NATURAL GAS UTILIZATION

in

petrochemical production
chemical production
energy applications
transportation

This book contains a compilation of papers presented at the Thailand-United States Natural Gas Utilization Symposium.

Bangkok, Thailand
February 7 to 11, 1984

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PREFACE

The presentations that are found in this book represent and describe the most current up-to-date thinking and technology available from American companies that deal with the use of natural gas in transportation, energy applications, chemical and petrochemical production. The papers are of a general nature because they deal with the various forms of processing technology as they apply to natural gas and are not site specific.

A comprehensive list of topics are covered. These include compressed natural gas (CNG), methanol, gasoline and distillate fuels which can be produced from natural gas. Also, cogeneration as well as gas turbines and reciprocating engines that be used for small on-site power plants are addressed. The removal of carbon dioxide from natural gas, the economics and production of fertilizer, ethane/propane cracking technology, polypropylene production, digital simulation in process operations and managing a petrochemical complex are covered too.

The papers in this book were presented at the "The Thailand-United States Natural Gas Utilization" Symposium which was held in February, 1984 in Bangkok, Thailand. This symposium was held because of Thailand's intense and serious interest in developing their nation's natural gas resources. Presentations will also be found in this book that deal with the general energy situation in Thailand and more specifically with natural gas. These papers are presented by the leading authorities of Thailand. Also Union Oil Company and Texas Pacific Oil Company describe their exploration and production activities in the Gulf of Thailand in quite some detail.

This serious interest on the part of Thailand developed because of the large natural gas reserves in the Gulf of Thailand which is benefitting Thailand in many ways. Wholly apart from the obvious savings in foreign exchange, and gaining a reliable domestic reserve of fuel, natural gas is to be utilized as a feedstock in numerous industries, particularly in the production of petrochemicals and fertilizers and, perhaps, as an vehicular fuel in the form of CNG.

The Royal Thai Government is planning and implementing a petrochemical complex to be located adjacent to the Gas Separation Plant in Mab Ta Pud, commonly referred to as the Eastern Seaboard. Ethane and propane from the separation plant will be converted at the olefins plant into 300,000 tonnes of ethylene and 73,000 tonnes of propylene per year.

There are also papers in this book that describe the natural gas situation in the natural gas-rich countries of Brunei, Indonesia, New Zealand and Pakistan.
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Deputy Minister of Industry, Thailand
AMBASSADOR'S OPENING REMARKS

Your Excellency Wang, Dr. Tongchat, honored guests, ladies and gentlemen:

I am honored and pleased to participate at the opening ceremonies of this extremely important Natural Gas Utilization Symposium. The U.S. Government understands the importance of natural gas to Thailand. The further development and use of its own natural gas will not only improve Thailand's balance of payments situation but also accelerate the present efforts towards energy self-sufficiency.

The United States understands and supports the high priority placed by the Royal Thai Government on the use of natural gas in Thailand and the rapid development of the Eastern Seaboard. We note with admiration that plans for the Eastern Seaboard are progressing and that large parts of the basic infrastructure for this vast undertaking are already under design or in place. We also commend the efficient and businesslike way in which several of the major components of the project have moved toward implementation. This progress is, of course, the direct result of highly professional planning and engineering carried out by various agencies of the Royal Thai Government.

As a result, the timing of this symposium could not be better; it should facilitate the weighty decisions that face the Royal Thai Government.

Representatives of U.S. industry will be giving papers on Transportation, Energy Applications and Chemical and Petrochemical Production at this symposium. Much of what is to be presented will be based on the very latest technology available in the world and is designed to expedite and increase the efficiency of the facilities that will be constructed and used in Thailand. American firms, considered by most to be the leaders in this field, look forward to working with Thailand on these projects. The U.S. participants in this symposium are prepared to present a persuasive case for choosing U.S. technology and to answer difficult questions candidly in an open forum.

The U.S. Government supports Thailand in its gas development and use endeavors. Representatives from the U.S. Agency for International Development, The U.S. Trade Development Program, The U.S. Department of Commerce and the U.S. Department of State are present at this symposium.

These agencies may consider financial assistance for projects that are to be developed and more closely defined during this week. I understand that a meeting is already scheduled to take place during the afternoon of February 13 when a list of these high priority projects will be presented to these agencies for serious consideration.

I wish you all the best of success and I am sure that this meeting will be fruitful for all of the attendees.

Thank you.
SPEECH
BY
H.E. MR. WONGSE POLNIKORN
DEPUTY MINISTER OF INDUSTRY
AT
THE OPENING CEREMONY
OF
THE THAILAND - U.S. NATURAL GAS UTILIZATION SYMPOSIUM
FEBRUARY 7, 1984

Your Excellency, Distinguished Guests, Ladies and Gentlemen:

In the unavoidable absence of the Minister of Industry, it is indeed a distinct honour and great privilege for me to preside over the opening ceremony of the Thailand - United States Natural Gas Utilization Symposium today and to have the opportunity to extend to all of you my warmest welcome.

As you may already be aware, Thailand has been fortunate in its recent discovery of large reserves of natural gas, now coming on stream via one of the longest offshore pipeline in the world. This availability of natural gas has greatly facilitated the Government’s ongoing Fifth Five Year Development Plan aimed at improving the people’s standard of living through an integrated industrial and social development programme. As part of our effort to deepen our industrial base, we are encouraging the development of several industrial projects, using natural gas both as a source of energy and as hydrocarbon feedstock for downstream industries. The 350 MMSCFD Gas Separation Plant, presently under construction at Mab Tapud, Rayong Province, the area where the natural gas pipeline comes ashore, commonly referred to as the Eastern Seaboard, is intended to serve among others, the ammonia/urea fertilizer complex and the ethylene-based petrochemical complex. The Government itself will directly invest in the necessary infrastructural supports which include projects for a containerized deep sea-port, provision of water supply and electricity for industrial use, telecommunications services, rail and road network.
In the light of this development, Thailand and the United States have co-sponsored this Symposium with two major objectives. Firstly, to define and discuss technical and economic problems in the development and utilization of natural gas. Secondly, to identify programs, formulate and recommend action plans in the areas of Thailand - United States interest. This is a truly opportune moment for us to take a good look at what lies ahead of us for our mutual benefit.

I am also very much impressed to see that, according to the technical outline of the Symposium, a broad spectrum of subjects, relevant to natural gas utilization and development, will come under your active deliberation. I trust that, with the solid background and fruitful experience of this distinguished representation of experts from various agencies, organizations and companies, this Symposium will prove both fruitful and beneficial, and will serve as the springboard for the strengthening and expansion of our cooperation and close ties in the future.

For the participants who are visiting this country, besides your technical interests, I sincerely hope that you will also have an opportunity to take a glimpse into our genuine Thai ways of life, and above all, have a pleasant stay in Thailand.

Your Excellency, Distinguished Guests, Ladies and Gentlemen, as the auspicious moment has now arrived, I take great pleasure in declaring the Thailand - United States Natural Gas Symposium open.
Thailand's Economic Transformation and Future

Direction of Energy Policy

Presented by

Dr. Phisit Pakkasem
Deputy Secretary - General
National Economic and Social Development Board

at

Thailand - United States Natural Gas Utilization Symposium
Siam Intercontinental Hotel
Bangkok
February 7, 1984
Thailand's Economic Transformation and Future Direction

of Energy Policy

Excellencies Distinguished Participants, Ladies and Gentlemen:

I am delighted to be invited here to speak on Thailand's economic transformation and future direction of our energy policy. This is an immensely broad subject. And because of it, I would like to focus on a few strategic issues which might be of special interest to this high-tech group gathering here today.

On the "Economic Transformation"

I should like to begin my presentation by reporting to you that "Euromoney" magazine of October 1983 ranked Thailand fifth in the category of the world's best economic performance once again in its survey of more than 85 developed and developing countries. This was in terms of the overall economic growth rate, rate of inflation, strength of exchange rate, and balance of payments performance. The Asian Wall Street Journal of August, 1983 also headlined that the Thais have lined up new international financing at the very low interest rate, or at 0.37 of a percentage point over the London interbank offered rate, of which very few countries anywhere in the world today can have access to funds at this rate. This demonstrates the Thai top-notch credit rating, the Wall Street said.
I must say that the Thai Government has demonstrated continuously its commitment to strengthen and diversify our economic base with its own mix of economic policies shaped by our resource rich position, our comparative advantage, social cohesion, and our geoeconomic position in Southeast Asia. But like other countries, Thailand too has some elements of uncertainty. However the following seem to be key growth components leading to high credit rating stand in our sound economic performance during the last two decades.

First, Thailand is a "resource-rich economy" with substantial food surplus which puts Thailand among the world's top 5 countries with "net food exporting position."

Second, The Thai Government tends to follow somewhat conservative fiscal-monetary policies.

Third, Control of major key economic sectors of the economy by "private sector" without too much government interference.

Fourth, Control of economic policy-making by an elite corps of technocrats which provides a degree of built-in stability for economic management and continuity of major economic policies.
However, the next 5 years will be indeed a crucial turning point in our economic history. Thailand's medium-term economic outlook should be viewed as a "transformation stage" from traditional agricultural-rural-resource based to more modern and complex forms of urban-industrial activities which will definitely reinforce the faster rates of urbanization in the 1980s and beyond.

This transformation is taking place very rapidly in the 1980s since our economy now has attained the "capacity to transform itself or the so-called "take off" from traditional to a modern economic system with availability and better use of more efficient technology, capital, and management transfers from abroad. At the same time, the recent discovery and development of national gas in the Gulf of Thailand and oil from the onshore field at Lan Krabue, have dramatically changed our whole resource picture of the country, and opened up entirely new opportunities for creation of viable "basic industries" for Thailand. The current 5th National Development Plan has a very comprehensive industrial restructuring program to make our industries more competitive, outward looking, and less dependent on foreign inputs, and to decentralize our industrial activities away from Bangkok metropolitan area to the new industrial zone at the Eastern Seaboard. The ESB investment program will be about US $ 5 billion at the first stage for the new basic industries and related deep-sea ports. The new basic industries at the Eastern Seaboard
will use our natural gas resources either for energy supply or as feedstock. This ESB is a major industrial breakthrough in Thailand. The top Japan's best-known industrial and international spokesman, Dr. Saburo Okita call the ESB a "new industrial spring-board of Southeast Asia." This new industrial-locational facilities will enable the private and international investors of large industries to invest in this new Seaboard industrial zone of Thailand. Many people thus expect that Thailand, together with other ASEAN countries, will definitely join the ranks of "newly industrializing countries", or the NIC group by the end of this decade.

This NIC group of Southeast Asia are now carving out for themselves an enlarged share of world trade, investment, and total output. This transformation of our economy will change the composition of our production, demand, external trade, employment patterns, and future technology and energy requirements in Thailand. However, our fate in these structural transformation will depend also on world environment trends and a few domestic uncertainties, namely, the world economic recovery, price of oil, and domestic production and additional discovery of gas and crude oil in the immediate future.

A joint NESDB-World Bank simulation of the medium-term outlook of the Thai economy up until 1987 under the above domestic and world environment assumptions shows that Thailand's economy will grow with an average of 6.5% per annum up until 1987 with
The outputs in the non-agriculture, especially industry, energy, construction and service sector expanding at higher rates of 7.7%, 8.3%, 5.5%, and 6.8% respectively. For the energy sector in this medium-run simulation, the imminent economic recovery together with faster rate of urbanization will "push-up" the demand for energy growing more than 6% per annum compared with the current 5th Plan's target of 4.7%.

Meanwhile, the substitution of imported oil by natural gas from the Gulf of Thailand will be slightly lower than the 5th Plan's target of 525 mcfd in 1986. This is, however, compensated by the discovery of Lan Krabue Oil. As a result, our dependence on imported energy will decline from 65% of total energy consumption in 1981 to 45% in 1987. It now seems clear that additions to domestic energy supplies and reserves will make dramatic reduction in energy import-dependence during the rest of 1980s. We are now spending more on energy at an unprecedented rate. Our public investment target for the energy sector during the current 5th Plan is about $7 billion. This covers the EGAT, PTT, PEA, MEA, and NEA development projects to accelerate development of our domestic hydro, lignite, gas and oil resources over the current 5th Plan period. This would definitely reduce our dependence on imported energy sources down to about 33% by 1990. After which period our projections show that imported energy, both oil and
possibly coal, in meeting domestic primary energy demand will begin to climb again to about 44-45 % share by year 2001. This causes some serious concerns among the planners in Thailand.

Some Critical Issues and Future Directions of Energy Policy

Our current energy policy under the 5th Plan period is fundamentally twofold:-

First, to maximize production of domestic energy resources and diversify energy supply structure, in order to reduce Thailand's dependence on imported oil (on supply side)

Second, to restrain the growth of energy demand, particularly petroleum demand, through improved efficiency of energy use, conservation, and pricing policies (on demand management side)

I think the prospects are good for Thailand, which is a net petroleum importer at present, becoming less dependent on petroleum in the future. But both supply and demand management in Thailand's energy sector depend so much on the following policy direction and issues:-
First, on the natural gas, the reliability of reserve estimates is a key issue. This is not only vital to our future import-oil substitution and other transport uses as well as the new industrialization program in the Eastern Seaboard, but also the future of the LNG scheme depends on the gas reserves which need further proving. Some reserve estimates must be treated with some caution. Attempt to quantify the oil and gas potential normally requires a high degree of subjectivity. Another associated issue to any gas development program is the new and additional discoveries. The Government must therefore have some flexibility in order to meet these uncertainties.

Second, the economics of oil and gas exploration and development in Thailand is another issue. We realize that the hydro-carbon exploration and development is of high risk and high gain nature. In addition, this industry is very politically sensitive toward the continuity of the Government policies. However, I feel at the moment that Thailand's petroleum law and tax regimes are quite attractive by international standard. The private industry has already invested more than one billion dollars in this country.
since the promulgation of our Petroleum Act of Thailand. This incentive should therefore be preserved. Many international experts believe that the 1990’s could be a repeat of the 1970’s with international oil price rises again. To offset these possible price rises and to contain our energy import bill, Thailand must do what it can to step up exploration and increase the level of production to ensure that energy production does not decline in the 1990’s. Because of the long lead time oil and gas exploration has to be strong through the middle 1980’s for there to be hope of stabilizing oil imports in the 1990’s.

It is imperative to create right conditions for continued exploration, including newcomer companies. A most important facet of Thailand’s energy policy is the need to maintain an environment which will encourage vigorous exploration for oil and gas. Those companies making discoveries will be assured that there will be reasonable prospects for economic development. When adequate domestic market demands are satisfied, exports will also be seriously considered. Allowing producers
access to both domestic and foreign markets in certain circumstances can transform an otherwise uneconomic scheme into a viable one.

Third, Joint Ventures are another key policy issue. I feel the basic right and terms of joint venture should be determined by Thailand, not by the concessionaire. This view is also shared by 2 recent World Bank's report. This would reduce negotiating time. Recent negotiations between the Texas Pacific Group and the Thai Government have moved one step forward with the suggestion of PTT participation in field development. However, further delay in gas availability and negotiation will probably impose high costs to both parties. We must find ways of speeding up the negotiating process so that gas come on stream sooner because the potential gas use is in excess of supply. In the longer run, step should be taken to gradually develop an independent petroleum capability through joint venture operations.
Fourth, the energy pricing policy is also critical to both supply and demand management of energy sector in Thailand. Our early choice of domestic oil pricing policies in the 1970s was strongly influenced by the desire to maintain high growth rate of GDP. The Governments thus chose to absorb a substantial part of increase in the costs of imported fuel. However, after 1978 domestic energy prices had been drastically adjusted. Thailand now has domestic petroleum prices roughly comparable to those of our neighbours. Our average level of taxation on petroleum products is now comparable to other oil importing countries. We have finally eliminated subsidies to most of our petroleum products.

Regarding oil and gas pricing, regulations should set out a mechanism for pricing domestic crude oil and gas. Present pricing approach based on forecast costs has led to slow and time consuming negotiations. We might consider an alternative by establishing a reference to international parity and possibly reducing the reference price by a small discount for user's incentives.
In sum, the economic transformation in Thailand during the 1980s and 1990s with further intensification of agricultural production, increased industrialization, and higher level of urbanization will definitely increase the average level of per capita consumption of commercial energy. And according to our Energy Master Plan study, Thailand is not and will not be an energy-surplus country. It is necessary for us to diversify our supply sources with an objective to reduce dependence on imported petroleum. This will remain basically unchanged in the future direction of our energy policy. It is essential to devise the best energy supply mix by taking into full consideration the role of our natural gas. Substantial amounts of capital and technology will be required in the gas development and utilization programmes during the next two decades. The public investment programme in gas-related field has already been in the pipeline. We also would like to see more private investment in the downstream projects by creating conditions conducive to smooth financing.

Finally, I must emphasize that continued intensive searching for domestic energy must be further encouraged. We are doing our best to reinforce and rationalize our energy planning and coordination apparatus, to develop political support for energy sector development, and to encourage
private sector participation in the field of energy exploration, development, and conservation programs. We will do our best to attract and retain international investments and technologies required to support our energy policy and development programs.

Thank you.
THAILAND'S INVESTMENT POLICY

A
presentation by

MR. CHIRA PANUPONGSE
Deputy Secretary-General,
Office of the Board of Investment

at the

THAILAND-UNITED STATES NATURAL GAS UTILIZATION SYMPOSIUM

Bangkok
7 February, 1984
Mr. Chairman,

Distinguished Participants:

The key to the successful implementation of the structural adjustments outlined in Thailand's Fifth Five-Year Plan is investment. Primarily private investment, working in a market economy. Our target is a balanced, resource-based growth capitalising on the heavy public infrastructure investment made over the last 25 years.

Productive, profitable investment by the private sector is today providing Thailand with enhanced stability in the economic, financial and social areas. A broader economic base, as a result of diversified investments in the manufacturing sector, is allowing our very open, trade-oriented economy to better survive these turbulent times in the global economy. More rapid rural development, resulting from the rapid growth of our agro-industrial sector, means a more equitable distribution of income.

Through the remainder of this decade larger volumes of private investment will be required, especially to implement the large-scale, capital intensive projects planned for the Eastern Seaboard. The Royal Thai Government, recognising this need, is committed to providing a positive investment environment allowing both Thai and foreign investors maximum flexibility, allowing entrepreneurial dynamism full freedom.

The Government's positive attitude toward private investment is not a transient policy. It is a basic tenet of our national development philosophy. When it was announced 30 years ago Thailand became the first country in this region to publicly recognise private investment as a critical element in the process of national development.
And we have continued to expand and strengthen this commitment to private investment. It is accorded a specific role in the Fifth Plan; we have established the Joint Public-Private Sector Consultative Committee, chaired by the Prime Minister, to provide a permanent dialogue between the two sectors; and the Prime Minister is also Chairman of the Board of Investment, the Thai Government's designated investment promotion agency. In other words the public and private sectors work as partners in the name of national development.

What are the realities of this favourable investment environment the Royal Thai Government is committed to maintaining?

From the investors' point of view we offer three major supports:

- To reduce the risk of investment.
- To reduce the initial investment cost.
- To improve the overall rate of return on investment.

In order to reduce the risks attached to any investment decision we offer standard guarantees against nationalisation and competition from the public sector or monopolisation. We also have signed investment protection agreements with a number of countries.

In order to reduce the initial investment costs and to improve the overall rate of return the Board of Investment can utilise its major discretionary power which is the granting of promotional privileges involving both tax and non-tax incentives. If an investment proposal meets our criteria we will design an incentive package to fit the investor's needs. Depending on the project's characteristics an incentive
package is comprised of some or all of the following benefits:

- Corporate income and dividend tax holidays for between 3 and 8 years. This allows good returns on investment in the early years and a quicker reduction in loan costs.

- Special deductions from taxable income are available for:
  - A proportion of incremental export earnings;
  - Doubled-up expenditures on transport and utilities by companies located in our designated Investment Promotion Zones;
  - Carried forward losses, and
  - Fees relating to goodwill, copyright and other such fees.

- Exemption of import duties and business taxes on:
  - Approved machinery imports, which lower overall investment costs and depreciation charges, and
  - Imported and local raw materials, especially for export-oriented projects, in order to lower the direct costs of production.

