53.5
Annual production				
liters/yr	329 E6	384 E6	469 E6	469 E6
gallons/yr	87 E6	102 E6	124 E6	124 E6
GJ/yr	5.2 E6	6.1 E6	7.4 E6	7.4 E6

* The efficiency cannot be directly calculated from the feedstock consumption and the annual methanol production because the process is a significant consumer of imported electricity.

given off in the synthesis process cannot be used to drive gasification. Thus, because biomass must be burned (either in the gasifier or in a separate combustor) to drive the highly endothermic gasification reactions, the theoretical maximum biomass to methanol conversion efficiency is on the order of 52 – 58%, depending on the details of the process.

The four cases we analyzed were 1) Koppers-Totzek (K-T) gasification with low-pressure methanol synthesis (commercial), 2) Institute of Gas Technology (IGT) gasification with liquid phase methanol synthesis (pilot scale), 3) Battelle-Columbus (BCL) gasification with low- pressure methanol synthesis (advanced, base-case), and 4) the BCL gasification low-pressure methanol synthesis process with hot gas clean up (advanced conceptual). The processes are summarized below. The operating characteristics are shown in Table 5, the capital investment in Table 6, and the cost of production summaries are presented in Table 7.

Commercial Scale Technology – Koppers Totzek Gasification – Low Pressure Methanol Synthesis The commercially available Koppers-Totzek gasifier was originally developed for use with coal, and approximately 50 have been built worldwide over the past 40 years. Most of these installations use lignite or heavy naphtha as a feedstock. The gasifier has been tested on wood, but there are no commercial integrated wood-to-methanol processes in operation. The gasifier is coupled to a low-pressure methanol synthesis process of the type sold by Lurgi and Imperial Chemical Industries (ICI), which account for over 90% of the world’s installed methanol capacity. The analysis of this system is based on a study carried out by Chem Systems (1989) for the United States Department of Energy.

The K-T gasifier is an oxygen-blown, atmospheric pressure, entrained-bed design. Because it uses extremely short residences times, extensive grinding is used to reduce the size of the feedstock, and the biomass must be dried to 5% moisture. Because the heat needed to drive the gasification process is produced by partial oxidation inside the gasifier, an expensive oxygen plant is required. After gasification, the raw syngas is cooled to ambient, and the particulates and tars are removed. The syngas is reheated to run the water gas shift reaction, and the gases are again cooled before they enter the CO_2 removal unit. Finally, the syngas is compressed and sent to methanol synthesis.

While the overall biomass-to-fuel conversion efficiency of this process is quite respectable (40%), the capital investment of $325 million or $62.4/GJ-yr is very large (approximately twice that of the ethanol production processes). This is a result of the very expensive gasifier used, the large drying and grinding costs, the need for an oxygen plant, the need to compress large gas streams to the methanol synthesis temperature, and the multiple

Table V

CAPITAL INVESTMENTS FOR THE THERMOCHEMICAL CONVERSION OF LIGNOCELLULOSE TO METHANOL

Technology	**Koppers Totzek (Commercial)**	**Institute of Gas Technology (Pilot)**	**Battelle-Columbus (Advanced Base Case)**	**Battelle-Columbus (Advanced Conceptual Case)**
		Investment (million $)		
Feedstock Preparation	38.3	17.1	20.3	20.3
Oxygen Plant	49.9	43.3		
Gasification	97.5	29.4	7.9	7.9
Solids Removal		0.8	1.7	12.8
Shift/Reforming	0.8	31.9	41.3	0.03
Acid Gas Clean-up	11.1	11.8	11.6	11.6
Gas Cooling		2.0		
Syngas Compression	10.9	8.2	25.7	25.6
Methanol Synthesis	21.4	24.2	32.2	32.2
Utilities, Offsites	57.4	42.2	35.2	27.6
Land, Owners costs, fees, profit, start-up cost	37.3	29.7	23.2	20.0
Total Cost	**324.6**	**240.6**	**199.2**	**158.2**
Cost/Unit of annual production ($/GJ-yr)	**62.4**	**39.1**	**26.5**	**20.8**

heating and cooling cycles to which the gas is subjected. Thus, the cost of production is dominated by the charges related to the capital investment, and feedstock costs play only a minor role in the economics. The cost of production is \$28.5/GJ or \$0.45/liter.

Pilot Scale Technology – IGT Gasification – Liquid Phase Methanol Synthesis This process uses the Institute of Gas Technology "Renugas" gasifier, coupled to an Air Products/Chem Systems liquid-phase methanol synthesis process. Both of these processes have been demonstrated individually at the 10 tons/day scale. This portion of the analysis is also based on the Chem Systems (1989) report used in the previous case. The IGT gasifier is a fluidized-bed, partial oxidation unit. As such, it uses larger residence times and can use a wood chip feedstock directly (without excessive and expensive grinding), and does not require an extremely dry feedstock. The gasifier is operated at pressure, and thus the overall compression costs are slightly reduced because feeding pressurized solids into a gasifier requires less energy than compressing the large volumes of gas produced from the solids during gasification. Because the gasifier is run at pressure, the syngas produces a moderate amount of methane, which must be reformed to produce additional CO and H_2. Although this process is expensive, it increases the overall yield. The gases are again subjected to multiple heating and cooling cycles to remove the tars, particulates, and CO_2. The liquid phase methanol synthesis provides better temperature control and slightly better per pass conversion, and has economics which may be slightly superior to the standard low pressure process.

The overall conversion efficiency of the process is increased to 45%, and the capital investment is reduced as well. The cost of production is still dominated by the capital investment (\$39/GJ-yr), to which the oxygen plant is a major contributor. The cost of production is reduced to \$20.1/GJ or \$0.31/liter.

Advanced Systems: Battelle-Columbus Gasifier – Low Pressure Methanol Synthesis The major improvement in the advanced system is the use of the indirectly heated BCL gasifier, which eliminates the need for the oxygen plant (because the heat is transferred from the combustor to the gasifier by a circulating bed of sand, the combustor can use air instead of oxygen). Because of the indirect design, the BCL gasifier produces large amounts of methane and hydrocarbons, which increases the yield but also requires a large capital investment in the reformer. The remainder of the process is similar to the previous systems.

Table VI

COST OF PRODUCTION FOR THE THERMOCHEMICAL CONVERSION OF BIOMASS TO METHANOL

Technology	**Koppers Totzek (Commercial)**	**Institute of Gas Technology (Pilot)**	**Battelle-Columbus (Base Case)**	**Battelle-Columbus (Advanced Case)**
Raw Materials				
Wood	5.72	5.03	4.01	4.01
Chemicals	0.10	0.28		
Utilities				
Electricity	0.40	0.40	1.50	1.10
Steam		–0.19		
Cooling Water	0.01	0.03		
Feedwater	0.01	0.04		
Fuel		0.20		
Other variable costs			0.44	0.44
Labor	0.20	0.15	0.12	0.12
Maintenance	1.52	1.05	0.60	1.03
Overhead	1.50	0.82	0.50	0.60
Insurance, Property taxes	1.14	0.60	0.40	0.31
Total annual operating costs	**9.65**	**8.01**	**6.54**	**6.50**
Total capital charges (@ 30%)	**19.01**	**12.10**	**8.30**	**6.42**
Cost of Production				
$/GJ	**28.50**	**20.10**	**14.70**	**13.10**
$/l	**0.448**	**0.311**	**0.231**	**0.204**

The increased yield brought about by the reforming of the hydrocarbons increases the conversion efficiency to 53%, approaching the theoretical limit for such processes. Largely because of the elimination of the oxygen plant, the capital cost is also reduced, as is the investment per unit of production ($29/GJ-yr). The cost of production is $14.7/GJ, or $0.23/liter.

The advanced-case system uses the same gasifier and methanol synthesis process, but adds hot gas clean-up technology (developed for use with coal gasifiers) to eliminate much of the repeated heating and cooling of the syngas. By using high temperature particulate and tar removal, the hot raw syngas can be fed directly to the reformer. This not only reduces heat exchange costs, but also eliminates a major steam consumption. (In previous processes the steam in the raw syngas was condensed out when the gases were cooled before the particulate-removal step, and high pressure steam was then added before the syngas entered the reformer/water-gas shift reactor.)

The advanced case has a reduced capital investment ($18/GJ-yr) and an efficiency identical to the previous BCL-based system. The cost of production in the advanced case is projected to be $13.1/GJ or $0.20/liter.

COMPARISON OF METHANOL AND ETHANOL PRODUCTION FROM BIOMASS

The cost of production of methanol and ethanol from biomass is shown on an energy basis in Figure 3. The graphs show quite clearly that the economics are dominated by the capital investment, and secondarily by the feedstock costs. The decreasing costs of the ethanol processes were driven by the improvement in yield from case to case, which both reduced the feedstock cost and spread the capital investment over a larger base of production. The improvements in the methanol cases were brought about by simplifying the process (eliminating expensive processing steps) and only secondarily by improving the yield (which started out relatively high).

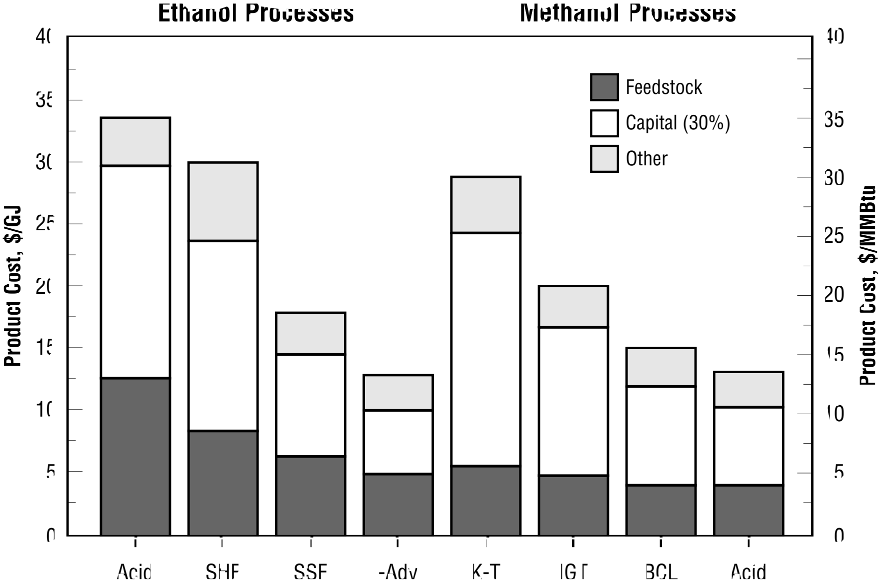
In an overall sense, capital investment per unit of production is similar for the biochemical and thermochemical processes. We see that the investment per unit-of-annual-capacity is similar at all stages of development. There is no fundamental reason for this, it merely suggests that equivalent results can be achieved with slow processes which operate in large vessels at low temperatures and pressures, and rapid processes which require only small vessels but operate at high temperatures and pressures.

When comparing the two types of processes, it is instructive to look not only at the cost of production, but simultaneously at the uncertainty of the estimate. Figure 4 shows the cost of methanol and ethanol with uncertainty bars taken from the previous sensitivity analysis. The important conclusion of the analysis is that for the processes which have been demonstrated at the commercial and pilot scales, methanol production is considerably less expensive than ethanol production. However, for the laboratory scale processes there is little difference, and for the “conceptual” processes which attempt to estimate the limits of process improvement, the economics of the methanol and ethanol production are virtually identical.