- Exemption of duties and business taxes on export sales and reduced business taxes on sales of goods produced in the Investment Promotion Zones designed to increase your competitiveness by world standards.

- Temporary tariff surcharges to prevent unfair competition from imports, especially dumping.

- Permission for:
- foreign ownership of land;
- the entry and employment of foreign experts, skilled workers and their families; and
- the free repatriation of capital and remittance of profits.

In addition to these wide ranging incentives I would like to emphasise that the Office of the Board of Investment is a service-oriented organisation offering a wide range of investment related services to both Thai and foreign investors. I should add that these services are all free of charge. They include:

- Investment information on Thailand available from our headquarters here in Bangkok and through our four overseas offices in Frankfurt, New York, Sydney and Tokyo.

- Investment opportunity surveys and pre-feasibility studies in specific areas as well as research staff to assist potential investors with their additional information requirements.

- Joint-venture partner identification. If you are looking for a Thai partner the BoI can provide you with a short list of qualified and interested potential partners.

- And the services of our "One Stop Services Centre" which is empowered to issue, or obtain from other government agencies all the various permits and licences necessary to establish an operation in Thailand. The Centre operates within strict time limits and guarantees that the applicant will receive all the required permits within 90 days without need of further processing. The Centre
also offers promoted companies such additional services as:

- Providing work permits and visas for foreign experts and technicians;
- Assisting in negotiations with agencies concerning the installation of utilities;
- Advising on the registration of your business;
- Providing general assistance regarding tax payments and refunds; and
- Advising on the repatriation of foreign currency.

I hope by now you will begin to understand that the Royal Thai Government is very serious in its support of private investment but at the same time we also have our own priority target areas. Obviously we are not going to offer a strong package of incentives for those investments in areas where we believe sufficient domestic capacity or competition already exists. There is nothing to stop such investments being made - after all that is what a free market economy is all about - but such investments are unlikely to receive BoI promoted status.

Our priority guidelines have been developed to harmonize with our national development plans and to help investors identify the most profitable investment opportunities, namely those in which Thailand offers an internationally competitive resource base.

The project characteristics which will attract the most generous incentive packages are:

- Those projects which will generate a substantial increase in employment;
- Those projects which are located outside Bangkok;
- Those projects which have energy conservation or substitution for imported fuel
as one element;
- Those projects which are capable of producing foreign exchange earnings or savings; and
- Those projects which are complimentary to the development of basic industries.

On the question of foreign ownership I would say in general that while joint-ventures with Thai majority equity are preferred for those investments in domestic market activities, factors such as size, technology, employment and location may qualify a foreign controlled project for special tax privileges. In export-oriented projects foreign equity may be over 50 per cent and up to 100 per cent if all production is exported. These equity guidelines refer of course to projects requesting BoI promotional privileges. For those investors not looking for promoted status Thailand maintains an open-door policy toward foreign investment by which we treat Thai and foreign investors on an equal basis.

Ladies and gentlemen, the Kingdom of Thailand recognises our need for foreign investment as a catalyst in the process of national development. We need your technology, your management expertise and your international marketing skills as much as we need your capital.

We recognise a mutuality of interests and the need for a fair distribution of benefits. We are prepared to be flexible. Sometimes we bargain hard for what we believe represents this equitable distribution of benefits. But once we have struck an agreement we keep to it.

If you are to believe all that I have said this morning then I hope Thailand sounds like an absolutely marvellous place in which to invest. But it is possible that I might be accused of bias. After all it is my job to persuade people to invest in
my country. I decided therefore to conclude my presentation by calling upon a more objective authority to give their view of Thailand.

In October, 1983 the prestigious Institute for Economic Research based in Munich, West Germany released some interesting information which its experts had compiled for a major international conference on the growth markets of East and Southeast Asia. The Institute ranked the eight selected countries in terms of business climate, investment climate and expected annual economic growth. In each of these categories Thailand was ranked first, or equal first, and above all other ASEAN countries.

I hope during the course of this symposium you will come to confirm these objective evaluations in your own minds and report back to your head offices accordingly.

Thank you.
ENERGY RESOURCES AND RESERVES

A

Presentation by

Sivavong Changkasiri

Director - General

Department of Mineral Resources

at the

THAILAND-UNITED STATES NATURAL GAS UTILIZATION

SYMPOSIUM

Bangkok

February 7, 1984
Mr. Chairman, Distinguished Participants,

Ladies and Gentlemen:

According to a recent UN report, Thailand ranks sixth out of 94 developing countries in the amount of oil imported. We are, at present, importing approximately 200,000 Barrels/day of oil and refined products to supply our domestic needs.

Energy is one of the most important factors in sustaining Thailand's economic growth. However, the high cost of imported energy has put a large burden on our foreign exchange reserves. Furthermore, too much reliance on foreign oil puts our social and economic development plans at risk with respect to pricing and political uncertainties in the producer countries.

The Royal Thai government realizes that one of the solutions would be to put more emphasis on developing the country's own abundant energy resources such as oil and gas, coal, oil shale, geothermal energy and radioactive minerals.

In this context, I am happy to say that Thailand has leaped forward rapidly during the past decade in utilizing her own energy
resources to help sustain growth.

We are not fully self-reliant in energy yet. But gradually, we are becoming an energy-producing country thereby reducing the amount of energy imported.

At this stage, a lot of exploration, research and development tasks are underway in order to find more energy resources in our own country. May I begin by reviewing each category of our energy resources and reserve figures starting with petroleum resources.

Petroleum was discovered many decades ago in Thailand. However, in those days due to the lack of incentives and technical know-how, the exploration activities were very limited. Only one small oil field was discovered by the Defense Energy Dept. in the Fang district in the Northern province of Chiang-Mai. Although over 30 years old the Fang field is still producing oil today at a rate of approximately 600 B/D.

Exploration activities in Thailand started to intensify in the 1970's after the government promulgated the Petroleum Act and the Petroleum Income Tax Act designed to attract foreign capital and technology for exploration ventures in our country.
Since then, more than 164 exploration wells have been drilled in both onshore and offshore areas by various international oil companies. Some have met with success while others were not so lucky, and some are just beginning to enter the venture.

In regard to petroleum resources and reserves in Thailand:

There are at present 13 commercial gas fields of which 12 are in the Gulf of Thailand. Ten of these fields are in Union's concession blocks. Two of these fields are being developed. The Erawan field started production in September, 1981 and is currently producing about 153 MMSCF/D of natural gas plus about 7000 B/D of condensate. The Baanpot field started producing in Oct. '83 and is currently producing about 15 MMCF/D of natural gas plus about 1000 B/D of condensate.

The combined proved reserves of all offshore fields in the Gulf of Thailand now stand at about 5.94 trillion SCF of natural gas and about 119.5 million barrels of condensate.

With respect to the offshore activities in the Andaman Sea, 11 exploration wells have been drilled, but no commercial petroleum deposits have yet been found. The Thai government is now in the process of granting 2 concession blocks one to Placid Oil and another to MAPCO 2 for
petroleum exploration in those areas.

In the central part of the country, one commercial oil field was found in late 1981 in the Lan Krabua sub-district in Kamphangphet province. The field which was later to become known as the Sirikit field, officially went into production in January 1983 and is now producing about 10500 B/D of crude oil plus about 9.6 MMSCF/D of associated natural gas. The recoverable reserves in this Thai Shell operated field are estimated at 30 MMSTB.

Besides the Sirikit field, Thai Shell is also testing the commercial feasibility of their recent oil finds in the Nong Makham structure in Khamphangphet province, the Nongtum structure in Phitsanulok province, and the Mar Nam Nan structure in Uttra-radit province.

In addition, MGF Oil, another concessionaire in the Central Plain of Thailand, will commence its seismic exploration this year.

I would like to add that the government is in the process of granting more concession blocks in this Central Plain area to South-West Consolidated of Great Britain.
In 1981 Esso Exploration and Production Khorat Inc. discovered a potential gas field in one of its concession blocks located in the Northeastern province of Khon-Kaen. The so-called Nam-Phong structure is now being appraised and tested by further drilling to evaluate its potential. The possible reserves of this Nam-Phong field are initially estimated at 70-90 billion SCF (based on one well "Nam-Phong 1"; estimated by Esso).

Besides Esso, other concessionaires in the Northeast part of the country who are undertaking exploration work are Phillips Petroleum Company and Terra Marine International.

Overall, today the combined crude oil and condensate production of the country is about 18,500 B/D, and the combined natural gas production is about 184.6 MMSCF/D. And if the natural gas production is compared based on its heat-equivalence to oil, the combined domestic petroleum production would be about 49,900 B/D.

The second category of energy resources is coal. Coal production in Thailand began in the Electricity Generating Authority of Thailand mine at Amphur Mae Moh of Lampang Province which in 1955 produced 40,651 tonnes of coal. Since then coal production has increased substantially; the latest figures indicate that in 1982 the country's total coal production was about 2 million tonnes of which 1.3 million tonnes came from EGAT's Mae Moh mine.

Coal deposits have been found throughout Thailand, mostly in the Northern part. High Coal potential areas include, Lampang, Chiang Mai, Pa yao, Tak, Krabi, Petchaburi, and Loei Provinces, with total inferred reserve of 1,485.3 million tonnes. Parts of these coal deposits are being mined by EGAT, NEA (National Energy Administration).
and five other private mining companies. The total proved reserves within these mining areas is about 678.05 million tonnes.

Oil shale is the 3rd category of energy resources I would like to address today. Oil Shale deposits have been discovered in several locations throughout the country. However, the Mae Sod deposit in Tak Province which covers an area of approximately 54 km² has been studied in detail and found to be economically attractive. The oil shale reserves of this Mae Sod deposit are estimated at 18,600 million tonnes which is equivalent to about 6,000 million barrels of crude oil.

In 1983, the Japan International Cooperation Agency (JICA) assisted the Department of Mineral Resources in carrying out a feasibility study on an Integrated Power and Cement Plant using Oil Shale at Amphur Mae Sod in Tak Province.

The study concluded that a project capable of producing 808,500 tonnes of cement per year and 12.5 MW of electricity from oil shale is feasible.

Geothermal energy is another energy resource which lately has received considerable attention, 64 hot springs have been found throughout Thailand, 41 of which are in the northern region. About 5 hot springs, 4 in Chiang Mai and 1 in Chiang Rai, whose reservoir temperatures range between 175-200°C have been considered as technically attractive. One geothermal source found at Pong Hom of Amphur Sankampang in Chiang Mai Province was estimated to be capable of supplying power to a 20 MW power plant.
Another geothermal source at Amphur Fang of Chiang Mai Province, which is currently under study, was estimated to be capable of generating 7 MW of electricity.

The final category of energy resources in my discussion today concerns radioactive minerals.

Potential resources of radioactive minerals in Thailand can be classified into two major geologic types.

First, Uranium and Thorium in monazite sands in tin-placer deposits. Substantial low-grade deposits of Thorium and Uranium as well as rare-earth elements are present in monazite, found mainly in Phuket, Phung-nga, and Ranong areas.

Second, Uranium in sandstone deposits on the Khorat Plateau. These appear to be the principal domestic resources of Uranium, found in the vicinity of Phu-Wiang, Khonkaen. Three ore bodies have been recognized, covering areas of about 975 m², 350 m² and 20,000 m², ranging in thickness from 0.3-1.2 m, with grades of 0.1-0.278% U₃O₈ (Uranium Oxide)

Distinguished participants, from my brief survey of Thailand's energy resources and reserves it should be apparent that we are not about to join the OPEC cartel. Thailand is unlikely ever to become totally self-sufficient in petroleum production. What we are committed to is a very rapid development of all our domestic energy resources be they oil, gas, coal or hydro in order to reduce our dependence upon imported energy supplies and to increase our own sense of self-reliance. I hope you will bear these objectives in mind during this course of this symposium.

Thank you.
## PROVED RESERVES OF GAS FIELDS IN THE GULF OF THAILAND

<table>
<thead>
<tr>
<th>FIELD</th>
<th>BLOCK</th>
<th>OPERATOR</th>
<th>GAS (BCF)</th>
<th>CONDENSATE MMBBL</th>
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<tbody>
<tr>
<td>KAPHONG</td>
<td>10</td>
<td>UNION</td>
<td>376</td>
<td>6.70</td>
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<tr>
<td>PLATONG</td>
<td>10,11</td>
<td>&quot;</td>
<td>376</td>
<td>12.72</td>
</tr>
<tr>
<td>PLADANG</td>
<td>11</td>
<td>&quot;</td>
<td>376</td>
<td>7.56</td>
</tr>
<tr>
<td>PAKARANG</td>
<td>11</td>
<td>&quot;</td>
<td>282</td>
<td>5.66</td>
</tr>
<tr>
<td>TRAT</td>
<td>17</td>
<td>&quot;</td>
<td>282</td>
<td>5.45</td>
</tr>
<tr>
<td>SATUN</td>
<td>11,12</td>
<td>&quot;</td>
<td>658</td>
<td>22.38</td>
</tr>
<tr>
<td>ERAWAN</td>
<td>12,13</td>
<td>&quot;</td>
<td>628</td>
<td>21.60</td>
</tr>
<tr>
<td>BAANPOT</td>
<td>13</td>
<td>&quot;</td>
<td>470</td>
<td>8.31</td>
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<td>FUNAN</td>
<td>13</td>
<td>&quot;</td>
<td>282</td>
<td>5.45</td>
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<tr>
<td>JAKRAWAN</td>
<td>12,13</td>
<td>&quot;</td>
<td>282</td>
<td>2.70</td>
</tr>
<tr>
<td>B</td>
<td>15,16</td>
<td>TEXAS PACIFIC</td>
<td>1,798.6</td>
<td>10.60</td>
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<tr>
<td>E</td>
<td>16,17</td>
<td>&quot;</td>
<td>124.6</td>
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<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td><strong>5,935.2</strong></td>
<td><strong>119.53</strong></td>
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**REMARK:** COMPILED FROM UNION, TEXAS PACIFIC AND DeGOLYER AND MacNAUGHTON REPORTS.
### PRODUCTION FROM ERAWAN

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<tr>
<th>YEAR</th>
<th>GAS</th>
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<tr>
<td></td>
<td>PRODUCED</td>
<td>AVG. PROD.</td>
<td>PRODUCED</td>
<td>AVG. PROD.</td>
</tr>
<tr>
<td></td>
<td>(MMCF)</td>
<td>(MMCF/D)</td>
<td>(BBL)</td>
<td>(BBL/D)</td>
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<tr>
<td>AUG.-DEC. 81</td>
<td>10,820</td>
<td>70</td>
<td>469,759</td>
<td>3,072</td>
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<td>1982</td>
<td>47,147</td>
<td>129</td>
<td>2,025,254</td>
<td>5,549</td>
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<tr>
<td>1983</td>
<td>53,830</td>
<td>147</td>
<td>2,205,935</td>
<td>6,044</td>
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<tr>
<td>TOTAL</td>
<td>111,797</td>
<td></td>
<td>4,701,951</td>
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</table>
### Production from Sirikit

<table>
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<th></th>
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</thead>
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<td>Jan. 83</td>
<td>104,700</td>
<td>3,374</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Feb. 83</td>
<td>116,636</td>
<td>4,237</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Mar. 83</td>
<td>132,057</td>
<td>4,259</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Apr. 83</td>
<td>123,647</td>
<td>4,122</td>
<td>123</td>
<td>4.1</td>
</tr>
<tr>
<td>May 83</td>
<td>125,477</td>
<td>4,048</td>
<td>124</td>
<td>4.0</td>
</tr>
<tr>
<td>June 83</td>
<td>108,772</td>
<td>3,626</td>
<td>132</td>
<td>4.4</td>
</tr>
<tr>
<td>July 83</td>
<td>165,137</td>
<td>5,327</td>
<td>169</td>
<td>5.5</td>
</tr>
<tr>
<td>Aug. 83</td>
<td>214,562</td>
<td>6,921</td>
<td>209</td>
<td>6.7</td>
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<tr>
<td>Sept. 83</td>
<td>237,856</td>
<td>7,795</td>
<td>224</td>
<td>7.5</td>
</tr>
<tr>
<td>Oct. 83</td>
<td>276,346</td>
<td>8,914</td>
<td>263</td>
<td>8.5</td>
</tr>
<tr>
<td>Nov. 83</td>
<td>286,874</td>
<td>9,563</td>
<td>289</td>
<td>9.6</td>
</tr>
<tr>
<td>Dec. 83</td>
<td>328,369</td>
<td>10,593</td>
<td>335</td>
<td>11.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2,218,122</strong></td>
<td></td>
<td><strong>1,888</strong></td>
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</table>
## Potential Coal Resources and Reserves

<table>
<thead>
<tr>
<th>LOCATION DISTRICT, PROVINCE</th>
<th>INFERRED RESERVES (million tonne)</th>
<th>MINING OPERATOR</th>
<th>PROVED RESERVES (million tonne)</th>
<th>ASTM RANK</th>
<th>STARTED MINING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mae Moh, Lampang</td>
<td>1,317.4</td>
<td>EGAT at Mae Moh</td>
<td>661.0</td>
<td>Lignite B-Subbituminous C</td>
<td>1955</td>
</tr>
<tr>
<td>Ngao, Lampang</td>
<td>33.0</td>
<td>Phrae Lignite at Mae Tip</td>
<td>0.79</td>
<td>Subbituminous A-High Volatile C</td>
<td>1976</td>
</tr>
<tr>
<td>Wang Nua, Lampang</td>
<td>25.9</td>
<td>-</td>
<td>-</td>
<td>Not Available</td>
<td>-</td>
</tr>
<tr>
<td>Chae Hon, Lampang</td>
<td>14.1</td>
<td>-</td>
<td>-</td>
<td>Not Available</td>
<td>-</td>
</tr>
<tr>
<td>Mae Tha, Lampang</td>
<td>4.8</td>
<td>-</td>
<td>-</td>
<td>Not Available</td>
<td>-</td>
</tr>
<tr>
<td>Li, Lampang</td>
<td>48.0</td>
<td>NEA at Dong Dam</td>
<td>6.0</td>
<td>Subbituminous A-High Volatile C</td>
<td>1969</td>
</tr>
<tr>
<td></td>
<td></td>
<td>World fuel at Li</td>
<td>2.0</td>
<td>Subbituminous C</td>
<td>1979</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Dharumaprida at Na Sai</td>
<td>1.1</td>
<td>Lignite A-Lignite</td>
<td>1983</td>
</tr>
<tr>
<td>Chiang Maun, Pa-Yao</td>
<td>1.5</td>
<td>-</td>
<td>-</td>
<td>Not Available</td>
<td>-</td>
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<tr>
<td>Mae Ramat, Tak</td>
<td>3.5</td>
<td>Thai Lignite at Mae Tun</td>
<td>1.0</td>
<td>High Volatile C-A Bituminous</td>
<td>1980</td>
</tr>
<tr>
<td>Chiang Dao, Chiang Mai</td>
<td>5.0</td>
<td>-</td>
<td>-</td>
<td>Not Available</td>
<td>-</td>
</tr>
<tr>
<td>Hot, Chiang Mai</td>
<td>3.8</td>
<td>-</td>
<td>-</td>
<td>Not Available</td>
<td>-</td>
</tr>
<tr>
<td>LOCATION</td>
<td>INFERRED RESERVES (million tonne)</td>
<td>MINING OPERATOR</td>
<td>PROVED RESERVES (million tonne)</td>
<td>ASTM RANK</td>
<td>STARTED MINING</td>
</tr>
<tr>
<td>----------</td>
<td>----------------------------------</td>
<td>-----------------</td>
<td>--------------------------------</td>
<td>-----------</td>
<td>---------------</td>
</tr>
<tr>
<td>Nong Ya Plong, Petchaburi</td>
<td>1.3</td>
<td>-</td>
<td>-</td>
<td>NA</td>
<td>-</td>
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<tr>
<td>Klong Thom, Krabi</td>
<td>26.0</td>
<td>EGAT at Klong Kha-nan</td>
<td>5.16</td>
<td>Lignite B-Lignite A</td>
<td>1963</td>
</tr>
<tr>
<td>Na Duang, Loei</td>
<td>1.0</td>
<td>Siam Graphite at Na Duang</td>
<td>1.0</td>
<td>Anthracite</td>
<td>1982</td>
</tr>
<tr>
<td>TOTAL</td>
<td>1,485.3</td>
<td>TOTAL</td>
<td>678.05</td>
<td></td>
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</tr>
</tbody>
</table>

TOTAL: 678.05
THAILAND'S ENERGY SUPPLY AND DEMAND PATTERN

A

Presentation by

Dr. Tongchat Hongladaromp

Governor,

Petroleum Authority of Thailand

at the

THAILAND-UNITED STATES NATURAL GAS UTILIZATION

SYMPOSIUM

Bangkok

February 7, 1984
Mr. Chairman,

Distinguished Participants:

On behalf of the Petroleum Authority of Thailand, I wish to extend a warm welcome to you all. It is a pleasure and privilege to be here this morning at the introductory session of the Symposium.

Without doubt, your presence here today makes this the most distinguished gathering of technical expertise in the petroleum and energy development ever to be assembled in Thailand.

You should remember the Petroleum Authority of Thailand is a very young organisation. This year we celebrate our fifth birthday. On the other hand the United States has accumulated almost 100 years of world leadership in the petroleum energy sector. Many of you here today represent a state-of-the art reflection of this leadership.

It is our job here in Thailand to compress your century of learning and experience into perhaps a decade. As the country's national oil company, the Petroleum Authority of Thailand is in the vanguard of this drive toward managerial and technical self-sufficiency...
in the rapid development of Thailand's domestic petroleum resources.

This is why, as the Authority's Governor, I am particularly pleased to welcome you and deeply appreciative of the support extended by the Embassy of the United States here in Bangkok.

Already, this morning, you have received concise briefings on the state of Thailand's economy, the structural transformation process through which we are currently moving, our national energy and investment policies and our basic energy resource position. These briefings were designed to provide you with a framework within which more specific topics could be addressed during the course of this symposium.

It is my pleasant duty to complete this framework by describing Thailand's present and projected energy supply and demand patterns and by outlining the massive petroleum-related development plans for the remainder of this decade.

What I will be describing amounts to the largest integrated investment plan this country has ever undertaken. To date some 2.5 billion US. dollars has already been invested in the exploration and development of Thailand's recently discovered petroleum resources. By 1990 close to another 5 billion US dollars will-have been invested in projects which
are already committed and this does not include additional developments resulting from intensive, on-going exploration activities.

Obviously, the success of these plans will be vital to Thailand’s overall drive toward industrialisation.

To understand where we are going you need to know where we are today. What then is Thailand’s current energy profile?

By the end of 1983 Thailand was consuming the equivalent of over 300,000 barrels of crude oil each day. Of this amount 62 percent was supplied by oil, 8 percent by gas, 6 percent by hydro, 3 percent by lignite and 21 percent from other sources such as charcoal, and solar.

On the demand side, industry was accounting for 25 percent, the same as for transport and the combined commercial and residential sectors. Agriculture, still the largest sector of the Thai economy, accounted for only 7 percent of total energy demand.

I should point out here that 1983 represented only our second full year of natural gas production and the first year of significant crude oil production. If you looked at the energy supply picture for
1980 you would see that crude oil, all of it imported, then accounted for over 70 percent of total energy supply.

If we project our energy demand pattern through to 1990 you can see that we expect this trend of a reducing dependence upon oil, especially imported oil, to continue. By then oil will account for only 45 percent of total energy supply with gas rising sharply to 22 percent followed by hydro and lignite each with 9 percent and with the remaining 15 percent coming from other sources.

So much for the overall energy outlook. Let us now take a closer look at the petroleum sector.

The pattern of demand for petroleum products in Thailand is rather unusual due to the very high demand for middle distillates, speed diesel for our trucking fleets. Thailand exports more than 10 million tonnes of agriculture products each year and virtually all of this is trucked to our ports. As a result we have the largest trucking fleet in Southeast Asia and a difficult product demand structure. This is why we are extremely interested in exploring the possibilities of Compressed Natural Gas for use in diesel engines, a subject we shall be learning about later on in this Symposium.
This changing pattern of demand through 1990 means that LPG will jump from 6 percent of total product demand in 1983 to 11 percent. Middle Distillates will increase from 49 percent to 58 percent while fuel oil will drop from 28 percent to 15 percent as more natural gas becomes available for power generation purposes.

We are taking advantage of this situation by expanding and converting all three of the country's oil refineries so that they produce less of the fuel oil we won't be needing and more of the Middle Distillates we will be needing. These refinery expansions will also end Thailand's deficit refinery capacity situation and by 1990 we expect to be self-sufficient in this respect.

What are our sources of petroleum supply?

In 1983 the total consumption of petroleum products amounted to 210,000 barrels per day of which LPG accounted for 13,000 Motor Gasoline for 36,000 Middle Distillates 103,000 and fuel oil 58,000.

By 1990 we expect to be consuming 243,000 barrels per day with LPG accounting for 27,000 Motor Gasoline 39,000, Middle Distillates 141,000 and fuel oil 36,000
In 1983 we imported an average of 199,000 barrels per day of crude and refined products, and produced domestically 12,000 barrels per day of crude and condensate and 147 million cubic feet per day of natural gas. That’s a very heavy dependence upon imports and a very large foreign exchange bill.
But by 1990 we expect to see a dramatic improvement. Oil imports are actually expected to decline slightly to 189,000 barrels per day in spite of the much higher overall demand for energy, while indigenous crude and condensate production will climb to 55,000 barrels per day and natural gas production will have jumped to 700 million cubic feet per day. Thus our dependence upon imported oil will drop sharply from 83 percent of total petroleum supplies in 1983 to 52 percent in 1990 while domestic production of oil and gas will increase from 6 and 11 percent respectively to 15 and 33 percent.

These figures are at the heart of our ambitious development plans for the remainder of this decade. Our first objective is to reduce our staggering oil bill and to protect the country as far as possible from the volatile global oil market. This objective we are already achieving; even after only 3 years of domestic production. By 1990 savings in imported energy costs should be in the order of one billion dollars a year. And these are the most conservative figures, based upon production levels which we are absolutely certain will be met.

Our second objective of course is to establish a basic petrochemical industry using indigenous feedstock, but more about that in a few minutes.
First allow me to show you where these new supplies of domestically produced oil and gas are coming from.

In 1983 domestic oil production averaged 12,000 barrels per day, half from offshore condensate and half from Sirikit Field crude. Please remember these are average figures. In fact by December of last year the Sirikit Field was already producing over 10,000 barrels per day.

But of course our domestic crude oil resources are still small in comparison with our natural gas resources, even although we have had more than our fair share of setbacks in this later sector. In 1983 we averaged 147 million cubic feet per day from the offshore Erawan Field under our first gas supply contract with Union Oil.

Again production was on a rising trend toward the end of the year. By 1985 production will be up to 450 million cubic feet as Union Oil's second supply contract comes on-stream.

By 1990 Thailand will be producing a minimum of 700 million cubic feet per day with the incremental supplies coming from the Texas Pacific Fields.
The demand pattern for this gas is as follows: All of the 147 million cubic feet per day produced in 1983 went to fuel electricity generating plants. By 1985 these plants will be consuming 340 million cubic feet with industrial users taking another 40 million cubic feet and LPG production another 70 million cubic feet. By 1990 electricity production will be taking 480 million cubic feet, industrial consumption and LPG production 40 and 70 million cubic feet, respectively and feedstock 110 million.

There has been some uncertainty and even more public discussion surrounding the level of our natural gas reserves and also, of course, our marathon negotiations with Texas Pacific. On the first point I would like to stress that our proven reserves are more than sufficient to meet all currently projected requirements. Today we know we will have enough gas for the power stations, the separation plant, the petrochemical complex and the fertilizer plant. What we are not sure about is the availability of additional supplies either for export or for further utilization in Thailand.

On the second point - our negotiations with Texas Pacific - I would like to stress that the Royal Thai Government is absolutely committed to achieving a rapid and equitable solution to these negotiations
which we all agree have gone on for far too long. I personally believe that Texas Pacific also shares this commitment and I confidently expect substantial progress in the coming months.
With the Royal Thai Government firmly committed to the rapid development of the substantial, proven reserves of natural gas and with the international investment needed to exploit these reserves lined up, we launched our natural gas development program.

If we look first at the production and pipeline network elements of this program it will simplify things somewhat.

Our first production area was to be Union Oil's Erawan Field deep in the Gulf of Thailand. But of course our load center is up here in Bangkok. The answer was the world's longest submarine gas transmission pipeline - 425 kilometres in length and 34 inches in diameter - extending from Union Oil's production platform in Block 12 to the on-shore Dew Point Control Unit. His Excellency the Prime Minister presided over the commissioning of this pipeline on September 12th, 1981.

The gas coming onshore entered another 160 kilometre pipeline serving two power plants belonging to the Electricity Generating Authority of Thailand - the Bangkok South and Bangpakong plants.
At the same time the main pipeline was being commissioned, construction started on another 178-kilometre onshore pipeline to supply gas to two cement plants belonging to the Siam Cement Company, Southeast Asia's largest manufacturer of construction materials. The pipeline was commissioned late last year and will eventually carry 0 million cubic feet of gas per day to the cement plants and other industrial users.

What was needed then was more gas and Union Oil was ready to go with five gas fields in Blocks 10 to 13 with proven and provable reserves of 4.85 trillion cubic feet. A second gas sales contract was signed in May, 1982 calling for production of 300 million cubic feet per day with an option for an additional 100 million cubic feet if technically feasible. The first gas from this Union Oil Contract II will come on-stream in March of next year using a new 43 kilometre, 24 inch diameter submarine pipeline which is presently under construction for the Petroleum Authority of Thailand. This pipeline ties-in the five new fields with the main transmission pipeline.
The presently envisaged gas production and transmission network has two other main components planned for the near future. As soon as we reach a gas supply agreement with Texas Pacific for gas from its "B" Structure we will start construction of a 170 kilometre pipeline to tie the Texas Pacific field into the main transmission pipeline. The development of the field and the pipeline should be completed within five years.

The other major pipeline project would link the main pipeline to the south coast of Thailand to provide gas for EGAT's Khanom power station. This project is currently under evaluation.

With a substantial production and pipeline network in place or under construction the question of maximising the value of the country's gas reserves becomes the next challenge. Our response has been extremely cautious in the planning stages but hold in implementation. By their very nature, gas utilization projects tend to be large and expensive. We cannot afford to make any mistakes.

The first gas consumers were the electric power utility and industry. But the gas from the Gulf is a rich gas with high concentration of gas liquids
and the country's demand for LPG was rising rapidly.

A gas separation plant made good sense and in February, 1981, seven months before the commissioning of the main pipeline, the Council of Ministers authorised the Petroleum Authority of Thailand to proceed with the project.

In rapid succession approval for the gas separation plant was followed by the green light for a national network of LPG distribution centres and two industries which will use products from the separation plant as feedstock; the petrochemical complex and the fertiliser complex.

Let us look at these key gas utilisation projects in more detail.

When completed in January of next year the gas separation plant will be capable of processing 350 million cubic feet of gas per day. The project includes product pipelines, a marine terminal and LPG storage facilities.

The plant will produce 460,000 tons per year of LPG and propane, 320,000 tons of ethane and 66,000 tons per year of natural gasoline. The total project cost will be 320 million US. dollars. The construction for the plant, pipeline and marine terminal has progressed according to schedule.

To handle the LPG produced by the gas separation plant and distribute /it......
its benefits more widely throughout the country we will shortly start
construction of a network of six regional LPG distribution centres each with
1,000 - 2,000 tons storage tanks and a cylinder filling plant. In this way we
aim to provide a clean, reasonably priced fuel for domestic consumption across
the country.

With the gas separation plant in place and on-stream next year the
six will be set for the establishment of a world-scale basic petrochemical
complex. We have devised what we consider a creative ownership structure for
this complex providing a stable mix of public and private investment. Utilising
ethane and propane from the separation plant as primary feedstock, the up-stream
olefins plant will consist of an ethane cracker with an output of 300,000 metric
tons, a propane dehydrogenator producing 73,000 metric tons of propylene and
a central utilities plant to service both upstream and downstream facilities.
The upstream unit will be jointly owned by the Petroleum Authority of Thailand
and the private sector investors involved in the downstream complex. A joint-
venture agreement to this effect was signed recently.

The downstream units will be comprised of a 100,000 metric tons per
/year.......
year low density polyethylene unit, a 110,000 ton high density polyethylene unit
a 70,000 ton polypropylene unit, an 80,000 ton vinyl chloride monomer unit
and a 50,000 tons per year ethyl glycol unit. All downstream units will be owned
and operated by the private sector.

The whole complex has a projected total cost of 270 million US dollars.

I expect the whole complex to be on-stream in 1988.

The founding of the National Fertilizer Corporation in late 1982
was another example of a complimentary mixed, public-private equity structure.
The NFC is owned 45 by public sector agencies and 55 per cent by private sector
interests involved in the fertiliser business.
Fertilizer consumption in Thailand is very low, in fact one of the lowest rates in Asia, which is surprising when you remember that Thailand is the only net food exporter in Asia and only one of six such countries in the world. Moreover practically all fertilizer nutrients consumed in Thailand are imported, either as finished or intermediate products which are then blended or compounded in local plants.

It should be obvious then why the Government attaches such great importance to the fertilizer complex even at a projected cost of 560 million dollars. When completed in 1988 the complex will produce 900 tons per day of ammonia, 1,000 tons per day of urea, 2,110 tons of sulphuric acid, 720 tons of phosphoric acid and 2,800 tons per day of MAP/DAP/NPK.

Distinguished participants, I fear that I may have overloaded your capacity to absorb facts and figures. We felt it a necessary task if you were to have a satisfactory information framework for the rest of this symposium.

What I have been describing to you adds up to the major components of our integrated Eastern Seaboard Development Program. More than any other development project in Thailand's history this program promises
to change the face of a whole region of the country and provide the
foundations for a whole new phase in Thailand's industrialisation.

The governing body of this Eastern Seaboard Development
Program is chaired by His Excellency the Prime Minister who is personally
committed to maintaining the program's momentum. All basic industries
are being integrated as is the development of infrastructures and utilities.

The program is ambitious in its scope. It is also entirely
feasible in the view of the best international experts available. As
a nation we are committed to its successful implementation.

The Eastern Seaboard Development Zone will provide the new
industrial spring-board for Southeast Asia

It will also generate greatly increased prosperity for the Thai
people, an objective I would ask you to share during this symposium.

Thank you.
THE UNION OIL COMPANY OF THAILAND'S OPERATIONS IN THE GULF OF THAILAND

by

Dr. Harold M. Lian
President
Union Oil Company of Thailand

and

Martin F. Miller
Vice President - Operations
Union Oil Company of Thailand

Thailand - United States Natural Gas Symposium
February 7, 1984
Bangkok
Your Excellencies, ladies and gentlemen:

Thank you for the invitation to participate in this symposium. We welcome the opportunity to describe our activities. Union Oil Company is proud of its role in helping Thailand develop its energy resources. We have participated in the beginning of a new industry in Thailand - an industry that is already bringing many benefits to the Kingdom, and which will bring many more in the years ahead.

Pioneering efforts in any endeavor are likely to bring many surprises and challenges. These have been present in the Gulf of Thailand, in great abundance.

The South East Asia Petroleum Exploration Co., Ltd. is a co-venturer in Erawan and Baanpot fields. Mitsui Oil Exploration Co., Ltd. is a co-venturer in the Platong and Satun fields. Interests in the Second Sales Contract are in the process of being cross-assigned so each of the three concessionaires will have a constant interest throughout the contract area. During this talk I may say "we" or "Union" solely for brevity, but Seapec and/or Moeco are always included.

I will make some general remarks about the geologic environment, and the background of our current activities. Mr. Miller will then describe the development of the four gas fields.

This is not the forum for a rigorous geologic treatment of a very complex geologic province. The geologists present will recognize that the comments are very generalized.

However, a brief look at the geologic history of the Gulf of Thailand is instructive. The factors that shaped the basin and determined the type of sedimentation in the basin are responsible for the present-day geology. The present-day geology controls the search for oil and gas.
This slide shows the location of sedimentary basins in Thailand. I will talk only about the Pattani Basin—sometimes called the Thai Basin. The Pattani Basin occupies only a small portion of the Gulf of Thailand. It is an elongate, north-south trending feature, approximately 400 kilometers long and 125 kilometers wide. The Erawan field is located in the southern part of the Basin.

The area now occupied by the Gulf of Thailand was a part of the Asian landmass until very recently in geologic time.

Mountain building occurred on the east and west sides of the Pattani Basin over 70 million years ago.

The intervening area, in the central portion of what is now the Gulf of Thailand, was a lowland then and has remained a lowland ever since.

About 40-50 million years ago the area of the Pattani Basin started to slowly subside. As it did, streams flowing off the surrounding mountains brought the products of erosion into the lowlands, where they accumulated as alluvial flood plains, river delta systems, sand dunes, lake beds, etc. From time to time parts of the area were covered by swamps. This continued for many millions of years, with the sediments accumulating in the slowly subsiding basin in a shifting pattern of sedimentation. Rivers meandered over the
landscape, changing course from time to time, swamps were filled with vegetation and buried under younger sedimentary deposits. Lakes came and went. This pattern continued while the Pattani Basin subsided deeper and deeper into the earth's crust, to depths of 9-10 kilometers. The surface was above sea level most of the time, for sedimentation kept pace with subsidence.

SLIDE 2 ISOPACH MAP

This map shows the total thickness of the Tertiary sediments that accumulated in the Pattani Basin. These are the sediments in which the gas is found. The darker the color, the thicker is the sedimentary column. The uncolored areas have less than one kilometer of Tertiary sediments. The darkest color represents 9 kilometers of sediments. The location of Erawan field is shown.

During the latter part of the structural evolution of the basin this area was subjected to crustal movements which produced a regional uplift, and a very large number of north-south trending faults. Natural gas migrated about in response to these crustal movements and accumulated in some of the porous sandstone beds, trapped by the lenticularity of individual beds, and by faults.

SLIDE 3 WEST-EAST SEISMIC LINE ACROSS PATTANI BASIN

This regional west-east seismic line shows the configuration of the Pattani Basin. The horizontal distance is about 70 kilometers. The deepest part of the basin here is about 8 kilometers below sea level. The locations of Erawan, Satun and Trat gas fields are projected into this section.
The yellow, green and blue layers represent the Tertiary sediments that fill the Basin. Only a few of the faults are shown on this greatly reduced section.

The geologic history has several important implications for oil and gas exploration. I speak now only of what we have learned in the concessions Union has explored. The geology may differ somewhat in other parts of the Basin.

1. This type of non-marine sedimentation results in a very erratic, unpredictable distribution of sandstone reservoir beds. There are no widespread sandstone beds, uniform in thickness and in reservoir quality, over large areas.

2. There is an extraordinary number of very closely spaced faults, which offset the reservoir beds, and which divide a gas field into a multitude of separate gas accumulations, each fault-separated and pressure-separated from the other accumulations.

3. The temperature gradient in the Pattani Basin is very high. Temperatures at about 2.5 kilometers are 170 degrees Celsius. This temperature gradient is higher than in almost any gas field in the world, and it may be the reason the basin is prone to yield gas.
4. These complex geologic conditions make the Pattani Basin difficult to explore. If gas is found, they make it difficult to develop the field. It is necessary to drill a large number of wells to adequately drain the reservoirs. An obvious corollary is that a much greater capital investment is required to produce a given quantity of gas than is usually the case.

After this generalized description of the Pattani Basin, let us turn to Union's four concessions, and to the individual gas fields.

SLIDE 4 CONCESSIONS

This map shows the area which Union, Seapec and Moeco currently retain as production areas and reserve areas. The two Gas Sales Contract areas are outlined in black. Gas fields that are being developed under these two sales contracts are: Erawan, Baanpot, Satun and Platong. Other discoveries within these contract areas are Pladang, North Pladang and Kaphong. These latter discoveries will require more investigation before it can be determined if they are large enough to be developed.