This result is a direct outgrowth of the basic nature of the biomass feedstock, and the fundamental characteristics of the two types of processing. The ethanol processes convert the carbohydrate fraction of the biomass (which accounts for roughly 60% of the energy content of the feedstock) to ethanol with an extremely high efficiency (roughly 85%, compared with a theoretical limit of 95%). Thus, the overall efficiency of converting biomass to ethanol is approximately 50%. In contrast, because of the temperature mismatch between the endothermic gasification process (which requires heat at

Figure 3

COST OF PRODUCTION BREAKDOWN FOR METHANOL AND ETHANOL FROM BIOMASS

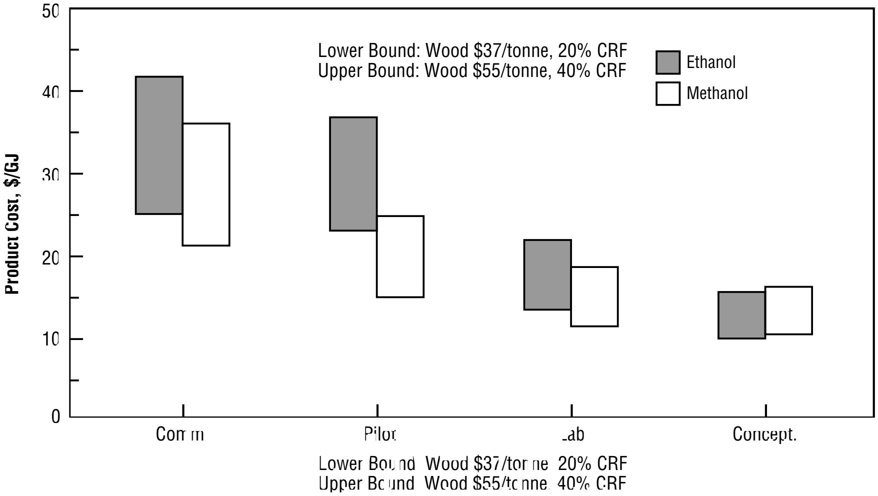


1,000ºC) and the exothermic methanol synthesis process (which produces heat at only 230-300ºC), the maximum efficiency of the thermochemical conversion process is only 52-58% (depending on the detailed assumptions). However, because the gasification process operates at high temperatures and converts all fractions of the biomass to simple molecules such as CO, CO_2, H_2 and H_2O, from which the methanol is synthesized, the methanol synthesis processes can use all fractions of the feedstock, not just the carbohydrate fraction. A thermochemical process which achieves 90% of the theoretically possible 58% efficiency therefore has an overall process efficiency of a little better than 50%. Thus, the ultimate efficiencies of the processes which produce methanol and ethanol from biomass are essentially identical.

Sensitivity analyses were carried out to determine the influence of the major assumptions (plant size, feedstock cost, and capital recovery factor) on the cost of production, and to determine whether changes in any of these assumptions would have affected the conclusions of the study. In general, the economics of ethanol production are more sensitive to changes in feedstock cost, while the more capital intensive thermochemical processes are more sensitive to the assumed capital recovery factor or the size of the plant. However, we found that the conclusions of this study are unchanged over a very wide range of plant scales, feedstock costs, and economic assumptions.

Figure 4

COMPARISON OF THE ECONOMICS OF METHANOL AND ETHANOL FROM BIOMASS



In summary, the economics of near-term thermochemical methanol synthesis processes are superior to those of the near-term biochemical process. This is a direct result of the lower conversion efficiencies of the near-term biochemical processes, due to the inability of the early designs to ferment the five-carbon sugars (xylose) to ethanol. For the advanced cases, the economics of methanol and ethanol are essentially identical, which results from the fact that the limiting conversion efficiencies of the biochemical and thermochemical conversion processes are essentially the same. With equivalent efficiencies and no significant differences in the capital investment, the ultimate economics of both processes are the same.

Part V

Summary of the Greenhouse Gas and Other Emissions to Air Resulting from Ethanol and Methanol Use as Alternative Fuels

January 1995

Study performed by:
Ortech Corporation
Mississauga, Ontario

SUMMARY OF THE GREENHOUSE GAS AND OTHER EMISSIONS TO AIR RESULTING FROM ETHANOL AND METHANOL USE AS ALTERNATIVE FUELS

BACKGROUND

Radiation from the sun is re-emitted by the earth as heat energy. Greenhouse gases are atmospheric gases that tend to absorb the heat radiating from the earth. The main contributor to the greenhouse effect is carbon dioxide (CO_2). The concentration of these gases in the atmosphere is increasing due to the inability of the earth's sinks to absorb them at the same rate as they are being generated. The increasing concentration of these gases in the atmosphere is causing the phenomenon known as global warming as the excess heat from the earth is not allowed to be emitted back into space.

Carbon dioxide, which accounts for approximately 55% of the relative contribution to greenhouse enhancement is released at a rate of approximately 30 billion tons per year worldwide. The primary sources of excess anthropogenic CO_2 are fossil fuel combustion, including both stationary and mobile sources, deforestation, and other industrial processes such as cement production.

INTRODUCTION

A literature search was conducted by ORTECH to review previous studies on the effects (relative to greenhouse gas emissions) of substituting methanol and ethanol for gasoline and diesel as transportation fuels. Greenhouse gas emission estimates for the total fuel cycle (feedstock extraction, production, distribution, and use) were investigated.

The relevant greenhouse gas emissions that are produced during the transportation fuel cycle include:

Carbon dioxide	CO_2
Methane	CH_4
Nitrous oxide	N_2O
Non methane organic compounds	NMOC

Although chlorofluorocarbons could in theory be, and in practice often are released from automobiles, especially their air conditioning systems, these were not considered further in this study.

Six different processes for producing methanol and ethanol were identified:

Derived from Fossil Fuels:

- Methanol from Natural Gas
- Methanol from Coal
- Ethanol from Petrochemicals

Derived from Biomass Feedstocks:

- Ethanol from Corn
- Methanol and Ethanol from Cellulosic Biomass

LITERATURE REVIEW/INFORMATION UPDATE

Different studies have been conducted on the global environmental impact of the use of methanol and ethanol as alternative fuels and the associated greenhouse gas emissions expressed as CO_2-equivalents (DeLuchi et al., Unnasch et al., Ho and Renner). CO_2-equivalents were calculated using global warming potential factors. These studies have looked at the full cradle-to-grave impact of the substitution of these fuels including emissions associated with feedstock extraction (or production), fuel production, distribution and end use (vehicle emissions).