Several structures outside the two contract areas also have tested gas. These are Pakarang, Trat, Jakrawan and Funan. These are as yet only partially defined and additional detailed seismic surveying, and delineation drilling will be needed before a decision on development could be made.
The most sophisticated exploration technology is being applied. A breakthrough in seismic technology came several years ago with the development of 3-Dimensional surveying. Up to that time seismic surveys were conducted on a rectangular grid, with lines spaced perhaps one kilometer apart. 3-Dimensional surveying consists of extremely closely spaced lines, all shot in one direction, with line spacing of 75 meters. We have 3-D surveys over the four fields we are developing.

Powerful computers are needed to handle the vast database. An advanced version of the very latest developments in computer-assisted interpretation methods is now being installed in our Bangkok office. We will have interpretation capabilities as advanced as anywhere in the world.

SLIDE 5 MAP OF ERAWAN FIELD

This is a map of the Erawan Field in its present stage of development. The black squares are the eight well platforms which have been installed. Two additional platforms are under consideration in the northern part of the field, where successful delineation wells have been drilled from templates set on the sea floor.

Up to 12 wells are directionally drilled from each platform. The course of each well is shown, as well as the location at which it bottomed. This is a plan view and it does not indicate how deep the wells went, or at what depths they encountered gas sands.
62 wells have been drilled at Erawan to date, and at present 42 wells are on production. Tender-assisted rigs are drilling on "F" and "G" platforms, and a drill-ship is drilling through a sea-floor template north of the "D" platform. One rig is doing a workover on the "C" platform.

SLIDE 6 MAP OF PLATONG FIELD

This is the current stage of drilling at Platong field. Three platforms were set in 1982 and 30 wells have been drilled to date. One rig is currently drilling at the "C" Platform.

One well platform was installed at Baanpot field in 1983, and the eighth well from that platform is now drilling. Studies are in progress to determine locations for two additional well platforms.

SLIDE 7 WELL CORRELATION SECTION

This slide shows electric logs of 5 Baanpot wells. As we have already mentioned, sand beds are very lenticular, and rarely correlate from well to well. Shale beds and coal beds are usually more widespread, and they provide markers which correlate one well with another. In this section, a few shale and coal beds have been correlated from well to well.
The red dots are gas sands encountered in each well. This illustrates the random and localized occurrence of pay sands. Most of the gas at Baanpot occurs between 5,250 feet and 7,250 feet below sea level. The majority of gas sands at Erawan occur between 5,000 feet and 8,500 feet subsea. Individual sands range in thickness from a few feet to 40 feet. Rarely is there a pay sand greater than 40 feet. An average well will have 6 or 7 pays.

A correlation section through Erawan or Platong would be similar to this Baanpot example.

Many people have expressed an interest in the reserves at Erawan. I think you will appreciate from the preceding slides, the difficulty of determining reserves prior to drilling a large number of wells, and to having production histories from those wells. These slides also show that a great deal of study has to go into the location of well platforms, and indeed to every well that is drilled from the platforms, in order to maximize the opportunities for it to encounter sufficient pay to be commercial. Each development well has to be approached as if it were an exploratory well.

The Erawan Gas Sales Agreement was signed with PTT in September, 1978. Bids were immediately invited for the fabrication, transportation and installation of well platforms, processing platforms, and a living-quarters platform. An oil tanker was extensively modified so it could serve as a permanently anchored condensate storage facility.
Development drilling from the well platforms started January 1980.

While Union and Seapec were carrying out the Erawan development operation, PTT was laying the 425 km. offshore pipeline and the 160 km. onshore pipeline.

First production at Erawan commenced August, 1981, three years after the Gas Sales Agreement was signed.

A Second Gas Sales Contract was signed in May, 1982. This covered the Baanpot, Satun, Platong and Kaphong fields. Production from Baanpot started in October, 1983, and Satun and Platong fields will be producing by early 1985, 2 1/2 years after signing the Sales Contract.

When it became apparent that Erawan production would not reach the anticipated levels, Union proposed accelerating development of the Second Contract by amending it to permit Baanpot to be developed as a supplement to Erawan. By bringing Baanpot gas to Erawan and utilizing Erawan's facilities, it would be possible to commence Baanpot production 14 months early. PTT agreed and a well platform under fabrication for another field was modified and installed at Baanpot. The first Baanpot well spudded July, 1983, only 3 months after signing the agreement. Production started Oct. 20, 1983, 6 1/2 months after the agreement was signed.

Production has steadily increased from 105 million cubic feet per day a year ago, to 185 million cubic feet at present from Erawan and Baanpot fields. Platong and Satun fields will commence production in early 1985. Production from the four fields is expected to
average about 325 million cubic feet per day in 1985, together with 12,000 barrels of condensate per day. We anticipate production will increase in 1986 but some production history will be needed on fields in the Second Gas Sales Contract before we would forecast production levels beyond next year.

Mr. Martin Miller, Vice President of Operations, is responsible for all of the drilling and production operations. Mr. Miller will now describe the physical layout, and the current operations.
Thank you Dr. Lian. I would like to review Union Oil Co. of Thailand's offshore development projects. Union and its coventurer South East Asia Petroleum Exploration Company are currently involved in the development of the Erawan field which is located in the G.O.T. approximately 266 miles South of Sattahip and approximately 120 miles Northeast of Songkhla. The water depth is about 220'.

Production from the field started in August, 1981. At that time, the field facilities consisted of 5 well platforms, 4 remote gas processing platforms, one central processing platform, one living quarters platform and one floating storage tanker.

This is an artist's representation of the platforms and interconnecting pipelines as they were at the start of production. Each of the remote processing platforms is linked to the central processing platform by a 16" gas pipeline and a 6" condensate pipeline. The floating storage tanker is linked to the central processing platform by a 6" condensate line.
This is a typical well platform with a tender supported drilling rig in operation. This type of drilling rig is used to drill most of the development wells. The tender unit is moored next to the platform with anchors which are deployed by anchor handling tug boats. Main facilities on the tender are electrical power generators, mud pumps, cementing pumps, mud tanks, bulk mud and cement storage, sack storage, tubular storage, a well logging unit, and crew accommodations for approximately 100 personnel.

Service lines connect the tender to the drilling unit which is located on the platform. Each well platform is designed for the drilling of 12 development wells. Usually, the first well is drilled vertically and subsequent wells are directionally drilled to predetermined bottom hole locations which can be as far as 8,500' away from the platform. Production from each development well is collected in a common manifold and piped to a processing platform which is bridge connected to the well platform.
This is a typical Erawan field remote gas processing platform. The platform's main process and utility systems are gas, condensate and water separation facilities, gas dehydration facilities, power generation facilities, and well testing facilities. The separated condensate is pumped to the central process platform via a 6" pipeline. The dehydrated gas also flows to the central process platform but via a 16" pipeline.

This is the Erawan field central processing and living quarters complex. The central processing platform is on the right, the living quarters platform is in the rear, and well platform 'A' is on the left along with a tender supported drilling rig. This is the central processing platform. All produced gas and condensate is collected here. Also, the entire field operation is monitored from the platform's central control room. The dehydrated gas from each remote process platform is collected and measured before entering
PTT's 34" gas pipeline. The current Erawan sales gas quality is as follows:

- Water Content; less than 7 lb/MMCF
- Sulfur; less than 1000 grains/100 CF
- H2S; less than 100 grains/100 CF
- CO2; less than 18 mol percent
- O2; less than 0.1 mol percent
- Heating Value; 1150 BTU/CF

The condensate is processed for storage in a floating storage tanker which is located approximately 2 miles from the central process platform. The vessel is permanently moored to a floating buoy which is designed to allow the tanker to rotate around the buoy as prevailing wind and sea conditions dictate. The vessel's maximum capacity is approximately 660,000 barrels.
This is the Erawan field living quarters platform which is bridge connected to the central processing platform. The accommodation building includes food preparation and dining facilities, recreational facilities, offices and living accommodation for 120 personnel. Below the accommodation module is an equipment storage area, workshops, and emergency power generation facilities. Communication to shore is via a satellite link to the Thailand telephone network.

Since coming onstream in August 1981, three additional well platforms have been installed. This is an artist's representation of the field as it is today. Platforms F and G were installed in 1983 on the western flank of the field. Production from these platforms started in late 1983 and development drilling is underway at both locations. Platform H was installed in January 1984 on the field's extreme northeastern flank. Three wells were drilled by a
drillship through a template on the sea floor before the decision to set a platform was made. The platform was installed over these wells and they will be recovered when a drilling rig is installed on the platform. Recovery of these wells will accelerate the platform's production rate. Development drilling from the platform using a tender type rig is scheduled to start in April. Another significant field addition was the installation of 21,000 BHP of booster compression facilities during 1983. Two compressor units have been installed on the central processing platform, two units on the remote process platform B and single units have been installed on remote process platforms C and D. These compressor units serve two purposes. First, well productivity is significantly improved by lowering the wellhead flowing pressure. Second, the compressors will result in a higher recovery of gas reserves by lowering the downhole abandonment pressure. The current production rate is 160 MMCF/D of gas and 6,000 B/D of condensate. We expect this production rate to be maintained or at a slightly lower level for the next two or three years.
In addition to the Erawan field development, Union and its coventurers Seapec and Mitsui Oil Exploration Co. are developing 3 additional Gulf of Thailand gas fields. One of them, the Baanpot field, is already on production. The field is located approximately 17 miles Southeast of Erawan. To augment Erawan's production rate, Union proposed to accelerate the Baanpot field development. On October 20, 1983 the field started production only 6 1/2 months after finalizing the acceleration agreement with the Thai government.

This is an artist's representation of the Baanpot well platform and its pipeline connection with the Erawan field processing and gathering system. The well platform is very similar to Erawan well platforms F, G and H. Production from the platform flows via a 16" pipeline to Erawan remote process platform C. All of the Erawan well platform C production has been diverted to Erawan
remote process platform E via a 10" pipeline which was installed as part of the acceleration project. The process facilities on Erawan remote process platform C are utilized for the Baanpot production. The dehydrated gas is measured separately from the Erawan gas before it is commingled in the 34" PTT gas pipeline. Sales gas quality is very similar to that of Erawan. The Baanpot condensate is commingled and processed with the Erawan condensate and is stored in the floating storage tanker. The current field production rate is 25 MMCF/D gas and 1500 B/D condensate.

Another field being developed is named Platong and is located approximately 40 miles north of Erawan. The Platong field development plan calls for installation of 4 remote well platforms, a central process platform and a living quarters platform. The 4
remote well platforms are designed for 12 development wells. Production from each of these platforms will flow via a single pipeline to the central processing platform which will include gas, condensate and water separation facilities, gas compression and dehydration facilities, gas hydrocarbon dew point depression facilities, condensate stabilization facilities and the associated utility systems.

The stabilized condensate will be pumped through Union's condensate pipeline network and eventually end up at the Erawan field floating storage tanker. After measurement, the sales gas will flow into a 24" spur pipeline which connects to PTT's main 34" gas pipeline. The 24" spur pipeline will be installed and operated by PTT.

Platong field gas quality is expected to be as follows;
- Water Content; less than 7 lbs/MMCF
- Sulfur; less than 1000 grains/100 CF
- H2S; less than 100 grains/100 CF
- CO2; less than 23 mol percent
- O2; less than 0.1 mol percent
- Heating Value; less than 1150 BTU/CF
- Hydrocarbon Dew Point; less than 60°F at any pressure below 1150 PSIG

At the present time, three of the four remote well platforms have been installed. The jackets for the central process platform and living quarters platform are being installed. The fourth well platform the central process platform deck and the living quarters deck will be installed later this year. Approximately 50 percent of the field's development drilling has been completed. We expect production to start in early 1985.
The other field being developed is named Satun and is located approximately 16 miles to the Northeast of Erawan. The development plan concept is the same as at Platong. However, 7 remote well platforms will be installed. Production from each well platform will flow to a Central Process Platform which has been designed to handle a gas throughput approximately 50% greater than at Platong. Sales gas from Satun will flow via a 16" pipeline to the Erawan central process platform where it will be separately measured before entering PTT's 34" pipeline. Satun gas quality is expected to be very similar to that of Platong. Stabilized condensate will enter Union's condensate pipeline network and end up at the floating storage tanker at Erawan.

At the present time, five of the seven well platforms have been installed along with the jackets for the central process platform and the living quarters platform. Development drilling is scheduled to start in May of this year. Two additional well
platforms, the central process platform deck and living quarters
deck will be installed later this year. We expect to start
production in early 1985.

In addition to these offshore facilities, Union operates
onshore facilities at Songkhla and Sattahip. At Sattahip, Union
operates a shore base to support the six drilling rigs currently
working in the Gulf. The shore base includes an 11 acre oilwell
tubular and equipment storage area, a 30,000 square foot warehouse,
a bulk storage facility for drilling mud components, a bulk cement
storage facility, and a deep water dock used for loading supply
boats.

At Songkhla, Union operates a shore base to support
production operations. The shore base includes a 40,000 square foot
warehouse for storage of equipment, spare parts and operating consumables. Also, Union operates a helicopter hangar designed to accommodate the Sikorski S-76 helicopters which transport personnel to and from the various platforms, drilling rigs and construction vessels. Also located at Songkhla is Union's training center.

Since beginning operation in 1980, approximately 186 Thai nationals have been trained as production operators, mechanics, electricians and instrument technicians. At the present time, another group of trainees are at the center in preparation for the start of production from the Platong and Satun fields. The primary areas of instruction are English language, petroleum technology, craft workshop skills, safety and fire fighting. Union currently employs 59 expatriate employees to operate and maintain offshore production facilities. By the end of 1987, we expect most of these expatriates will be replaced by Thai Nationals who have gone through the training center.
Development of the Erawan, Baanpot, Platong and Satun fields requires the utilization of a variety of drilling, construction and logistical support equipment. The following is a summary of major equipment items currently being utilized:

- five tender supported drilling rigs
- one drillship
- one 725 ton derrick/lay barge
- one hook-up barge
- nine drilling, construction, and production support vessels
- three crew boats
- three Sikorsky S-76 helicopters

The total number of personnel directly involved in Union's offshore operations exceeds 2,000. This includes Union and contractor staff involved in the operation and maintenance of the
Erawan and Baanpot fields as well as contractor personnel involved in the operation of the drilling rigs, construction equipment and support vessels. In addition, approximately 500 personnel are employed at Union operated onshore locations.

1983 was a very active year for Union. During the year, 69 development wells were drilled, 7 new well platforms were installed and three were brought onto production. Fabrication of another new well platform was completed. 21,000 BHP of compression facilities were installed at the Erawan field. 27 miles of pipeline were installed. Contracts were awarded for 5 additional well platforms to be installed in late 1984.

This high level of activity will certainly be maintained through 1984. The current rate of expenditure is over $1 million per day. The Platong and Satun gas fields will start producing in
early 1985. There will be 31 offshore structures and a floating storage tanker all connected by approximately 172 miles of pipelines excluding those pipelines installed and operated by PTT. I hope you have a better understanding of Union's operations.
TEXAS PACIFIC THAILAND
"B" STRUCTURE
GULF OF THAILAND

Natural Gas Utilization Symposium
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Bangkok Thailand
Texas Pacific began its search for hydrocarbons in Thailand in 1976 by acquiring two concessions. One of the concessions was obtained from Tenneco Thailand, Inc. and the other from BP Petroleum Development of Thailand, Limited. Both concessions were farmed-in with drilling commitments required on each as part of the farm-in transactions.

The location of Texas Pacific's holdings, including "B" Structure, is shown on Figure 1. They are about 135 miles northeast of Songkhla and about 110 miles south and slightly east of Union's Erawan Field. Texas Pacific Thailand is the operator of both concessions and our co-venturers are Canadian Superior (Thailand) Limited, of Calgary, Alberta, Canada; Highland Thailand, Inc., of Houston, Texas; and Thai Offshore Investments Ltd., of Bangkok. The respective ownership in each concession is also shown on Figure 1.

Geologically, the concessions are located on the northeast hingeline of the Malay Basin (Figure II). This area is slightly northeast of the Narathiwat high which has a granite core and is found as shallow as a thousand feet below the surface. The Narathiwat high is indicated to be the primary source of clastics comprising the "B" Structure lithology.

Figure III schematically shows "B" Structure lithology. Numerous hydrocarbon and water-bearing reservoirs are found to depths below 10,000 feet in a long sand-shale sequence of lower-middle Miocene age.

Two environments of deposition are observed when analyzing this lithological sequence. The depositional environment of the deeper sands or "red beds", which occur below 7,000 feet, is continental. These sands
are generally coarse grained, well sorted, contain small amounts of associated clay minerals and extend over wide areas. The claystones in this section are orange-brown to brick-red in color.

The sands above the "red beds" occur within a cyclic alternation of alluvial channel sands, coal beds, gray clays, mudstones and silts which are lagoonal in origin or originate in equatorial mangrove swamp environments. The sands are fine to medium in size, moderately sorted, gray to buff or light brown in color.

The hydrocarbon trapping mechanism is both structural and stratigraphic. However, it is uncertain which is the more predominant.

Since the area is located on the hingeline of the Malay Basin, there is, of course, faulting contributing to the trapping mechanism. Faults are, without exception, normal or tensional and can be mapped by reflection seismic techniques.

Figure IV shows a structural interpretation of "B" Structure, mapped on a 4,500-foot horizon. The entire complex is about 42 miles long and from 3 to 8 miles wide. Numerous faults can be seen, many of which are en-echelon and spaced from a mile to a mile and one-half apart.

The validity of structural interpretation and determination of fault density is contingent upon seismic grid density. Early drilling and drillstem test results in "B" Structure indicated that the then-available wide seismic grid was not adequately defining the structure and fault system. In late summer of 1977, Texas Pacific engaged G.S.I. to conduct a 3-D seismic survey. The 3-D area shown on Figure IV was shot in an east-west direction along 118 lines spaced 100 meters apart. Additionally, 10 lines were shot to tie in two gas wells drilled previously by Tenneco. The resulting interpretation of this data indicated a higher degree of faulting than was previously shown to be evident.
Traps occur adjacent to the larger faults on both the upthrown and downthrown sides. Additional traps occur near the axis of "rollover" folds often located between faults in graben features. Structural traps are abundant and similar to those known in many of the world's hydrocarbon productive basins.

As to the stratigraphic component of the trapping mechanism (Figure V), many sands have been deposited over a fairly large area, some of which have been cut by channels with the channels later filled with claystone and shale. Conversely, some shales in the sequence have been cut by channels and later filled with sand. Other sands have been deposited as bars which may or may not have been cut by channels.

The "B" Structure (Figure IV) was discovered in the fall of 1976 with the drilling and testing of the 15-B-4X well. Later, however, it was found that three previously drilled Tenneco wells, the 15-B-1X, 2X, and 3X, and one BP well, the 16-B-1, were also to become a part of the "B" Structure complex.

The 15-B-4X well was drilled to a total depth of 8,050 feet. Pipe was set and the well tested through perforated casing. Fourteen sands were indicated to be productive from drilling data and log analysis, of which six were drillstem tested (Figure VI). All six zones were gas productive. Gas flow rates ranged from 2 to 14 MMCF per day with flowing surface pressures from 700 to 1,600 psig.

Over the next six years, 18 additional "B" Structure exploratory and delineation wells were drilled bringing the total well count to 23, including the earlier Tenneco and BP wells. Of this total, the 15-B-9X well was dry and 16-I-1 results are questionable. The success ratio in the "B" Structure has been over 90 percent.
Plans for drilling and testing of all wells included an extensive formation evaluation program. The log suite obtained included FDC/CNL, ISF/Sonic, and Laterolog. Composite logs and drilling evaluation logs were obtained. A velocity survey and dipmeter were also run.

Formation fluid content and pressure data were initially obtained with either the wireline RFT and F!T tools. On occasions, both tools were utilized. Zones were selected as drillstem test candidates based on interpretations of all log information in conjunction with RFT-FIT data.

Drillstem tests were of the two-flow short duration type. Initial flow was normally 30 minutes followed by an initial shut-in of one hour. Final flow ranged from three to six hours depending upon the time required for production rates to essentially stabilize. Final shut-in time was approximately equal to the combined time of the prior flow and shut-in periods. Samples of reservoir fluid (oil, condensate, water) were taken immediately prior to final shut-in. All fluid samples were shipped to a commercial laboratory for analysis.

Pressure charts were read and a preliminary DST analysis was made on-site which included a determination of reservoir pressure, skin damage, permeability, and boundary conditions. A detailed analysis of the test was later made in Dallas using complex reservoir modeling techniques. A total of 120 drillstem tests have been run on "B" Structure wells which averages 5 per well.

It is from the analysis and interpretation of the DST data that provide the basis for our projections of (Figure VII):

a) gas well deliverability characteristics
b) drainage area
c) composite gas composition
d) BTU content
e) condensate yield
By defining the deliverability characteristics of the sands and by using a two-dimensional radial flow reservoir model, we were able to forecast the timing of installation of development drilling platforms and the number of these platforms required to provide and maintain pre-determined annual gas sales rates.

These projections, in turn, were used to analyze the commercial viability of developing "B" Structure for potential sales of gas and condensate.

Figure VIII shows that portion of "B" Structure selected for initial development of the project. There are 20 wells within the project area including the 15-B-9X which was non-productive. The area of 3-D seismic coverage is also shown on this figure. The project area extends from the 16-B-1 well on the south to 15-B-1X well on the north. The project area is about 20 miles long and 8 miles wide.

The next figure (Figure IX) shows the reservoir distribution and characteristics within the proposed project area. The average well contains eight hydrocarbon-bearing sands having a total net pay thickness of 126 feet. The average hydrocarbon-bearing sand is 16 feet thick, has a porosity and water saturation of 21 and 43 percent, respectively.

The reservoir fluid consists of essentially dry gas in the "red bed" section (below 7,000 feet) with a relatively high carbon dioxide content in the range of 30 to 35 percent. Gas deliverability from the "red bed" section is excellent. Above the "red beds", both gas and condensate are produced. The gas contains about 15 percent carbon dioxide with the gas from the shallower zones being essentially free of CO₂. Figure X shows the increasing trend of inert gas contamination with depth.

Figure XI is a pressure-depth profile. These data show that the proposed project area is normally pressured with a gradient equivalent to that of fresh water. The temperature gradient in the area is shown on Figure XII. Temperatures within the prospective producing section range from about 330 degrees F at 8,000 feet to near 200 degrees F at 3,000 feet.
Development of "B" Structure will be initially directed toward providing a gas sales rate of 150 million cubic feet per day to be delivered to PTT from a central production platform. Equipment will be sized and initial plans made for increasing the sales rate to 250 million cubic feet per day according to the schedule shown on Figure XIII. This schedule will initially require three drilling platforms, each with ten producing wells. Producing wells will be completed with dual tubing strings. The lower zones, which are high in CO₂ and highly productive, will be produced through one of the tubing strings. The upper zones, containing condensate and gas of low CO₂ content will be produced through the second string. Each tubing string may contain production from one or more individual sands which will be commingled downhole.

The resulting production will then be commingled at the surface at each platform and between platforms to provide a combined gas sales stream with an average CO₂ content of 23 percent, a heating value of 875 BTU per cubic foot and having a condensate yield of 12 barrels per million.

Figure XIV is a schematic drawing of the facilities when the project is fully developed to produce the 250 MMCF/D gas sales rate. The platforms colored in green represent the installation necessary to produce the initial rate of 150 MMCF/D.

The facilities include a central terminal complex consisting of a 12-slot, 8-pile drilling platform and an 8-pile combined central production and compression platform with flare tripod and bridge; 12-slot satellite drilling platforms, each with flare tripod and bridge; flowlines connecting the satellite drilling platforms to the central production/compression platform; a single point mooring system for loading of associated condensate into a permanently moored storage vessel with shuttle barging of the condensate to shore.

It is proposed to have the central production platform serve as a self-sustained central production/compression complex. It will contain all of the necessary production and processing facilities, together with compression, condensate storage, utilities, communication systems and quarters. Compression facilities will, when necessary, increase the pressure from 300 psig to
800 psig for delivery to PTT. The satellite drilling platforms will also contain the minimum production and treating facilities required to deliver the natural gas with condensate to the central production platform. A single point mooring system for handling of the condensate will be connected by a flowline to the central production platform. Gas from the central production platform will be delivered to PTT at a pressure of 800 psig. PTT will receive the gas at its platform at 800 psig where the gas will be compressed to 1,250 psig for transmission to shore.

Implementation of these plans for development of "B" Structure is contingent upon negotiating a satisfactory gas sales agreement with the Thai Government. Discussions are presently continuing toward this objective. We are hopeful that these current discussions can be favorably concluded in the not-too-distant future.
FIGURE I

BLOCKS BLOCKS
14-15 16-17

TEXAS PACIFIC 68.1700 93.0000
CANADIAN SUPERIOR 17.7700 5.0000
HIGHLAND 4.0500 2.0000
TOIL 10.0000 NONE
PRE-TERTIARY BASEMENT FEATURES

FIGURE II
FIGURE III
SCHEMATIC LITHOLOGICAL LOG
WELL 15-B-4X

DEPTHS, FEET

19 3/8" CASING 3,533 ft.

6500
5000
4000
3500

SAND
SHALE
SHALE

TOP OF RED BEDS 7,216 ft.

9 5/8" CASING 7,999 ft.

104
AREA OF 3-D SEISMIC SURVEY
GAS PRODUCTIVE OR POTENTIALLY PRODUCTIVE
EXPLORATORY OR Delineation Well

STRUCTURAL INTERPRETATION "B" Structure

FIGURE IV
FIGURE V

SCHEMATIC CROSS SECTION OF DEPOSITIONAL FEATURES

CHANNEL SAND SHALE

SHALE CHANNEL SAND BAR SHALE

SHALE CHANNEL SHEET SAND
DRILL STEM TEST DATA PROVIDED:

1. GASWELL DELIVERABILITY CHARACTERISTICS
2. DRAINAGE AREA LIMITATIONS
3. COMPOSITE GAS COMPOSITION
4. BTU CONTENT OF SALES GAS
5. CONDENSATE YIELD

FIGURE VII
## Reservoir Distribution Sand Characteristics

### Per Well Average
- Number of Hydrocarbon-Bearing Sands: 8
- Net Pay Thickness, Feet: 126

### Average Hydrocarbon-Bearing Sand
- Thickness, Feet: 16
- Porosity, Percent: 21
- Water Saturation, Percent: 43

**Figure IX**
FIGURE X
PRESSURE-DEPTH PROFILE
SOURCE: DST DATA

PRESSURE = 0.433 \times \text{DEPTH}

FIGURE XP
TEMPERATURE-DEPTH PROFILE
SOURCE: DST DATA

TEMPERATURE = $115^\circ + 2.71^\circ/100$ FEET

FIGURE XII
<table>
<thead>
<tr>
<th>YEAR OF SALES</th>
<th>SALES RATE MMCF/DAY</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>150</td>
</tr>
<tr>
<td>2</td>
<td>150</td>
</tr>
<tr>
<td>3</td>
<td>200</td>
</tr>
<tr>
<td>4</td>
<td>250</td>
</tr>
</tbody>
</table>

FIGURE XIII
AN OVERVIEW OF WORLDWIDE STANDARDS FOR NATURAL GAS UTILIZATION.

Elisabeth M. Drake, Northeastern University
and Marian H. Long, Arthur D. Little, Inc.

ABSTRACT:

As countries develop their natural fuel resources, governments and industries are faced with many decisions about what standards should be set to establish the levels of safety they wish. In countries where technology is well established and standards have evolved for fifty years or so, society seems willing to accept somewhat higher levels of hazard than in countries just developing the resource involved.

This paper will define natural gas utilization broadly to include: "natural pipeline gas" (primarily methane), "LPG" (primarily propane and butane stored under pressure as liquids), and refrigerated liquified gases such as liquified natural gas (LNG) and liquified ethane or ethylene and liquified propane.

For these natural gases, we examine major existing practices and standards worldwide and some of the factors of concern for countries in the process of establishing their own standards today as energy resources are developed, processed and introduced into consumer markets.
1. Introduction

Safety and operability criteria have accompanied the development of technology and have evolved with it. In the earliest form something would be designed and built and people would find out by experience how it performed. For example, boiler explosions occurred in some of the first steam locomotives constructed. To improve public safety, early railroad operators placed an extra wagon loaded with a buffer material behind the locomotive. Concurrently, advances were made in the design of the steam boilers to make operation more reliable and to prevent the destruction of a valuable piece of equipment. Today very detailed codes and standards govern design and construction of pressure vessels and, with good maintenance, failures have become very rare indeed.

A similar pattern was followed in the development of standards for natural gases and liquids. Industry has a basic need for some standards which will, as a minimum,

- assure that the facility will operate reliably, thus protecting the investment in the facility and the profits from its operation,
- prevent less responsible members of industry from operating in a manner which could give the industry a bad name,
- provide an environment in which employees will work without fear, and,
to provide an "acceptable" level of safety to the users of the fuel and to the public in general, so that the processing, transport, storage and end use of the fuel will continue and be viewed as a benefit to society.

Since the trade-offs between safety and profitability are difficult to make and since, after a reasonable safety level is achieved, incremental safety becomes increasingly expensive, members of industry sectors tended to cooperate in establishing minimum standards. In the United States, groups like the National Fire Protection Association (NFPA) and the American Petroleum Association (API) formed committees comprised of member representatives to establish minimum standards. These groups did a good job considering the difficulty of their task and remained active to update standards as knowledge increased and new technology developed.

Professional societies such as the American Society of Mechanical Engineers (ASME) also formed committees to develop and keep current standards covering a wide range of subjects: material selection, design of pressure vessels, proof testing, etc.

In England, the Institute of Petroleum (IP), the Institute of Gas Engineers (IGE), and the Royal Society for the Prevention of Accidents (ROSPA) performed analogous functions.
However, people are imperfect and committees tend to operate in a somewhat random manner, as all of us who have served on committees know. Thus, unfortunately, some changes in codes, standards, and practices are due to the occurrence of unexpected accidents. Accidents also occur randomly, so it is not surprising that industry standards are somewhat uneven in the levels of safety provided. A further complication is the fact that larger companies tend to control the highest level of expertise and often have different attitudes than smaller companies who are less sophisticated and may bend industry standards either inadvertently or through a desire to stay in business. The possibility also exists that larger companies can hurt the competitive position of responsible smaller companies by enacting overly stringent industry standards.

Thus, in the continuing evolution, governmental groups assumed their responsibilities with regard to adequately protecting public safety. The way in which governments choose to set levels of safety and the philosophy for enforcement varies considerably from country-to-country. This will be discussed further after a brief description of the characteristics of the various natural gases and liquids, produced as a multicomponent mixture, which then can be separated and processed to yield a variety of end products.
2. Use and Properties of Natural Gases and Liquids

These hydrocarbon gases are often found in association with oil and can be separated by pressure reduction and fairly simple processing. The most volatile component, methane, is a gas at ambient temperature and can be transported through high pressure pipelines for distribution and use in higher density population centers. It can also be used as a feedstock to produce ammonia and methanol. For marine export, it is most cost effectively transported as a low temperature liquid at -162°C in specially insulated marine tankers. This liquefied natural gas (LNG) is more energy efficient than methanol fuel.

At atmospheric pressure, propane liquefies around -40°C and can be held at ambient temperature as a liquid at pressures of around 10 bars. (The pressure increases as ambient temperature increases.) Table 1 shows typical properties of LNG, LPG and similar fuels. Most of us are familiar with pressurized LPG which is widely used as a fuel by people in areas not served by natural gas distribution systems, for cooking and heating in recreational vehicles and as an alternative fuel for automobiles. While uninsulated pressurized storage of LPG is feasible for relatively small quantities of fuel, quantities in excess of a few thousand cubic meters (liquid) are more economically transported as a low temperature liquid at just above atmospheric pressure. Most large marine transportation projects involve refrigerated LPG or LNG.
<table>
<thead>
<tr>
<th></th>
<th>Methane</th>
<th>Ethylene</th>
<th>Ethane</th>
<th>Propane</th>
<th>n-Butane</th>
<th>C₅⁺</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Chemical Formula</strong></td>
<td>CH₄</td>
<td>C₂H₄</td>
<td>C₂H₆</td>
<td>C₃H₈</td>
<td>C₄H₁₀</td>
<td>C₅⁺</td>
</tr>
<tr>
<td><strong>Molecular Weight</strong></td>
<td>16</td>
<td>28</td>
<td>30</td>
<td>44</td>
<td>58</td>
<td>86</td>
</tr>
<tr>
<td><strong>Atmospheric Boiling Temperature (°C)</strong></td>
<td>-162</td>
<td>-104</td>
<td>-89</td>
<td>-42</td>
<td>0</td>
<td>47</td>
</tr>
<tr>
<td><strong>Liquid Density at Atmospheric Boiling Point (kg/m³)</strong></td>
<td>427</td>
<td>567</td>
<td>544</td>
<td>583</td>
<td>602</td>
<td>656</td>
</tr>
<tr>
<td><strong>Vapor Density at Atmospheric Boiling Point (kg/m³)</strong></td>
<td>1.75</td>
<td>2.09</td>
<td>2.06</td>
<td>2.43</td>
<td>2.71</td>
<td>3.0</td>
</tr>
<tr>
<td><strong>Vapor Pressure (atm) at 50°C</strong></td>
<td>N.A.</td>
<td>N.A.</td>
<td>50</td>
<td>18</td>
<td>5</td>
<td>1</td>
</tr>
<tr>
<td><strong>Lower and Upper Flammable Limits in air (mol.%)</strong></td>
<td>5-15%</td>
<td>3.1-12.5%</td>
<td>3.0-12.5%</td>
<td>2.1-9.5%</td>
<td>1.9-8.5%</td>
<td>1-7%</td>
</tr>
</tbody>
</table>
Ethane can be used as a feedstock to produce ethylene or can be divided between natural gas and LPG products for use as a fuel.

3. Overview of Major World Standards

Most European countries, Australia, New Zealand, Canada, and Japan have a procedure where the owner of a major proposed hazardous facility (LNG, LPG or various other flammable or toxic materials) must apply to a local or regional group for permission to proceed with construction. In Britain, an applicant provides information on proposed project design and potential impacts - environmental, safety and societal. Initially, the regional group will give outline planning permission after public hearing if the project seems desirable. Conditions may be attached to this planning permission which may impose further requirements such as an independent safety audit conducted to the satisfaction of the Health and Safety Executive. These conditions may add some requirements which exceed normal industry practices and codes. It is also common practice in Britain to have a government energy company involved as a partner in larger projects.

Countries like Canada, New Zealand and Australia tend to follow the British practice of application to local authorities, public hearing and planning permission. In Japan, a similar system also seems to be followed, with the local
authority often assembling an advisory panel of experts to assist them in more complicated technical issues. The Ministry of Industry and Trade (M.I.T.I.) is the governmental group which works with industry in the development of general standards and practices.

In September 1980, Germany passed a Chemicals Acts with the purpose of protecting man and the environment from the harmful effects of dangerous substances. The Act defines dangerous substances (toxic, flammable, corrosive, explosive, carcinogenic, etc. materials). A manufacturer of a new dangerous substance is required to notify the government at least 45 days before initial circulation of the product. (Parallel requirements are being developed among other countries which are members of the European Communities.) The government has the authority to prohibit or limit the use of substances creating undue risk to human life, health or the environment. The Bundesrat authorized development of regulations covering occupational and public safety with respect to dangerous substances.

Regulations covering marine transport do not vary very much worldwide, since the International Maritime Consultative Organization (IMCO) has adopted standards which are essentially the same as US Coast Guard standards.

In the United States Congress has legislated responsibility for setting standards for hazardous materials, including the fuels of interest here, to large government agencies—in particular the Department of Transportation (which includes
the Coast Guard, the Federal Railroad Administration, the Federal Highway Administration and the Materials Transportation Bureau). These agencies develop independent standards which vary from incorporation of industry standards by reference to the generation of detailed standards which exceed prior industry practice in a number of respects.

4. Continuing Evolution of Standards

Standards seem to evolve because of two major factors; developing technology and occurrence of failures. In the U.S., development of government standards is also dependent on political factors and can be influenced by public perceptions of risk due to press coverage of major accidents. The development of LNG standards in the U.S. is a good example of such evolution.

In 1941, the East Ohio Gas Company tried a pioneering experiment. They built a LNG peak facility in Cleveland, Ohio. The project was successful and additional tanks were added - in spite of war-time shortages of nickel, a key component in the steel alloy required for the low storage temperature. In 1944, one of the newest tanks failed due to brittle metallurgical fracture. The spilling cold liquid overflowed dikes designed for slow leaks, spread rapidly into the adjacent street located about 20 m away, boiled rapidly and vaporized. The vapors mixed with air and soon reached a source of ignition causing a fire in which 128
people died - most of them gas company workers in a building near the storage tank.

This disaster aroused great concern, both from the public, government groups, and the gas industry eager to try the new technology. Nearly two decades passed until this form of natural gas system peak shaving was tried again.

In the interim, the National Aeronautics and Space Administration (NASA) and the Department of Defense (DOD) became interested in cryogenic (low temperature) rocket fuels and oxidizers. Much research was conducted for metals capable of containing liquid hydrogen (normal boiling point of \(-253^\circ C\)) and liquid oxygen (normal boiling point of \(-184^\circ C\)). This work provided knowledge about improved cryogenic materials and procedures for safe handling of cryogens. While storage of liquid oxygen required stainless steel (18% nickel), it was found that warmer LNG storage required 9% nickel steel - the steel at Cleveland had been about 3.5% nickel.

The other hazardous materials industries continued to operate along the guideline of industry standards. With the increase in trucking and pipelining as well as the deterioration of rail systems, hazardous material transportation accidents increased. Concern tended to shift toward public sector regulatory control. The Natural Gas Pipeline Safety Act of 1968 gave the U.S. Department of Transportation (DOT) responsibility for natural gas pipelining and facilit-
ies attached to the system. Thus, DOT has control over LNG facilities connected to the natural gas pipeline networks. The U.S. Coast Guard (USCG) was given jurisdiction over all marine shipments including those involving a wide variety of toxic, flammable and explosive materials.

In the 1960's, gas companies again started constructing LNG facilities. For many years, LNG facilities were designed to meet the requirements of NFPA 59A. This was periodically revised and updated by its advisory committee which included representatives of the gas industry, insurance companies, federal agencies, manufacturers and consulting firms. NFPA 59A was intended to be a minimum standard that would provide a basis for safe design of LNG peak shaving plants. Recently it has been amplified to include some additional requirements for import terminals. In a number of respects, the NFPA 59A Code is more stringent than codes covering the construction of facilities for a wide range of flammable and/or toxic hazardous materials.

A few state and local authorities as well as Fire Brigades with jurisdiction over LNG facilities adopted regulations which duplicated or amplified the requirements of NFPA 59A.

In the early 70's, public concern began to be voiced about LNG safety. However, it is somewhat ironic that the extreme public and regulatory concern about LNG safety arose in the aftermath of a tragic accident in 1972 on Staten Island, New York. This accident involved 40 construction workers who were making repairs on the inside of an empty LNG tank when ignition of flammable insulation in the tank
occurred. While the accident did not compromise public safety, it nevertheless greatly amplified public and political concerns about LNG.

In response to public concerns, regulatory activity began to increase. The Office of Pipeline Safety (now part of the Materials Transportation Bureau - MTB) in the U.S. Department of Transportation (DOT) has responsibility for LNG Facilities under the Natural Gas Pipeline Safety Act of 1968. In October 1972, DOT adopted NFPA 59A (1971 edition) as an interim federal standard and started to develop their own regulations.

In February 1979, MTB published a notice of proposed rulemaking and later published final rules. The rules relating to sitting, design and construction were promulgated on January 30, 1980 with existing facilities "grandfathered" unless they are significantly altered by increasing the storage capacity or by relocation.

New rules covering operations, maintenance and security of LNG facilities were enacted on October 23, 1980 and are applicable to both new and existing facilities. An implementation period is allowed for existing facilities.