Results from the Literature Review

The following table was taken from a report by M.A. DeLuchi, 1991 and shows a wide range of results for the greenhouse impact of methanol and ethanol relative to gasoline. For the most part, the results from the other studies that were reviewed fall within these wide ranges. The range of results demonstrates the variability arising from the best and worst case assumptions for each of the given fuel cycles. Due to this level of variability in the estimations, it became apparent that few conclusions could be made as to the impact of each of the methanol and ethanol processes relative to gasoline and diesel without attempting to address the reasons for the discrepancies.

Table 3.1

RANGE OF FINAL RESULTS OF GREENHOUSE IMPACT OF METHANOL AND ETHANOL FUEL CYCLE RELATIVE TO GASOLINE FUEL CYCLE

Fuel Cycle	Percentage Change in Total Emissions
Gasoline	0%
Methanol from Natural Gas	−25% to 12.5%
Methanol from Coal	10% to 75%
Methanol from Wood	−100% to −5%
Ethanol from Wood	−100% to 12.5%
Ethanol from Corn (+Coal)	−65% to 80%
Ethanol from Corn (+ Corn Stover)	−70% to 0%

(DeLuchi 1991)

Data have been extracted from the 1991 Deluchi report and are presented in Table 3.2 and Figures 3.1, 3.2, 3.3 and 3.4. The data are deemed to represent fair approximations based on currently available comparable studies but have not been validated.

The emissions from each fuel cycle are presented in grams of carbon dioxide equivalents per litre of fuel. The per litre basis (as opposed to per mile) was chosen to diminish the possible uncertainty that may arise with the choice of fuel mileage values. Ethanol and methanol were given fuel mileage values of 19 mpg and 14 mpg, respectively by Deluchi but these values may change significantly with new dedicated test vehicles.

The greatest total impact is seen as being produced by the methanol from coal and ethanol from corn fuel cycles in Figure 3.1. Figures 3.2-3.4 present the fuel cycle stages where the greatest relative emission impacts are more clearly shown. Feedstock recovery refers to natural gas extraction, coal mining, and wood and corn cultivation.

The feedstock recovery stage of the ethanol from corn cycle contributes a significant portion of the total fuel cycle emissions as seen in Figure 3.2. This is due to the energy-intensive cultivation practices and releases of nitrous oxide from fertilized soils.

Figure 3.3 shows the high relative impacts of the methanol from coal and ethanol from corn production stages due to their low process conversion efficiencies. The ethanol from wood cycle indicates a negative emission impact on the production stage due to the excess energy that can be produced by the burning of the lignin portion of the wood.

Vehicles that use methanol fuel have similar emissions, but when the total fuel cycle is considered, the feedstock for the fuel becomes important to the overall net impact As shown in Figure 3.4, the fossil fuel derived fuels (methanol from natural gas and coal) do not benefit from the carbon dioxide credit for biomass and therefore demonstrate a greater impact for the vehicle emissions stage than the biomass derived fuels.

Table 3.2

TOTAL FUEL CYCLE EMISSIONS FOR LIGHT DUTY FLEET (g CO_2-equivalent/L)

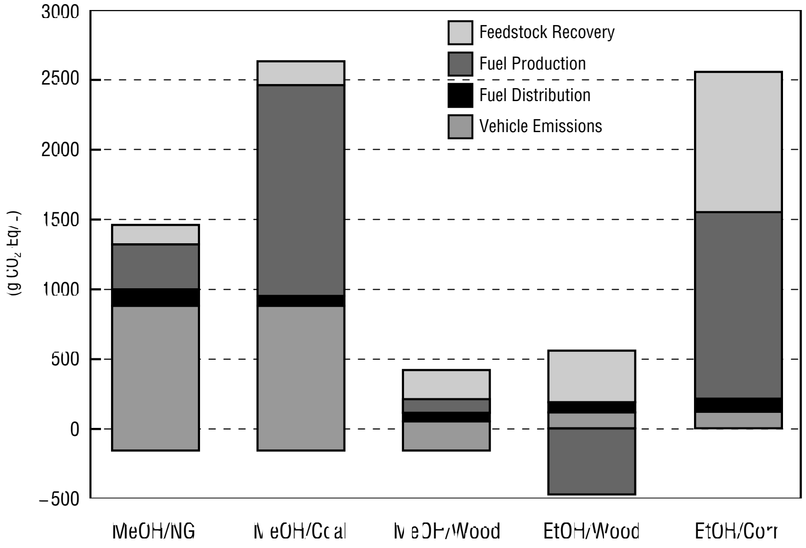
	MeOH / NG	MeOH / Coal	MeOH / Wood	EtOH / Wood	EtOH / Com
Feedstock Recovery					
Mining	70	30			
– Releases	40	140			
– Equipment					
Cultivation			170	300	930
– Release					
– Equipment					
Transmission	40	10	40	70	80
Total Feedstock	150	180	210	370	1010
Fuel Production					
Process Heat					
Electrical					
Process Efficiency					
Total Production	310	1500	90	-320	1310
Fuel Distribution					
Transportation					
Storage					
Total Distribution	110	60	70	70	100
Vehicle Emissions	1030	1030	190**	260**	260**
Total Fuel Cycle Emissions	1600	2770	560	380	2680

** Carbon dioxide credit for biomass is included.

(Reference Deluchi, 1991)

Figure 3.1

TOTAL FUEL CYCLE EMISSIONS



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*Carbon dioxide credit for biomas included

Figure 3.2

FEEDSTOCK RECOVERY EMISSIONS

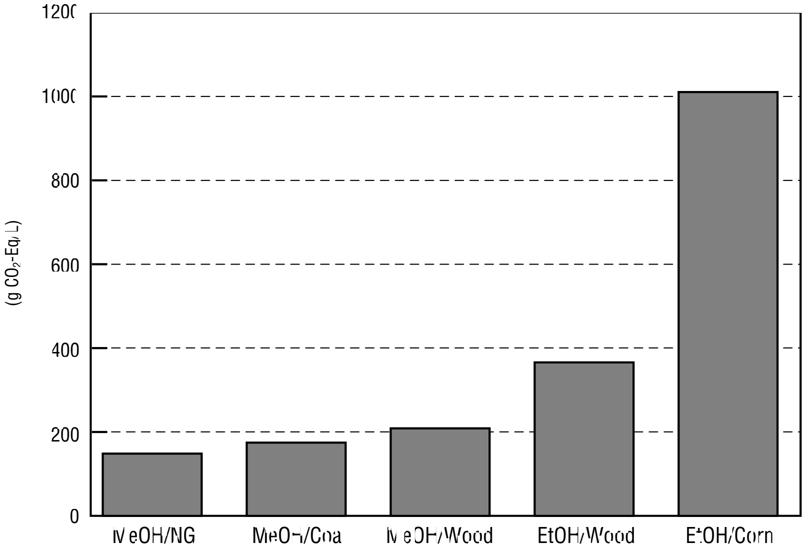
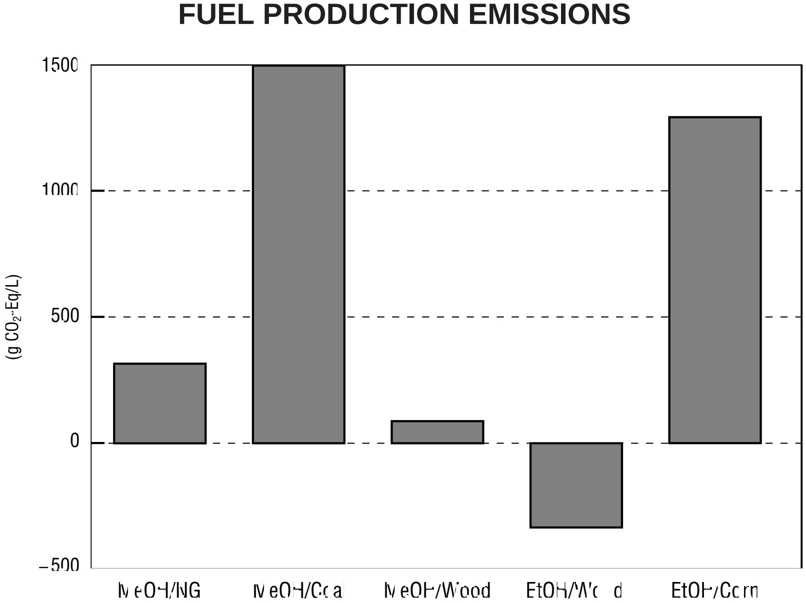
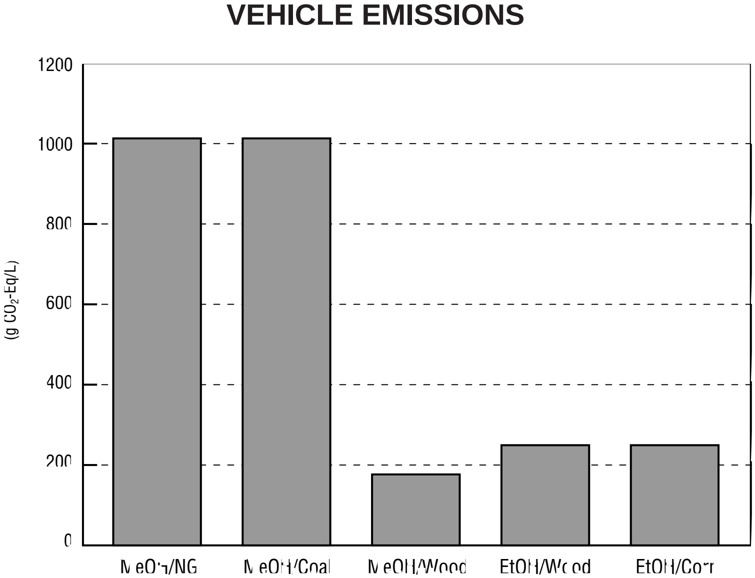


Figure 3.3



*Carbon dioxide credit for biomas included

Figure 3.4



*Carbon dioxide credit for biomas included

Methodologies Used to Estimate Greenhouse Gas Emissions

Greenhouse gas impact investigators have used a variety of methods to estimate greenhouse gas emissions. The use of these different techniques, which arise because of varying available information, has resulted in the wide range of emission estimates.

The different estimation methodologies are listed below:

- Carbon Balance
- Energy Content of Fuel
- Process Efficiencies
- Thermal Efficiencies
- CO_2-Equivalence Based on Global Warming Factors
- Estimations Based on Limited or No Data
- Future Technical Advances Projections

Common Conclusions from the Literature Review

In reviewing the literature, it became apparent that a number of conclusions were common to most studies. Even with the different approaches carried out by the researchers and the often conflicting assumptions, it is significant to note these similar statements. The following are some of the common conclusions from the studies:

1. The most feasible approach to reducing greenhouse gas emissions is through the reduction in the use of fossil fuels. Fossil fuels release historic carbon that is in excess of the environment's ability to absorb carbon dioxide.

2. The use of methanol from coal will result in the generation of a greater amount (up to a 100% increase) of greenhouse gas emissions than the use of conventional fuels.

3. The use of methanol from biomass or ethanol from corn or biomass may result in a decrease in the generation of greenhouse gas emissions relative to the use of conventional fuels. This is due to the credit that is given for the carbon dioxide that is consumed by the plant matter during its life.