The rules for construction of new facilities are so stringent that the industry has virtually cancelled plans for new construction, although the existing facilities continue to operate.
Other examples can be given. In transmission pipelines, iron pipe failure due to corrosion became more frequent as pipelines aged. Federal standards for cathodic protection and other corrosion control measures were enacted. The incidence of corrosion failures dropped significantly.

Standards will continue to evolve as analysis of occurrence of accidents indicate weaknesses in present requirements. An accident at the Cove Point, Maryland LNG import terminal in October 1979 uncovered a deficiency in the design of certain seals in electrical systems. Changes are now being made in the NFPA Codes and the National Electric Code to correct the deficiency.

Only a few major accidents have related to the extensive worldwide operations involving LPG energy storage and transportation - the most serious involved rail or road transport accidents. The U.S. Department of Transportation is now requiring the use of head shields on LPG rail tank cars to prevent coupler punctures during derailments. In addition, LPG rail cars are now being coated with a fire protective material to reduce the likelihood of "BLEVE" type accidents. The "BLEVE" accident usually results after an LPG tank has been immersed in a fire for several minutes or more.

Following a refrigerated LPG tank failure in Qatar, a careful investigation of the accident was conducted and several changes were made in the draft British Institute of Petroleum Code to which the tank was built. One of the changes brought metallurgical testing requirements into
conformance to the somewhat more stringent U.S. API and ASTM Codes. In addition, the British code now requires 100% hydrostatic testing of a refrigerated LPG storage tank before it is commissioned. This latter requirement is more stringent than the API Code requirement, which allows a partial hydrostatic test if the tank foundation (as designed for normal operating stress loadings) cannot take the loadings for a 100% hydrostatic test. The API code is currently being revised for LPG.

In the recent past, Shell International has proposed a double integrity containment system for refrigerated LPG and LNG storage tanks in areas where a serious tank problem has potential to impact public safety. The secondary containment system would be designed to withstand catastrophic failure of the primary container.

There are, however, differences of opinions within the industry as to the need for designing the storage system to withstand a catastrophic failure of the primary containment vessel. This controversy is centered on the ability to be assured that the material of the primary containment vessel has crack arrest properties, which would preclude the possibility of the vessel unzipping. Work on the metallurgical properties of low temperature materials is currently being conducted in order to resolve these questions.

While it is rare that regulations ever are made less stringent, it is clear that many of the present U.S. regu-
lations covering LNG are inconsistent - in terms of actual hazards - with rules for LPG and other hazardous materials.

5. Natural Gases and Liquids Standards

In the United States, The Natural Gas Pipeline Safety Act was enacted in 1968 and applies to "pipeline facilities and the transportation of gas." The regulations presented in 49 CFR 190-193 were issued under the authority of this act and address pipeline safety program procedures, transportation of natural and other gas by pipeline: reports of leaks, transportation of natural and other gas by pipeline: minimum federal safety standards and liquefied natural gas facilities: federal safety standards, respectively. A notable exception in that the regulation in Parts 190 and 192 as applicable to "offshore gas gathering lines" were issued under the Hazardous Materials Transportation Act of 1979. The Hazardous Liquid Pipeline Safety Act was enacted in 1979 and based on that, 99 CFR 195 was promulgated. It addresses the transportation of hazardous liquids by pipeline.

The Pipeline Safety Program Procedures, as stated in 49 CFR 190, prescribes the techniques employed by the Materials Transportation Bureau and the Office of Operations and Enforcement in exercising their duties regarding pipeline safety. Enforcement is addressed in detail, with both civil and criminal penalties specified.

The reporting of natural and other gas leaks is detailed in 49 CFR 191. The conditions under which leaks must be
reported, e.g. they caused a death or a personal injury requiring hospitalization, are presented as are the reporting procedures to be followed. The latter includes telephonic notice of leaks, incident reports and annual reports.

The federal safety standards for the transportation of natural and other gas by pipeline are found in 49 CFR 192. The regulations, which are numerous and detailed, address materials; pipe design; design of pipeline components; welding of steel in pipelines; joining of materials other than by welding; general construction requirements for transmission lines; customer meters, service regulators and service lines; requirements for corrosion control; test requirements; uprating; operations; and maintenance. The materials specifications chapter is of particular interest as the use of plastic pipe is becoming more widespread. This is specifically addressed in Section 192.59. Subpart I is also of great importance as it presents the requirements for the protection of metallic pipelines from external, internal and atmospheric corrosion. There are detailed specifications for protective coatings, cathodic protection and monitoring.

The federal safety standards for liquefied natural gas facilities are presented in 49 CFR 193. Specific requirements include siting; design of materials, components, buildings, impoundment areas, storage tanks and transfer systems; construction; equipment; operations; maintenance; personnel qualifications and training; fire protection and security. Siting requirements detail protection from thermal radiation.
and flammable vapor-gas dispersion. It should be noted that the applicability of these standards is specified as a function of the date of construction or major alternatives.

The transportation of hazardous liquids by pipeline is addressed in 49 CFR 195. There are specific subparts for accident reporting; design requirements; construction; hydrostatic testing; and operation and maintenance. A "hazardous liquid" is defined to mean petroleum, petroleum products and anhydrous ammonia.

The regulations found in 49 CFR 192 and 193 contain numerous references to industry standards. These standards have been formulated by the American Concrete Institute, the American Gas Association, the American National Standards Institute, the American Petroleum Institute, the American Society of Mechanical Engineers, the American Society for Testing and Materials, the International Conference of Building Officials, the Manufacturers Standardization Society of the Value and Fitting Industry and the National Fire Protection Association. Examples include API Specification SA "API Specification for Casing, Tubing and Drill Pipe" (1979) and NFPA Standard 30 "Flammable and Combustible Liquids Code" (1977).

There are a variety of pipeline safety regulations in countries other than the United States. For example, Canada has gas pipeline regulations which were promulgated in the wake of the enactment of the National Energy Board Act. Different parts of these regulations are entitled design and installation; construction activities; field pressure
testing; operation, maintenance, repair and abandonment of pipelines; and accident reporting.

Detailed industry standards have been generated by the Canadian Standards Association for both gas pipeline systems and liquefied natural gas. The former, which is Z184, addresses materials and equipment; welding; pipeline system components and fabrication details; design, installation and testing; plastic pipe for use in pipelines operating at a pressure of 700 kPa or less; external corrosion control; operating and maintenance procedures; and "miscellaneous" subjects such as odorization and liquefied petroleum gas. Liquefied natural gas requirements are presented in Z276. With subparts entitled general plant considerations; process systems; stationary LNG storage containers; vaporization facilities; piping systems and components; instrumentation and electrical services; transfer of LNG and refrigerants; and fire protection, safety and security, this standard is very similar in content to NFPA 59A.

The various standards show some differences in philosophy. For example, the IP. Code (Part 6) gives a method for determining an isolation distance between pipelines and existing inhabited buildings. It states that the distance can be reduced if more conservative design factors are used in determining the pipe wall thickness, but does not give particular requirements. On the other hand ANSI B31.8 describes a class location concept which specifies a means
of adjusting the pipeline design factor to suit building densities - the higher the density, the lower the design factor and hence the thicker the pipe wall. With this concept, no isolation distance is required.

Other areas of some differences in the pipeline codes include depth of burial, test pressure, location of valves, monitoring for leakage and marking requirements.

The U.S. has developed a very comprehensive set of regulations covering the design of tanks used in hazardous material transportation. These regulations take into account the relative hazard of various materials that might be transported and include tank specifications that will minimize transportation risks for each category of hazardous material.

For hydrocarbon fuels, the requirements are separated into those for pressure tanks carrying liquefied flammable gases (including LPG) and non-pressure tanks for flammable liquids with vapor pressures below 40 psia at 100°F. Of concern is tank design, expansion of liquid due to ambient pressure changes, vulnerability of fittings (bottom vs top piping connection), and fire exposure. These regulations are contained in 49 CFR Section 179.

In response to past BLEVE accidents, LPG tanks, for example, have to have thermal protection systems so they can withstand a pool fire for 100 minutes or a torch fire for 30 minutes, with no release of contents except through safety release valves. The type of pool and torch fires are specified in detail through specification of simulated
fires used to test thermal protection systems.

Crash worthiness is also considered with requirements for a tank head resistance system which must be designed to withstand a specified test impact by a ram car. Coupler vertical restraint systems are also required.

Use of LPG as an automotive fuel is limited in the U.S. (mostly farm vehicles, fork lift trucks; etc). NFPA 58 is generally used as a basis for the design of distribution systems, transfer systems, and smaller containers, and for the installation of LP gas systems on vehicles.

One of the concerns with LPG is that it is heavier than air and can accumulate in low spots. Also, if confined it may cause an explosion. In some urban places in the U.S., LPG tank trucks are prohibited from going through tunnels. However, there are many equally congested areas that accept the risk of such travel.

Many countries are now pondering the U.S. DOT LNG regulations. Portions of these new regulations - notably the flammable vapor exclusion zone and seismic and wind design - exceed past practice and present industry and regulatory practice for a variety of other hazardous materials. For example, in Japan, LNG facilities are now designed for flammable vapor dispersion buffer zones, but a 3-minute design spill is used (versus 10 minutes in DOT)
and vapors at the property must be diluted to a 5% concentration (versus 2.5% in DOT). To my knowledge, no major facility has yet been built or planned in the U.S. which fully meets the new DOT LNG regulations.

There are several British codes and standards which govern LPG operations. In 1973, the Department of Employment published Health and Safety at Work (HSW)-30 entitled, "The Storage of Liquefied Petroleum Gas at Factories." It specifically addresses precautions for storage and handling, ignition source control and fire protection. In 1970, "Liquefied Flammable Gases Storage and Handling - Engineering Codes and Regulations" was published by Imperial Chemical Ltd. and the Royal Society for The Prevention of Accidents (ROSPA). Addressed in these regulations are safety distances for location and spacing, ignition source control, pressure relief design, fire protection and road, rail and ship tanker loading and unloading. The Liquefied Petroleum Gas Safety Code, which is Part 9 of the Institute of Petroleum Model Code of Safe Practice in The Petroleum Industry, was jointly prepared by The Institute of Petroleum, The Institution of Gas Engineers and The Liquefied Petroleum Gas Industry Technical Committee. First published in 1967, it was last revised in 1975. This code specifies storage tank design and location, fire protection and rail tank car design. Other British codes and standards which pertain to LPG include "Safety Recommendation IGE/SR/6-Liquefied Petroleum Gases" published by The Institute of Gas Engineers and the "Code and Practice for The Storage of Liquefied Petroleum
Gas at Fixed Installations" published by Home Office.

The Standards Association of Australia has published "Standard No. 1596- Rules for The Storage and Handling of Liquefied Petroleum Gases." First published in 1973, it was last reprinted in 1978. The detailed regulations which are specified in this standard include requirements for both above-ground and underground storage tanks, rail tank cars and liquid transfer.

The New Zealand Fire Service published an information guide entitled, "The Safe Handling of Liquefied Petroleum Gas and Engineering Procedures." It includes information on purging and ventilation, multi-mode transportation, cooling water application, container failures, the BLEVE (Boiling Liquid Expanding Vapor Explosion), operational procedures, fire prevention and fire protection.

6. Factors in Establishing Safety Standards.

After considering the problems and deficiencies in previous attempts to assess economic impacts and benefits of new or proposed regulations, the question of how this may better be done arises. This is a difficult problem and one that is properly in the province of the regulatory agencies. It seems reasonable that new regulations should be developed with due regard to the fact that consumers are paying the costs of making risks acceptably low to abutters of hazardous material facilities. We cannot afford zero risk and, in fact, do not require zero risk for a wide range of activities.
and exposures which we accept routinely. The public is now becoming increasingly aware of a whole spectrum of risks produced by our industrial sector including problems with pollutants, carcinogens, hazardous waste disposal, toxic and flammable materials handling, etc. It will be costly to upgrade public safety, and we should spend our money wisely. I suggest that a decision maker might attempt to assess present levels (including ranges) of risks to which the public is exposed. Presumably the public is concerned that these levels are not adequate in a number of areas. Thus, as a society, we should attempt to identify risks which presently are significantly higher than the accepted range and attempt to reduce such risks through corrective measures which might include regulatory or industry actions, provision of incentives or penalties, etc. In addition, our standard of living and economic status is high enough so we can probably afford to push general levels of safety higher than they are at present.

In our opinion, it is a mistake to attempt to develop regulations on the premise that there is some remote potential for catastrophe, if the probability of the remote event is not also considered. Also, in focussing on the extremely rare event, control of some lesser but more likely risks may be overlooked. We are very aware of the large uncertainties in setting probability levels for very rare events. Nevertheless, such estimates - along with estimates of uncertainties - are useful tools in the decision process.
Whether they formally quantify probabilities or not, the regulatory decision makers are already estimating risks intuitively when maximum credible or design accidents are established. Only by comparing risks can decision makers determine whether a need for more stringent measures exists. If the risk levels seem to be too high, risk reduction measures and costs should be evaluated. Conversely, it is hoped that regulatory decision makers will also have the courage to amend, or adopt in modified form, regulations which are excessively stringent and increase consumer costs unnecessarily.

Since the existing discrepancies in regulations are probably due mostly to perceptions of risk rather than to true relative hazards, both the public and its representatives will have to become more knowledgeable about hazardous material risks. This is difficult to do without alarming people about hazards of which they aren't aware, but probably will be required if society is to find a reasonable balance between safety and costs to consumers.

Further, it seems that different localities or countries may have different existing background risks and different attitudes toward acceptable safety. At the most local level, there is the danger that each town may ban all hazardous facilities but hope that they will be located nearby so economic benefits may be enjoyed. Thus, the approach of decision making in a national or regional forum appears to be the best solution.
A Model for Evaluation of Natural Gas Development Strategies

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ABSTRACT

An increasing number of developing countries are seeking ways to develop their indigenous reserves of natural gas and thereby reduce reliance on imported oil as well as noncommercial fuels. In order to assist in these efforts, Bechtel has developed a computer-based gas pricing model. This model is the result of extensive experience in gas development projects and we believe the model will be a useful tool in developing countries for the following reasons:

- It provides a consistent framework for assessing the economic and financial impacts of a gas project, as countries seek external funding.
- It can be used as a planning tool to evaluate alternate gas pricing strategies.
- It can generate results quickly and test for sensitivity, once the required inputs are prepared.

This paper discusses the many problems and issues related to gas pricing and describes the Bechtel Natural Gas Pricing Model. The system examined consists of a gas field, gathering lines, a separation plant, and pipeline transmission system to the users' gates. The paper explains the process followed by a planner in order to size the system, estimate capital and operating costs, and price the products.

INTRODUCTION

A number of developing countries, hurt by the rapid increase in imported oil costs since 1973, are interested in developing their natural gas resources for domestic consumption. Before this can be done, they need to examine the effects of gas pricing upon both the rate of economic development and how the gas is used. Development of a pricing policy is complex and involves several major problems.

PROBLEMS IN SETTING GAS PRICES

- NO INTERNATIONAL MARKET
- POLITICAL PRESSURES TO SUBSIDIZE PRICES
- NEED TO PAY BACK DEVELOPMENT LOANS
- NEED TO ATTRACT PRIVATE SECTOR INVESTMENT IN EXPLORATION
First, there is no well defined international market for natural gas, as there is for oil. Export facilities for liquefaction and shipment as LNG or conversion to methanol are feasible in some cases, but the capital costs are high and the market limited. Without long-term purchase contracts, funding is unlikely.

Secondly, the governments in these countries are under considerable pressure to use the gas internally and to price it low enough to encourage economic growth through lower costs of fuel and electricity.

Thirdly, they need to set prices high enough to provide sufficient return on investment to the international lending institutions who are the major funders of gas development in many cases.

Fourthly, if they have encouraged private oil exploration and development companies to invest in gas, they must guarantee an adequate return on the investment.

I will attempt to examine these problems as they relate to the establishment of a gas pricing policy and then describe a model we have developed at Bechtel. The model is not intended to solve the problems but it does provide an analytical tool for the policy-makers and economists, allowing them to see the implications of various pricing strategies and gas development options.

CONSIDERATIONS IN GAS PRICING

National Objectives

Natural gas is a costly fuel to store, convey by pipeline, and distribute to consumers. It is very unlikely that more than one production and pipelining company would be active within a region; the capital investment is just too high. Consequently, the government must take a hand in empowering a single gas company, whether it be private or state-owned, to operate in a region and to regulate the price charged. We cannot assume that a free market will establish the price of gas; this just won’t work in a monopoly type enterprise.

OBJECTIVES IN SETTING GAS PRICES

- ACHIEVE RETURN ON INVESTMENT
- ENCOURAGE INDUSTRIAL GROWTH
- HOLD DOWN ELECTRIC POWER RATES
- REDUCE OIL CONSUMPTION
- REDUCE AIR POLLUTION
- CREATE FUNDS FOR FUTURE DEVELOPMENT
If the government must set the price of gas, what objectives should it consider?

- First, the gas company should make a reasonable return on investment. (We'll talk more about this form of regulation when we consider the United States experience in gas industry regulation.)
- Second, the price of gas should encourage, not inhibit, industrial growth.
- Third, particularly in the Third World where electrification is a national objective, the gas should be priced to the electric power industry at a level that holds down power costs to industry.
- Fourth, indigenous gas should be sold at a price that encourages its substitution for oil products, particularly if this oil must be imported.
- Fifth, in heavily industrialized regions, substituting gas for other fuels such as coal, wood, or oil may help reduce air pollution.
- Sixth, the price of gas should be sufficient to provide funds for future development, either of additional gas supplies or of alternative fuels when the gas resource is depleted.

Pricing an Exhaustible Resource

The Club of Rome, economist Hotelling, and other later theorists have well established the fact that pricing of exhaustible resources such as oil and gas cannot be expected to conform to the simple supply-demand mechanisms that Adam Smith taught us all to revere. A third factor, time, has to be considered, for time and demand affect both supply and cost.

**PRICING AN EXHAUSTIBLE RESOURCE**

- PRODUCE NOW OR SAVE FOR LATER?
- OPPORTUNITY COST OF ALTERNATIVE GAS USE
- MARGINAL COST OF INCREMENTAL PRODUCTION

Should a gas field be produced now when gas can be sold for say $3.30 per Mcf (70 percent of medium fuel oil), or should it be shut in for 10 years and then produced and priced at the same ratio to fuel oil price if fuel oil prices escalate 1 percent per year in real terms?

Will the current price provide enough netback at the well (return on investment in exploration and development) to 1) pay off these costs and 2) allow funds to be set aside for drilling additional wells or to develop alternative energy resources (coal, hydro, geothermal) when the gas resources are totally exhausted?
These questions are peculiar to an exhaustible resource such as gas. As the resource is depleted, we can expect the price to increase and the demand to decline, as alternative fuels, once thought too costly, become economically feasible.

Another concept that needs to be considered in setting a long-term pricing policy for natural gas is its "opportunity cost." Rather than only equating gas value with the use under consideration (say, as fuel to the power industry), what is the lost income or benefit that could have been obtained if the gas had been used in some higher valued alternative process? The income that is foregone by dedicating the gas to power generation, can be viewed as its true value. The true value of gas might be higher if it were used in the fertilizer industry, where additional urea production for export could generate major export earnings. It could be used in the LNG industry, where values in excess of $4.50 per million Btu's could be obtained. This leads to questions such as, can more revenue be generated by importing Bunker C oil for power generation and dedicating the indigenous gas resource to an industry that generates foreign exchange?

Marginal costing is another concept that deserves mention. Once a gas field is placed in production and prices are set at a level sufficient to meet both the fixed costs (debt retirement) and operating expenses, each incremental increase in gas production need only be priced at a level sufficient to meet the marginal costs of that increase. This is because most fixed costs have already been met. Thus some flexibility is available in pricing additional gas, and perhaps revenue can be set aside for future development of higher-cost fuel replacements when the gas reserves are depleted.

These concepts — exhaustible resource pricing, opportunity costs, and marginal costing — are mentioned here to illustrate the ideas that must be considered in setting a gas pricing policy and to warn against making any gas price too rigid. On the other hand, a gas price that varies widely over time as pricing policy changes can hinder industrial development; investors will not be able to rely on a consistent fuel cost.