4. Any CO_2 generated by the end use burning of renewable biomass fuels is not considered to cause a net increase in the level of CO_2 in the atmosphere because it was originally taken from the atmosphere by the biomass.

5. The use of methanol or ethanol from woody biomass is considered superior to ethanol from corn due to other less energy-intensive cultivation practices of woody crops.
6. Process energy for the production of ethanol from woody biomass can be derived from lignin (a waste product of the process). This will reduce the impact of emissions from other sources of process energy such as coal, oil or gas.

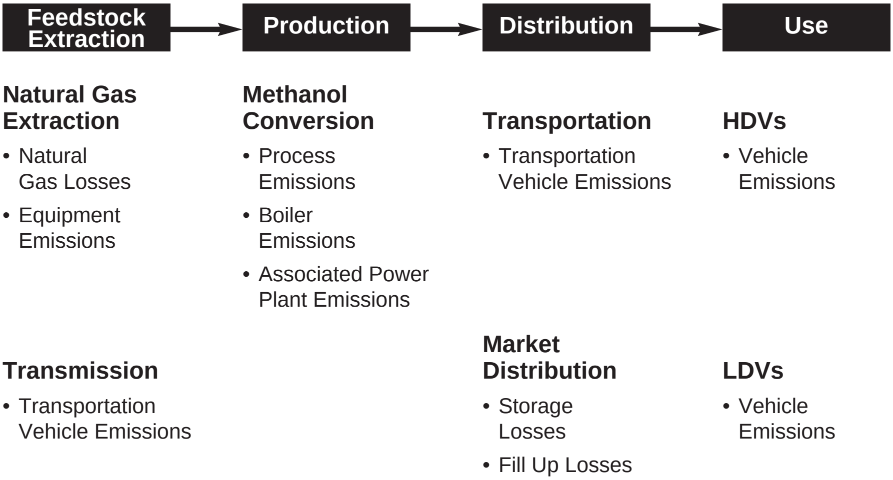
GREENHOUSE GASES FROM METHANOL AND ETHANOL PRODUCTION

Methanol from Natural Gas

Greenhouse gases are emitted from many sources associated with the extraction, processing, transmission and distribution of natural gas prior to and then include the methanol or ethanol processing facilities. The natural gas processing industry comprises all facilities and operations that are used to develop, produce, gather, treat/process and transport natural gas from fields to processing plants and onto distribution systems and consumers. In this situation, the consumer is a petrochemical plant which processes the natural gas to methanol. Figure 4.1 presents a schematic of the methanol from natural gas production system.

Figure 4.1

METHANOL FROM NATURAL GAS PRODUCTION

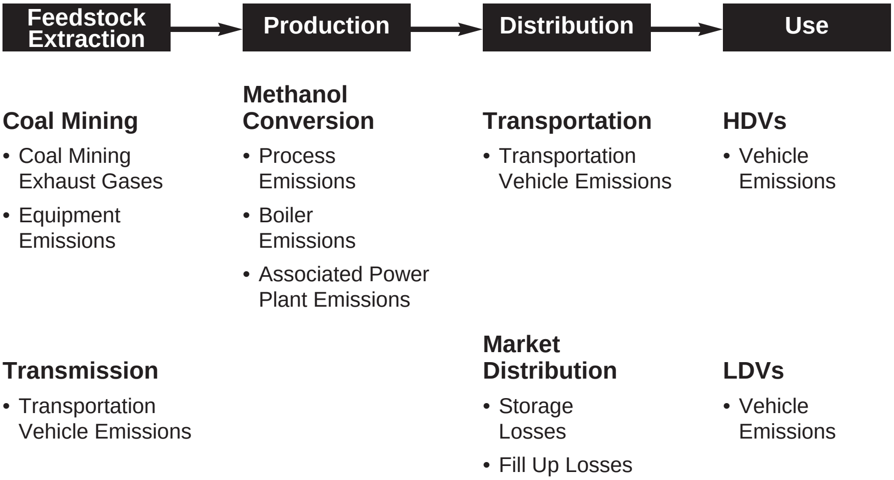


Methanol from Coal

During the mining and transporting of coal, the methane present in the coal is released. The mining of coal is a major anthropogenic source of methane. Coal mining operations include underground and surface mines, coal handling and transportation and abandoned mining facilities. Figure 4.2 presents a schematic of the methanol from coal production system.

Figure 4.2

METHANOL FROM COAL PRODUCTION



Methanol and Ethanol from Biomass Feedstocks

Methanol and ethanol production using biomass feedstocks was investigated and the greenhouse gases emissions discussed and presented in the following sections. Ethanol production from corn, and methanol and ethanol from biomass feedstocks such as wood are presented.

The fuel cycle for methanol or ethanol from biomass is shown in Figure 4.3. The major sources of greenhouse gas emissions are shown for each stage of the cycle. The magnitude of greenhouse gas emissions from biomass feedstock derived fuels is strongly dependent on cultivation methods and conversion processes.

Figure 4.3

METHANOL AND ETHANOL FROM BIOMASS

Fertilization
- Fertilized Soil Emissions
- Equipment Emissions
- Fertilizer Production

Irrigation
- Equipment Emissions

Pesticide Use
- Equipment Emissions
- Pesticide Production

CO_2 Consumption by Biomass

Transmission
- Transportation Vehicle Emissions

Methanol Conversion
- Process Emissions
- Boiler Emissions
- Associated Power Plant Emissions

Transportation
- Transportation Vehicle Emissions

Market Distribution
- Storage Losses
- Fill Up Losses

HDVs
- Vehicle Emissions

LDVs
- Vehicle Emissions

METHANOL AND ETHANOL FUELLED VEHICLE EMISSIONS

Table 5.1 shows typical values for greenhouse gas emissions from light duty vehicles expressed as CO_2-equivalence in grams per mile. The total CO_2-equivalent vehicle emissions do not vary tremendously between the three fuels but the significance of the CO_2 portion of the emissions differs greatly depending on the feedstock that was used.

Table 5.1

CO_2-EQUIVALENT EMISSIONS FOR LIGHT DUTY VEHICLES

(g/mi)

	CO_2	N_2O	CH_4	Total
Gasoline	260	20	0.6	280.6
Methanol	215	20	0.6	235.6
Ethanol	230	20	0.6	250.6

(DeLuchi 1991, Ho & Renner, 1990)

The CO_2 generated by vehicles using biomass-derived ethanol and methanol is not considered to cause a net addition of CO_2 to the atmosphere as it is considered to be the same CO_2 that was consumed by the biomass when it was growing. If the CO_2 portion of the emissions is then not considered to have an impact on greenhouse gas accumulation, then the vehicle emissions will vary tremendously as shown in Table 5.2. The CO_2 generated by vehicles using fossil fuel-derived ethanol and methanol will contribute to the increasing concentration of CO_2 in the atmosphere as there are no offsetting factors.

Table 5.2

CO_2-EQUIVALENT EMISSIONS FOR LIGHT DUTY VEHICLES (CO$_2$ FROM COMBUSTION IS RECYCLED TO BIOMASS)

(g/mi)

	CO_2	N_2O	CH_4	Total
Gasoline	260	20	0.6	280.6
Methanol (fossil)	215	20	0.6	235.6
Methanol (biomass)	0	20	0.6	20.6
Ethanol (biomass)	0	20	0.6	20.6

The greenhouse gas credit obtained for methanol and ethanol derived from biomass is significant when dealing with the entire fuel cycle. The greenhouse gas emissions from vehicles using biomass-derived methanol and ethanol as fuel represent a much smaller proportion of the total greenhouse gas emissions from these fuel cycles relative to gasoline and diesel fuel cycles. Therefore, the emissions from the feedstock extraction and conversion processes become the major sources of greenhouse gas emissions for these fuel cycles.

SCENARIO COMPARISON

Two scenarios have been chosen for comparison of the total fuel cycle impact of greenhouse gases. The feedstock for both scenarios is the fossil fuel natural gas. The first scenario consists of an electric vehicle that obtains its electrical recharge from a natural gas fired power utility. The second scenario consists of a methanol vehicle where the methanol was produced from natural gas. Estimations of the total fuel cycle impact are presented along with the identification of the major sources of greenhouse gas emissions.

Scenario I: Electric Vehicle/Natural Gas Utility

Scenario I refers to the total greenhouse impact of an electric vehicle that is deriving its electrical charge from a natural gas fired utility. It is assumed that this scenario is for the future and, therefore, projections of future efficiencies will apply.

Efficiency of electric vehicles is a function of both the powertrain technology and of how the vehicle is used. Technical efficiency is dependent on the vehicle weight and efficiency of the battery, recharger and drivetrain. Efficient use of electric vehicles is determined by city driving versus highway driving and the avoidance of recharging after shallow discharge.

For electric vehicles being recharged by electricity generated by natural gas-fired utilities, the reported range of the potential change in greenhouse gas emissions relative to gasoline is between – 75% and +15%. This range refers to best case and worst case projections (DeLuchi, 1991). The ‘best estimate’ case predicts an approximate 30% decrease in greenhouse gases relative to gasoline.

The major sources of greenhouse gas emissions resulting from this scenario include; natural gas extraction, natural gas transmission and natural gas combustion at the power utility. Other sources include N2O emissions from power transmission lines. To a lesser extent, emissions associated with vehicle construction and nitrous oxide emissions formed by the corona discharge from high-voltage power lines will contribute to the greenhouse gas impact. If it is assumed that electric vehicles are to make up the majority of the fleet then the nitrous oxide emissions from power lines may have a significant impact as the use of power lines increases.

Methane releases from feedstock extraction and transmission will have the greatest greenhouse gas impact for this scenario. The impact of the carbon dioxide releases will be directly proportional to the efficiency of the power utility and the efficiency of the battery recharging. The impact of methane and nitrous oxide emissions resulting from this scenario will be greatly affected by the global warming factors that are applied.

Scenario II: Methanol Vehicle/Methanol Derived from Natural Gas

Scenario II refers to the total greenhouse impact of a methanol fuelled vehicle where the methanol was produced from natural gas. For comparative purposes, it is assumed that this scenario is also for the future and therefore a dedicated methanol vehicle is assumed. Dedicated methanol vehicles are expected to use methanol fuel more efficiently than flexible fuel vehicles.

For a methanol fuelled vehicle where the methanol was produced from natural gas, the reported range of the potential change in greenhouse gas emissions relative to gasoline is between – 25% and +12%. This range refers to best case and worst case projections (DeLuchi, 1991). The ‘best estimate’ case predicts an approximate 4% decrease in greenhouse gas emissions relative to gasoline.

The major sources of greenhouse gas emissions resulting from this scenario include; natural gas extraction, natural gas transmission, methanol conversion process, process heat, associated utility emissions, methanol distribution, and vehicle emissions.

Scenario Discussion

For the most favourable circumstances a ‘best estimate’ prediction for each scenario, Scenario I is predicted to have the greatest potential for the lowest greenhouse gas impact for the total fuel cycle. The ‘best estimate’ case predicts that Scenario I could effectively reduce greenhouse gas emissions by 30% relative to gasoline while Scenario II could achieve a ‘best estimate’ reduction of 4%. The difference between the two fuel cycles being the efficiency of the conversion process and utilization of the fuel. The efficiency of converting natural gas to electrical power in a utility power plant and then the use of an electrical vehicle is more efficient than the conversion of natural gas to methanol and the use of a methanol fuelled vehicle.