**MINIMAL CRITERIA IN GAS PRICING**

- MEET FIXED AND VARIABLE COSTS
- PRICE GAS FROM SYSTEM EXPANSIONS AT LEAST AT MARGINAL COSTS
- GENERATE RETURNS SUFFICIENT TO MEET GUARANTEES TO PARTNERS IN EXPLORATION
- SET ASIDE REVENUE FOR REPLACEMENT OF EXHAUSTED RESOURCES
Four Minimum Pricing Criteria

Given all these considerations, what basic criteria can be given for the policy-maker? We can think of four:

- **Criteria 1:** The price must meet all fixed costs as well as variable costs related to gas field development and production and pipeline operation.

- **Criteria 2:** Expansions to the system must be paid for by pricing the additional gas at least at the marginal cost of increasing the system capacity.

- **Criteria 3:** The return on investment must at least cover any government commitment to its partners in gas field development and production.

- **Criteria 4:** Funds from gas sales must be set aside to finance secondary recovery, develop either new gas fields to sustain supply, or develop alternative fuels should the gas resources be fully depleted.

No gas pricing policy can be sustained in the long term that does not meet these criteria. I could add a fifth pricing criteria as well, but it is not imperative, just advisable:

- **Criteria 5:** Gas sales cannot be maintained at a price significantly below opportunity cost without damage to the gas production industry.

The experience of the United States is an example of this point.

How Not to Set Gas Prices

During the past 45 years the United States has experienced several major changes in gas pricing policy which provide a good lesson in how not to price an exhaustible resource. Government involvement began with the Natural Gas Act in 1938 to regulate interstate gas transmission companies. These gas transmission companies were allowed to recover their costs plus a fair return on their investment in pipelines and rights-of-way. This “fair return,” set by the government, did not include costs of gas production until 1960. The regulatory bureaucracy moved very slowly in reviewing individual pricing cases, and this regulatory lag held down gas prices at the wellhead to 10 to 15 cents per million Btu’s.

Prices increased during the 1960s and reached 30 cents by 1974; at that time the OPEC price increases forced a revision to 50 cents for newly discovered gas, less than one third the price of crude oil at the time. By 1978, crude oil was priced at $13.00 per barrel ($2.17 per million Btu’s) while new gas was controlled at $1.00 per million Btu’s at the wellhead.

The comparison here between oil and gas prices is not intended to suggest that parity should be the goal. Rather, it serves to demonstrate the unrealistically low prices of gas in the 1960s and 1970s. With relatively low returns likely on investment in new gas production, exploration activity decreased and U.S. gas reserves began to decline in 1967. As fuel oil costs escalated, many domestic and industrial users switched to cheap gas, causing a shortage that could not be easily corrected at then current gas prices.

By 1973, the Federal Power Commission decided to set gas at 85 percent of the thermal equivalent price of oil. The OPEC crisis quadrupled oil prices shortly thereafter and the FPC decision was rendered meaningless. But, a linkage between competing fuels had been established as a part of the rate-making process.
After the OPEC oil price increase of 1973, the FPC was slow to approve future increases in the price of gas, even though it had acknowledged the concept of opportunity cost in its pricing policies. By 1975, severe gas shortages began to occur and during the winter of 1976-77, gas shortfalls forced closure of many factories in the U.S. It was clear to U.S. government officials that regulating the price of natural gas in the U.S. was an administrative failure and had led to economic dislocations. Alarmed by these economic dislocations, the U.S. Congress passed the Natural Gas Policy Act of 1978 (NGPA). The NGPA fundamentally altered the manner in which natural gas prices were set in the U.S. It placed existing and new supplies of natural gas into eight separate categories and allowed different price structures for each category. It also provided for the phased deregulation of natural gas prices by 1985.

Under the NGPA, gas prices were to be set by vintage of the gas, with gas from deep wells not controlled at all. A huge disparity in gas prices was created and continues to plague the U.S. market. Demand increased for the price-controlled gas after the 1979 jump in oil prices, and a bidding war erupted over the decontrolled deep gas. This raised the price of the old gas until, by 1982, average residential prices were $5.47 per million Btu and industrial users faced $4 to $5. At the same time, the oil market softened until residual fuel oils began to look more attractive than costly gas. Industrial gas consumption decreased 18 percent from 1980 to 1982. Now, with lower demand for gas at higher costs, we have a surplus of gas producers and transmission systems. A reduced number of users must still pay the fixed costs of this system, further increasing prices.

**U.S. EXPERIENCE IN GAS PRICE REGULATION**

- Low prices caused demand to exceed supply
- Insufficient return on investment did not allow for expansion of production capacity
- Rate-of-return type price setting is not effective for an exhaustible resource

The history of natural gas pricing in the U.S. illustrates the pervasive influence of the price system on resource allocation decisions. When gas is under-priced relative to other fuels, as in the 1960s, demand will increase beyond supply. Furthermore, the low price will not allow the gas industry to make the necessary investments in new gas production capacity to meet growth in demand.
The rate-of-return on investment methodology is not effective for pricing an exhaustible resource, since it does not recognize the need for prices to rise as the resource is depleted. Only such a rise will encourage production of more expensive alternative energy sources.

This example is not intended to prove that all regulation of gas price is wrong. Some regulation may always be necessary with an exhaustible resource to ensure that the needs of the future are considered far enough in advance of shortage. Prices must be allowed to increase even if production costs remain stable, in order to encourage the development of higher cost fields. Regulation must be done by those with an understanding of the economic forces at work and who are sufficiently insulated from short term political pressures to avoid erratic price changes or excessive reaction to short-term economic trends.

In many developing countries, gas pricing has been determined by political considerations unrelated to the economic factors mentioned in this paper. Low electric utility rates, to encourage industrial growth and electrification of villages at affordable prices, have resulted in gas also being priced far below opportunity cost. In some countries, export industries have also received a special low rate while domestic industries bear the burden of higher gas costs. Where a country has export income from gas, LNG, or oil, these low gas prices may be seen as a subsidy to the domestic economy. Where oil and gas exports are relatively large, such a subsidy may be tolerated for some years before an adjustment is necessary. If there are alternative gas uses (LNG, methanol, fertilizers for export, petrochemicals) that could provide a higher price for gas, continued low price setting is a costly subsidy and represents a loss to the national economy.

BECHTEL'S GAS PRICING MODEL

Our purpose is not to develop the perfect solution to your gas pricing problems, for we are convinced that in each country and for each period in its economic development, the solutions to these problems will vary. Economists and energy policy-makers will need to predict the impacts of their proposed energy prices upon the economy before a final price decision is made. However, economic forces can be better understood with a pricing model that allows capital costs of new delivery systems and gas field expansions to be estimated quickly and dependably. Such a model can then predict the price that will allow a system to operate profitably with sufficient return on investment to ensure that funds will be available when needed to invest in new capacity.

Bechtel has developed a model that we hope will be of value to energy planners in developing countries where sound policy-making in the early years of gas development will ensure a healthy and economically expanding industry. The model is intended for use on a personnel computer such as the IBM PC.

The Bechtel Natural Gas Pricing Model (BNGPM) is designed to help planners estimate the delivered cost of natural gas from proposed supply systems to potential industrial users. It provides the planner with a framework for:

- Sizing the natural gas supply system
- Estimating capital and operating costs
- Pricing products
The system consists of a gas field, gathering lines, a separation plant, and pipeline transmission system to the users' gates. The model permits a transmission network with up to five segments. The system is illustrated in the sketch below.

The model determines the rate of return permitted by a specified average price for the process gas and any by-product condensate (natural gas liquids) recovered at the separation plant. Alternatively, the model can be used to determine the average price over time required to achieve a desired rate of return.
The model consists of four basic functional modules as illustrated in the diagram:

- Demand module
- Field module
- Transmission module
- Economic evaluation module

In a typical interactive session with the model, planners will follow the sequence indicated.

**Demand Module**

The demand module provides a worksheet for planners to specify the average and peak demands of potential users over time. This module computes the aggregate average and peak demands, which are used in the other three modules.

Industrial demands may be specified in terms of power plant output kilowatt hours, fertilizer production, or cement plant output. The module converts these into gas demands. System peak serves as the design level for separators and pipelines.

**Field Module**

The field module generates a well drilling and investment schedule after the planner enters characteristics of the gas field, well drilling rates and likely depths, and likely drilling success rates.

The planner then enters gas condition and condensate data, as well as separator plant cost parameters, to allow the module to estimate costs of the field separator plant. The recovered condensate is priced as a source of revenue to the gas system at prices and escalation rates set by the program.

**Transmission Module**

The dry gas pressure and design flow rate serve as input data to the transmission module. The model has programs for economic pipe sizing and compressor station design and cost estimating to allow an iterative analysis. The pipeline design worksheet calculates maximum expected operating pressure, maximum allowable operating pressure, and compression ratios in each of up to five pipe segments, based on pipeline configuration and flow data provided by the planner. The planner can trade off pipe diameter, wall thickness, number of compression stations, and exit pressure, in order to maintain peak operating pressure below the maximum allowed at a desired compression ratio. Thus, the pipeline design worksheet provides the flexibility to:

- Receive input data on a previously designed pipeline network
- Provide design checks on a previously designed network
- Help the planner design a functionally feasible pipeline network from scratch

This transmission module calculates requirements for steel, compressor stations, and fuel for operations and provides a capital and operating cost summary for use in the economic evaluation module.
Economic Evaluation Module

This module gives the planner the option to calculate either:

- The internal rate of return, based on specified average gas prices over time for the delivered gas and by-product liquids
- The average prices over time of delivered gas and by-product liquids, based on a specified desired internal rate of return

The module also provides the planner with an additional option. The entire system can be analyzed as though it were owned by a single entity, or the production facilities (wells and flow lines) can be analyzed separately from the rest of the system, as though they were owned by a second entity with its own rate of return or average price requirements. In this two-entity case, it is assumed that the production company sells the raw gas to the owner of the gathering, processing and pipeline facilities. The sales price of the raw gas is determined as described above, either by setting it explicitly, or by calculating it based on a desired rate of return.

Pro forma balance sheets for both the gas processing and transmission company and the production company are produced showing all income and costs over a 20-year life of the gas system.

We at Bechtel will be using this gas pricing model as we work with several countries on their energy problems during 1984; we will probably be expanding and refining it as we become more aware of the needs of these countries in dealing with their energy problems and pricing policies.

We are most eager to hear from any of you concerning your energy needs, comments on our model, or suggestions for improvements. And we hope that the Bechtel Natural Gas Pricing Model can be of use to you all.
ELEVEN YEARS OPERATING EXPERIENCE

AT BLNG

H. Joubert
Manager Brunei LNG
In BLNG natural gas produced from oil associated wells and gaswells offshore in Brunei is converted into liquefied natural gas. Gas demand in Brunei is rather low. Gas is used to generate electricity for the State, for domestic use either in the form of natural gas or as LPG and as reinjection gas into oil wells to increase oil recovery. The gas potential of Brunei and the neighbouring States of Sarawak, Sabah and Kalimantan is far in excess of total demand in these areas. Consequently markets outside of these areas had to be found to develop the natural gas resources of the State of Brunei. A market for the Bruneian gas was found in Japan, and the gas liquefaction route was selected in 1968 as the most commercial and technically most attractive route to develop the natural gas resources of Brunei. The dominating factor governing the gas supply agreement between parties producing LNG in Brunei and parties buying and marketing LNG in Japan was the large capital investment required for the construction of the liquefaction facilities, the transportation facilities (LNG ships) as well as for the construction of the LNG receiving terminals in Japan. In view of these investments a long term supply agreement was concluded covering a period of twenty years for the delivery of 5.2 million tons of LNG per annum emphasising reliability and continuity of supply with LNG pricing structure following the BTU equivalent value of crude oil supplied in Japan. From this agreement it must be concluded that BLNG operations require a high degree of reliability and continuity of supply in view of the large capital investments involved.

Brief description of BLNG operating facilities (see slide 1) -

Gas from a large number of production wells offshore is transported by pipeline directly into the liquefaction units in BLNG, following initial drying offshore. Before liquefaction of the gas it is necessary to remove acid components, mainly carbon dioxide (CO₂) and hydrogen sulfide (H₂S) from the natural gas to prevent freezing and corrosion. This removal is carried out by extraction in sulfinol units.
A further removal of water and heavy hydrocarbons is required to prevent freezing out of these components in the liquefaction unit. The gas is consequently cooled and liquefied in the main cryogenic heat-exchanger where refrigeration is achieved through expanding and evaporating of a multi-component refrigerant. The liquefied natural gas is stored at temperatures of -163°C and shipped to Japan.

The Brunei LNG production facilities consist of five identical liquefaction units, each with a design capacity of 1.2 million tons of LNG per annum. The energy, power required to operate these facilities is supplied by eleven high pressure steamboilers with a total steamraising capacity of 2200 tons/hour and by four generators with in total 40 Mw electricity generating capacity.

Following this introduction into the Brunei LNG operating facilities I would now like to highlight BLNG's operating philosophy and operating experience in the last eleven years.

The operating philosophy is clearly governed by the factors as laid down in the supply agreement namely: reliability and continuity of supply. Based on these two commitments we have established in Brunei LNG three clear priorities for operating the plant (see slide 3). Number 1 is safety, number 2 reliability and number 3 efficiency. Placing of efficiency as number 3 should in no way be seen as downgrading of its importance. Continuous efforts are exercised to improve plant efficiency, however, in the drive for greater efficiency important concerns for safety and reliability will be overriding.

Safety

Technical integrity and personal safety aspects are key factors during the design stage of industrial complexes such as LNG plants. Some major factors considered during design with respect to safety are material selection, equipment selection, plant lay-out, safeguarding systems and personal protection systems. A safe operation will improve plant reliability and efficiency. Management of safety in a LNG plant is basically not different from that in any other industrial processing plant.
The main emphasis has to be put on maintaining a basic awareness of safety in all personnel and the appreciation of all for the need for rigorous safety procedures.

Maintaining of safety awareness in BLNG is pursued through review of safety procedures at regular intervals, conduction of safety audits, safety promotion schemes and a regular schedule of management Safety Working Committee and Company Representative Safety meetings.

See slide 4: in Brunei LNG there have occurred ten lost time accidents during 9 million manhours worked since plant start up in 1972.

Reliability is the next important operational priority (see slide 5).

The firm contract commitments for the supply of LNG for twenty years, the dedicated nature where disruption of supply could create serious problems for the utility companies in Japan, and the large capital investments make a very high reliability a pre-requisite for operating a LNG plant.

In order to achieve a high degree of reliability there have a number of important consideration to bear in mind (see slide 6).

As in the case of safety it is essential that the plant should have a sound basic design.

Secondly great care must be taken with respect to quality control during construction phase of the plant. In actual operation the main objective is to stay ahead of problems.

It is therefore important to have a good plant information system highlighting reliability performance. In BLNG the plant information system together with equipment monitoring systems have given management and staff the required support in anticipating operational problems. This is particularly the case in view of the fact that large numbers of equipment are identical. For example, there are 9 identical waste heat boilers, 15 identical main turbines and 34 identical cooling towers.

Frequent starts and stops are the main cause of equipment failure.
Having accomplished this year 1500 consecutive cargoes since start up without ever failing to meet our supply commitment is without any doubt a major motivational drive in BLNG's daily operations (see slide 7, 8 and 9).

**Efficiency** (see slide 10)

Significant efficiency improvements have been achieved since start up. The ratio of fuel and losses (BTU's) over feed (BTU's) has been reduced by some 35 percent in 10 years.

This improvement has been achieved through:

1. A generally improved operation of the plant with fewer start ups and shutdowns, and more concern in optimising the general operation of the plant.
2. Improve heat-transfer, through improved cleaning of cooling water system.
   The biggest problems are rust, debris, bacterial sludge and the formation of zincphosphate.
3. Improvement of the efficiency of cooling towers.
4. Improvement of boiler efficiency to 97 percent.

While these improvements have been obtained at virtually no cost, further significant improvements have been obtained through modest capital expenditures:

5. Increase insurface area of propane condensors by 80 percent.
6. Installation of a compressor to recover gas lost when loading a tanker.
7. Recovery of defrost gas from liquefaction trains during start up and shutdown.
8. Replacement of the boiler economisers with units having finned tubes.
9. Installation of an on-line computerised process supervision system.

I have tried in a few words to highlight the issues which BLNG considers as essential in our day to day operations and I would like to thank you for your attention.
OPERATING PRIORITIES IN BRUNEI LNG

1. SAFETY
2. RELIABILITY
3. EFFICIENCY
THE IMPORTANCE OF RELIABILITY

1. Firm contract — 97% take or pay

2. Dedicated projects — few alternatives of supply

3. Highly capital intensive
REQUIREMENTS TO ACHIEVE HIGH RELIABILITY

1. Good basic design
2. Detailed checking during construction
3. Stay ahead of problems
   - on line checking
   - reliability performance reporting
4. Minimize plant upsets
## BRUNEI LNG LIMITED

### RELIABILITY

AND

### AVAILABILITY

OF

LIQUEFACTION TRAINS

AS A PERCENTAGE OF

5 TRAIN OPERATION

<table>
<thead>
<tr>
<th>Year</th>
<th>Scheduled Downtime</th>
<th>Unscheduled Downtime</th>
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BRUNEI LNG LIMITED

RELIABILITY

AND

AVAILABILITY

OF

BOILERS

AS A PERCENTAGE OF

11 BOILER OPERATION

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<tr>
<th>Year</th>
<th>SCHEDULED DOWNTIME</th>
<th>UNSCHEDULED DOWNTIME*</th>
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<tr>
<td>1977</td>
<td>6.0</td>
<td>13.6</td>
<td>80.4</td>
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</table>

* THE 1983 FIGURE OF 4.5% UNSCHEDULED DOWNTIME INCLUDES 0.16% OF FORCED DOWNTIME, MAINLY CAUSED BY MECHANICAL PROBLEMS ON BOILER FANS PLUS A FEW INSTRUMENTATION FAULTS.
BRUNEI LNG PROCESS FLOW SCHEME
BASIC UTILITIES SCHEME AT BRUNEI LNG
Improvement in efficiency at Brunei LNG comes from:

1. Optimized operation
2. Clean cooling water system
3. Lower cooling water temperatures
4. Improved boiler efficiency
5. Increasing surface area propane condensors
6. Recovery of loading boil off gas
7. Recovery of 'DEFROST' gas during start-up and shut-down of Liq. trains
8. Increasing surface area boiler economisers
9. Installation of computerised process supervision system
TIME/MANHOURS WORKED BETWEEN LOST TIME ACCIDENTS

MANHOURS WORKED
BY BLNG STAFF

DETAIL 1980:
12.5.80  2718000
27.6.80  99300
6.9.80   141000
THE INDONESIAN GAS UTILIZATION

by

NURANI MUDAYAT

Head, Natural Gas Processing & Transportation
Directorate General of Oil & Gas
INDONESIA

Thailand - US Natural Gas Utilization Symposium
Bangkok, 6 - 9 February 1984
DISTINGUISHED GUESTS,
LADIES AND GENTLEMEN:

ALLOW ME TO EXPRESS HERewith MY HIGHEST APPRECIATION
AND GRATITUDE FOR THE GREAT HONOUR AND OPPORTUNITY
RENDERED TO ME TO BE PRESENT AMONG YOU TO PARTICIPATE
IN THE THAI-U.S., NATURAL GAS UTILIZATION SYMPOSIUM
TO TALK ABOUT INDONESIA GAS UTILIZATION.

I FEEL HAPPY NOT ONLY BECAUSE I AM ABLE TO COME
BACK TO VISIT THE BEAUTIFUL CITY OF BANGKOK, BUT ALSO
BECAUSE I DO REALIZE HOW IMPORTANT THE TOPIC OF THE
DISCUSSION WE ARE GOING TO HAVE.