CONCLUSIONS

This literature study of the five ethanol and methanol fuel cycles determined the following:

1. For methanol vehicles where the methanol was derived from natural gas, the major sources of greenhouse gas emissions is the vehicle emissions.
2. For methanol vehicles where the methanol was derived from coal, the major sources of greenhouse gas emissions are the processing of mined coal and the vehicle emissions.
3. For ethanol vehicles where the ethanol was derived from corn, the major greenhouse gas emissions are from the corn cultivation and the conversion processes. Nitrogen fertilizers and fossil fuel equipment contribute to the cultivation emissions, while fossil fuels for the conversion process further add to the greenhouse gas emissions.
4. Ethanol and methanol from biomass or wood had the greatest potential for reducing greenhouse gas emissions.
5. The use of biomass derived fuel greatly reduces the emission of carbon dioxide. The amount of carbon dioxide released from the combustion of biomass derived fuels is not greater than the amount absorbed from the atmosphere by the original living biomass. This discounts the vehicle greenhouse gas emissions for biomass derived fuel vehicles.
6. Although biomass derived ethanol and methanol fuels have the greatest emission reduction potential, biomass cultivation and conversion technologies for large-scale supply are just developing. At this stage in technology development, the greenhouse gas emissions are only estimates. Also, the timely implementation of these fuels is hindered by the lack of available proven technology.

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3. Ho, S.P., and T.A. Renner, “Global Warming Impact of Gasoline vs. Alternative Transportation Fuels”, SAE Technical Paper Series No. 901489, Society of Automotive Engineers, Warrendale, PA, 1990.

Part VI

Conclusions of Annex IV/Phase II Studies and Operating Agent's Recommendations

CONCLUSIONS OF ANNEX IV/PHASE II STUDIES AND OPERATING AGENT'S RECOMMENDATIONS

Although the conclusions of each of the four studies have been provided earlier, in the individual summary sections, a few of the overall conclusions merit mention here.

The "**Natural Gas Supply, Demand and Price**" study showed that there are many locations around the world where natural gas reserves are underutilized. These represent a large pool of potential raw material for fuel methanol production, as well as for pipeline or LNG export. Because methanol is comparatively inexpensive to transport over long distances by tanker, the economics of its production are less sensitive to distance than those of pipeline gas or LNG. Consequently, a fuel methanol supplier has a great deal of latitude to seek out low cost gas feedstock anywhere in the world.

Just four countries – the former U.S.S.R., Iran, Abu Dhabi, and Qatar – account for 75 percent of the world's exportable gas surplus. But a number of others have large enough blocks of exportable reserves for gas export projects to be under active consideration. In order of exportable reserve size, they include Nigeria, Norway, Australia, Indonesia, Algeria, Malaysia, Venezuela, and Trinidad.

There are several locations in which gas could be produced at a cost of service below $0.50/MMBtu (in 1990 dollars). They include Sumatra, and Kalimantan, Indonesia; Tierra del Fuego, Chile; non-associated gas in Nigeria, and Qatar and Abu Dhabi in the Middle East. However, the gas would not be available to a new methanol plant on this basis.

Nevertheless, allowing for the market value of gas and the host country's take, the locations above and several others such as Australia and Bangladesh in the Far East; Venezuela and Argentina in Latin America; Algeria and Iran could supply gas to a methanol fuel plant at a price of less than $1.00/MMBtu (in 1990 dollars). Over time this price could rise, depending on assumptions about alternate gas market values.

In the "**Economic Comparisons of the LNG, Methanol and Synthetic Distillate**" study, a full range of cif costs were calculated, which made possible the ranking, in order of preferred sources, of a particular product (LNG, Methanol and Synthetic Distillate) for a particular market (Tokyo, Rotterdam, and U.S. Gulf Coast).

Cross-product comparisons by gas source in any given market indicated that where country gas prices were low, there was room to trade-off the higher conversion losses associated with either methanol or middle distillate gas conversion (combined with lower per-mile transport costs) in order to supply more distant markets. Very high cost gas sources, especially when combined with high site penalties (such as the Natuna field offshore Indonesia), quickly became economically unattractive when high conversion losses or long distance transport costs were added.

The "**A Comparison of the Production of Methanol and Ethanol from Biomass**" study provided the important conclusion that for processes which have been demonstrated at the commercial and pilot scales, methanol production is considerably less expensive than ethanol production. However, for the laboratory scale processes there was little difference, and for the "conceptual" processes which attempted to estimate the limits of process improvement, the economics of the methanol and ethanol production were virtually identical.

The "**Greenhouse Gas and Other Emissions to Air Resulting from Ethanol and Methanol Use as Alternative Fuels**" study showed that the total CO_2-equivalent vehicle emissions (expressed in grams/mile) did not vary much between gasoline, methanol and ethanol fuel, but the significance of the CO_2 portion of the emissions differed greatly depending on the feedstock that was used for its production.

For fossil fuel-derived methanol or ethanol, the CO_2-equivalent vehicle emissions were similar (235.6 and 250.6 g/mi versus 280.6 for gasoline). The use of biomass derived fuel greatly reduced the emission of carbon dioxide (to 20.6 g/mi for both methanol and ethanol).

THE OPERATING AGENT'S MANDATE

The mandate given to the Operating Agent (page 2 of this report) has been fulfilled. The expenses incurred for Annex IV/Phase II were within the envelope established by the Executive Committee of the IEA Alternative Motor Fuels Agreement at its meeting of November 17, 1989.

Publication of this Final Report meets the Operating Agent's last responsibility.

RECOMMENDATIONS

The studies performed in Annex IV/Phase II amply demonstrate that feedstock availability for production of alternative fuels is not of concern, especially with regard to fossil fuel-based processes.

The production cost of alternative fuels, including the costs of the feedstock, processing and transportation, have been provided for a large number of locations around the world.

The environmental benefits, as expressed in CO_2-equivalent vehicle emissions, showed a great reduction for biomass derived fuels, but minor variations for fossil fuel-based alternative fuels.

In consideration of the above, the Operating Agent makes the following recommendation:

The IEA Alternative Motor Fuels Agreement should consider that its investigations in the production of alcohols and other oxygenated fuels from fossil fuels and renewables have provided sufficient detail on the role of fuel production in the full costs and environmental benefits of alternative fuels that further investigation at this time is not warranted.