AS YOU KNOW INDONESIA IS ONE OF THE MOST POPULATED
COUNTRIES IN SOUTH EAST ASIA WITH MORE THAN 150 MILLION
INHABITANTS AND A POPULATION NUMBER EXPECTED TO REACH
THE MARK OF 200 MILLION AT THE TURN OF THE CENTURY.
INDONESIA HAS EXPERIENCED \ FAVOURABLE ECONOMIC GROWTH
PARTICULARLY SINCE THE BEGINING OF THE SEVENTIES.
DESPITE THE PRESENT SLOWDOWN IN EXPANSION, ECONOMIC
GROWTH RATE SHOULD REMAIN AMONG THE HIGHEST TO BE
REGISTERED IN THE WORLD IN THE NEXT COMING YEARS.

INDUSTRIAL SECTOR HAS TO A GROWING EXTENT CONTRIBUTED
TO THIS ECONOMIC EXPANSION OBSERVED IN THE RECENT PAST.
AT THE TIME BEING, INDUSTRIALISATION HAS BEEN MAINLY
ACHIEVED IN THREE WAYS:

- BUILDING OF A NETWORK OF MEDIUM AND LIGHT INDUSTRIES
DEVELOPMENT OF ENERGY-INTENSIVE BASIC INDUSTRIES SUCH AS STEEL WORKS, AMMONIA AND CEMENT PLANTS, ETC., THE PRODUCTION OF WHICH IS NOT FAR FROM MATCHING THE FAST RISING DEMAND OF THE DOMESTIC MARKET.

DEVELOPMENT OF LARGE EXPORT-ORIENTED PROJECTS CHIEFLY ILLUSTRATED BY THE LNG PLANTS.

SINCE ENERGY PLAYS A KEY ROLE IN THAT DEVELOPMENT A CLEAR AND COMPREHENSIVE POLICY HAD TO BE DEFINED. FOR THIS PURPOSE THE MAIN GUIDELINES OF INDONESIAN GOVERNMENT ARE:

- TO ACCELERATE THE DEVELOPMENT AND THE PRODUCTION OF ALL FORMS OF ENERGY BY INTENSIFYING EXPLORATION. IN PARTICULAR THE OIL AND GAS SECTOR AT LEAST MAINTAIN THE PRESENT LEVEL OF PRODUCTION AND, HOPEFULLY, INCREASE THAT LEVEL WHENEVER POSSIBLE,

- TO SUBSTITUTE THE OTHER SOURCES OF ENERGY FOR OIL IN THE EXISTING AS WELL AS IN THE PLANNED PLANTS, IN ORDER TO CONSERVE OIL FOR EXPORT MARKETS,

- TO TAKE MEASURE AIMING AT AN EFFECTIVE DOMESTIC CONSERVATION (FOR INSTANT THROUGH THE MINIMIZATION OF WASTAGE OF ASSOCIATED GAS STILL BEING FLARED) AND AT THE BEST USE OF SUITABLE FORM OF ENERGY FOR EACH GIVEN APPLICATION.

AS SHOWN IN TABLE -1 HERE PRESENTED THE RESULTS OF THIS ENERGY POLICY ALREADY APPLIED FOR SEVERAL YEARS IN INDONESIA CLEARLY APPEAR IN THE FIGURES OF THE DOMESTIC
DEMAND FOR THE DIFFERENT FORMS OF ENERGY, WHERE A FAIRLY LARGE PORTION OF OIL SHARE HAS BEEN SUBSTITUTED BY GAS.

FOR MEETING THIS ENERGY POLICY OUR COUNTRY IS ENDOWED WITH CONSIDERABLE FOSSIL RESOURCES, I.E. COAL, OIL AND GAS. SOME OF THESE RESOURCES HAVE BEEN IDENTIFIED WHEREAS THE CHANCES OF FURTHER AND SUBSTANTIAL DISCOVERIES ARE VERY HIGH. AS REGARDS GAS, THREE EXTRALARGE FIELDS HAVE ALREADY BEEN FOUND, SHOWN IN TABLE 1 A :

- IN NORTH SUMATRA (ARUN)
- IN EAST KALIMANTAN (BADAK)
- IN SOUTH CHINA SEA (NATUNA)

IN ADDITION SEVERAL OTHER ASSOCIATED AND NON-ASSOCIATED GAS FIELDS OF A MINOR IMPORTANCE HAVE BEEN DISCOVERED IN ALMOST ALL PARTS OF THE COUNTRY. IT IS NOW GENERALLY ASSUMED THAT GAS RESERVES ARE AT THE SAME LEVEL OR EVEN HIGHER (IN ENERGY - EQUIVALENT UNITS) THAN THOSE FOR OIL.

THIS GROWING ROLE OF GAS IN THE OVERALL ENERGY PICTURE IS ILLUSTRATED BY PRESENT CONSUMPTION FIGURES AND THOSE EXPECTED WITHIN THE NEAR FUTURE.

LET ME RECALL THAT INDONESIA ENJOYS A LONG EXPERIENCE IN GAS UTILIZATION AS TODAY THE STORY OF GAS PENETRATION IN THE DOMESTIC ENERGY MARKET IS ALREADY TWENTY YEARS OLD. THE FIRST LINE IN THE SOUTH SUMATRA GAS SYSTEM WAS IMPLEMENTED IN THE EARLY SIXTIES WHEN A DECISION WAS MADE
TO BUILD NEAR PALEMBANG AN AMMONIA-UREA PLANT (PUSRI I). THE FIRST DELIVERY FROM THE GAS LINE OCCURRED IN JANUARY 1964. THIS OCCASION MARKED THE FIRST COMMERCIAL UTILIZATION OF NATURAL GAS OUTSIDE THE PETROLEUM INDUSTRY. THUS, IN INDONESIA THE DOMESTIC GAS MARKET IS NOT A NEW CONCEPT AND THE MAIN INDUSTRIAL USERS ARE AWARE OF THE ADVANTAGES OFFERED BY GAS OVER ALTERNATIVE ENERGIES. FROM THAT TIME FURTHER GAS DISCOVERIES AS WELL AS NEEDS FROM SPECIFIC GAS CONSUMING INDUSTRIES (AMMONIA. STEEL, CEMENT) HAVE LED TO AN IMPORTANT CONTRIBUTION OF GAS INTO OUR ECONOMIC DEVELOPMENT.

ON THE EXPORT SCENE, FACILITIES FOR THE LIQUEFACTION OF NATURAL GAS WERE INAUGURATED AT BADAK IN EAST KALIMANTAN IN AUGUST 1977 AND AT ARUN IN NORTH SUMATRA IN SEPTEMBER 1978. EXPANSION OF TWO TRAINS EACH FOR BADAK AND ARUN HAS BEEN COMPLETED LAST YEAR. SHOULD ALSO BE MENTIONED GROWING EXPORTS OF LPG MAINLY COMING FROM ARJUNA, RANTAU AND SANTAN FACILITIES.

PRESENT UTILIZATION OF GAS IN INDONESIA IS ILLUSTRATED IN TABLE -2 HERE PRESENTED.

OVERALL UTILIZATION OF GAS IN 1983 TOTALLED ABOUT 1,100,000 MMSCF BROKEN DOWN INTO:

- 54.5% OR 600,000 MMSCF AS FEEDSTOCK (INCLUDING LNG)
- 16.4% OR 180,000 MMSCF AS FUEL
- 29.2% FOR OWN USES IN FIELDS AND TRANSPORTATION SYSTEM,
THIS FIGURE HAVING TO BE COMPARED WITH A TOTAL OF ABOUT 967,000 MMSCF IN 1982.

MAIN ITEMS COVER THE PRODUCTION OF LNG WITH MORE THAN 9,800,000 TONS (OR 505,000,000 MMBTU) HAVING BEEN PRODUCED IN 1983 AND MORE THAN 500,000 TONS OF LPG AS WELL AS SUBSTANTIAL AMOUNTS GOING TO THE INDUSTRIAL PLANTS:

- 155 MMSCFD IN WEST JAVA (CHIEFLY KRAKATAU STEEL, CEMENT CIBINONG, PUPUK KUJANG FERTILIZER PLANT).
- 138 MMSCFD IN SOUTH SUMATRA (CHIEFLY PUSRI II, III, IV FERTILIZER PLANTS).

STARTING FROM A TOTAL AMOUNT OF ABOUT 2,300 MMSCFD OF GAS BEING UTILIZED IN 1983 AS FEEDSTOCK OR FUEL, THE INCREASE IN ONE YEAR WILL EXCEED 50 % WITH THE INTERVENTION OF SEVERAL LARGE PROJECTS READY TO CONSUME ABOUT 1,200 MMSCFD MORE IN 1984, NAMELY:

- THE NEW TWO TRAINS IN EACH LNG PLANT AT ARUN AND BADAK
- THE AMMONIA AND FERTILIZER PLANTS OF PUPUK ASEAN IN NORTH SUMATRA AND KALTIM I IN EAST KALIMANTAN.

A FURTHER ADDITION CONSUMPTION OF ABOUT 500 MMSCFD FOR THE FIRM PROJECTS DURING THE 1985 - 1987 PERIOD CORRESPONDS TO THE FULL OPERATION OF:

- THE AMMONIA AND FERTILIZER PLANTS OF PUPUK
ISKANDAR MUDA IN NORTH SUMATRA AND KALTIM II IN EAST KALIMANTAN, AND THE METHANOL PLANT OF BUNYU, FROM 1985 ON,

- THE AMMONIA AND FERTILIZER PLANT OF PUSRI I IN SOUTH SUMATRA TO RESTART WITH A NEW SIZE FROM 1986 ON,
- THE SIXTH TRAIN OF ARUN LNG PLANT FROM 1987 ON,

ALL THIS WITHOUT TAKING INTO ACCOUNT MINOR INCREASES OF CONSUMPTION IN INDUSTRIAL OUTLETS AS WELL AS THE USE FOR CITY GAS AND LPG FOR EXPORTS.

THE OVERALL CONSUMPTION OF ABOUT 4,000 MMSCFD IN 1987 REPRESENTS A SUBSTANTIAL INCREASE OF ABOUT 75 % OVER THE CORRESPONDING 1983 FIGURE.

THESE FIGURES FOR PRESENT AND NEAR FUTURE SHOW YOU TO WHAT LARGE EXTENT INDONESIA IS INVOLVED IN THE MAXIMUM UTILIZATION OF GAS. SPEAKING ABOUT A MEDIUM OR LONGER-TERM BASIS THE POTENTIAL SUPPLY FROM NATIONAL SOURCES IS VERY HIGH AND CAN EASILY MEET BOTH LNG ADDITIONAL EXPORT AND A DRASTIC INCREASE IN DOMESTIC USES.

AS REGARDS THE REPARTITION OF THESE DOMESTIC USES, WHEN WE CONSIDER THE WHOLE PATTERN ON ECONOMIC SECTORS, EACH OF THEM CAN FIND BENEFITS IN THE USE OF NATURAL GAS; THIS BEING ILLUSTRATED IN FIGURE APPENDED.

NOT SURPRISINGLY INDONESIA HAS ALREADY CHOSEN TO PROMOTE GAS USES IN THE SECTORS WHERE GAS COMPETITIVITY IS THE STRONGEST. IT CONCERNS SYNTHESIS GAS MANUFACTURE
WHERE GAS ENJOYS A VERY FAVOURABLE POSITION IN COMPARISON WITH OIL PRODUCTS, BOTH AS FEEDSTOCK AND FUEL. IN THIS FIELD A COMPREHENSIVE INDUSTRIAL EXPERIENCE HAS BEEN GAINED WITH AMMONIA PLANTS AND DIRECT REDUCTION OF IRON ORE, TO BE SOON COMPLETED WITH METHANOL PRODUCTION.

MOREOVER IN MANY OTHER SECTORS, NATURAL GAS (AND/OR NATURAL GAS LIQUIDS) CAN SUCCESSFULLY COMPETE WITH OIL PRODUCTS.

THE FIRST POTENTIAL OUTLET BY ITS SIZE IS ELECTRICITY GENERATION. I KNOW YOU ARE WELL AWARE OF THE CRITICAL ROLE PLAYED BY ELECTRICITY IN THE ECONOMIC DEVELOPMENT OF ANY COUNTRY AND THE IMPERATIVE NEED TO SUPPLY INDUSTRIAL PLANTS WITH THE MOST COMPETITIVE POWER PRICES. IN THIS SPECIFIC FIELD, HYDROPOWER, GEOTHERMAL AND COAL ARE STRONG COMPETITORS IN OUR COUNTRY. HOWEVER GAS CAN FIND ITS OWN WAY DUE TO THE NOW WELL-ESTABLISHED TECHNOLOGY OF COMBINED CYCLE POWER PLANTS. FOR A RICH-GAS COUNTRY THIS TECHNOLOGY MAY ENSURE QUITE COMPETITIVE COSTS FOR ELECTRICITY DUE TO HIGH ENERGY EFFICIENCY (40 - 45 %), RELATIVELY LOW INVESTMENT (ABOUT HALF THAT NEEDED FOR A COAL-FIRED POWER PLANT) AND REDUCED LEAD TIMES. MOREOVER SMALLER GAS SCHEMES MAY FIND ATTRACTIVE OUTLETS IN THE SETTING-UP OF SMALL POWER PLANTS IN MANY AREAS CLOSE TO MARGINAL OR UNUTILIZED GAS SOURCES.

IN ANOTHER IMPORTANT AND LARGE ENERGY CONSUMING
SECTOR, CEMENT MANUFACTURE, GAS IS IN A POSITION TO SUBSTITUTE FOR OIL PRODUCTS BUT IT WILL ALSO FIND COAL AS A STRONG COMPETITOR.

IN MEDIUM AND LIGHT INDUSTRIES, WHICH ARE FAST GROWING IN INDONESIA, FUTURE OF NATURAL GAS WILL PROBABLY BE VERY BRIGHT. DESPITE COMPETITION FROM FUEL OIL AND, TO A LESSER EXTENT, COAL IN ENERGY MARKETS, GAS REMAINS VERY ATTRACTIVE THERE SINCE IT IS CLEAN IN USE, EASILY CONTROLLED AND REGULATED, WITHOUT SUPPLY DISRUPTION. THUS MANY FIRMS USING STEAM BOILERS AND FURNANCES WOULD PROBABLY PREFER NATURAL GAS IF THE BTU PRICE IS ATTRACTIVE ENOUGH IN COMPARISON WITH FUEL PRODUCTS. EXPECTING THIS PRICE COMPETITIVITY WILL BE ENSURED, GAS PENETRATION IN THIS SECTOR WILL BE HIGHLY LINKED WITH THE DEVELOPMENT OF GAS TRANSPORT AND DISTRIBUTION NETWORK FROM VARIOUS SUPPLY SOURCES TO THE CONSUMING AREAS. A COMPLETE NETWORK FOR ENSURING INTERREGIONAL TRANSFERS OF GAS WILL HAVE TO BE BUILT, INDUCING ON A LONG TERM BASIS MAJOR TRUNK LINES FROM SUPPLYING REGIONS (NORTH SUMATRA, SOUTH CHINA SEA, EAST KALIMANTAN) TO HIGHLY CONSUMING REGIONS (JAVA, SOUTH SUMATRA).

FOR COMPLETING THE PATTERN OF UTILIZATION SOME COMPONENTS OF NATURAL GAS WHICH FIND SPECIFIC OUTLETS WILL BE AVAILABLE.
IT DEALS WITH ETHANE AND PROPANE FOR THE MANUFACTURE
OF OLEFINs FOR WHICH INDONESIA HAS SUCH A PROJECT NEAR
ARUN IN NORTH SUMATRA. IT HAS BEEN REPHASED SINCE LAST
MAY BUT WE ARE CONFIDENT THAT POTENTIAL MARKET FOR OLEFINs
AND DERIVATIVES IN OUR COUNTRY IS LARGE ENOUGH TO GIVE TO
THIS PROJECT A RENEWED INTEREST IN A NEAR FUTURE. IT ALSO
CONCERNS LPG WHICH ARE CONVENIENT FOR HOUSEHOLD, SERVICES
AND WILL PROBABLY PAY A SUBSTANTIAL ROLE AS SUBSTITUTE
FOR KEROSENE WHICH IS, PERMANENTLY, IN SHORT SUPPLY IN
INDONESIA. EVEN TO A MORE LIMITED EXTENT LPG MIGHT FIND
SAME OUTLETS IN THE TRANSPORTATION SECTOR, WHICH REMAINS
THE ONLY ONE PREFERABLY CAPTURED BY THE OIL PRODUCTS.

TO WEIGH THE ACTUAL POTENTIAL OF GAS UTILIZATION
FOR THE BENEFIT OF THE INDONESIA ECONOMY, OUR GOVERNMENT
HAS ORDERED IN THIS FIELD THREE STUDIES FINANCED BY A
WORLD BANK LOAN:

- AN OVERALL GAS UTILIZATION STUDY ON ALL ASPECTS
  OF SUPPLY, DEMAND AND PROJECT PLANNING (BEING PERFORMED
  BY BEICIP CONSULTANTS, FRANCE).

- A STUDY FOR CITY GAS DEVELOPMENT IN THE CITIES,
  OF JAKARTA, BOGOR AND MEDAN (BEING PERFORMED BY OSAKA
  GAS, JAPAN).

- A STUDY ON UTILIZATION OF LPG.

IN CONCLUSION, YOU CAN NOW CONCEIVE, BESIDES
TRADITIONAL INDONESIA LNG EXPORTS, IT EXISTS A VERY
LARGE POTENTIAL DOMESTIC MARKET IN BASIC INDUSTRIES AND OTHER ECONOMIC SECTORS OF ACTIVITY. CONSTANT PRESSURE ON OIL BY INDONESIA ENERGY DEMAND DURING THE END OF THE CENTURY WILL LEAD TO THE SUBSTITUTION BY GAS WHENEVER ECONOMICALLY POSSIBLE. MOREOVER GAS SUPPLY GROWTH CAN BE EASILY SUPPORTED BY EXISTING PROVEN RESOURCES TO WHICH SHOULD BE ADDED LARGE POTENTIAL RESOURCES FROM EXPLORED SEDIMENTARY BASINS (OFFSHORE NORTH SUMATRA, OFFSHORE KALIMANTAN, EAST OF NATUNA) AS WELL AS FROM NOT YET EXPLORED BASINS.

SUCH DELIVERY OF GAS TO CONSUMERS INVOLVES THE BUILDING-UP OF A COMPLEX NETWORK OF PRODUCTION WELLS, GAS TREATING FACILITIES, GAS PROCESSING PLANTS, GATHERING LINES, FEEDERS, COMPRESSION STATIONS AND DISTRIBUTION GAS LINE CORRESPONDING CAPITAL REQUIREMENTS, TO BE ADDED TO THOSE REQUIRED IN ALL UTILIZATION PROJECTS, ARE OBVIOUSLY VERY HIGH AND MAY ONLY BE MET BY USING VARIOUS SOURCES OF FINANCE: INDONESIA GOVERNMENTAL BODIES, INTERNATIONAL AID AGENCIES, EXPORT CREDIT AGENCIES AND COMMERCIAL BANKS. LASTLY, CONTRACTORS WOULD PROBABLY BE HIGHLY INTERESTED IN THE CONSTRUCTION OF ALL UTILIZATION PLANTS AS WELL AS IN THE EXTENSION, OF THE INDONESIA GAS SUPPLY AND DELIVERY INFRASTRUCTURE. LET ME MENTION AMONG THEM: OIL COMPANIES, SHIPBUILDERS,
PIPE MANUFACTURERS, COMPRESSOR AND TURBINE MANUFACTURERS, ENGINEERING FIRMS AND CIVIL ENGINEERING FIRMS.

THANK YOU FOR YOUR ATTENTION.
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<tr>
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<td><strong>OIL</strong></td>
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<td>125,2 (83,3 %)</td>
<td>156,8 (76,1 %)</td>
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<td>21,3 (14,1 %)</td>
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<td>0,4</td>
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<td>SOUTH SULAWESI</td>
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<tr>
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<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SOUTH CINA SEA</td>
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<tr>
<td>Total Indonesia</td>
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Direktorat Eksplorasi dan Produksi
DIT.JEN.MIGAS.
TABLE - 2

INDONESIA
GROWTH IN GAS UTILIZATION
FROM 1983 TO 1987

- 1983 CONSUMPTION PATTERN

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<tr>
<th>Feedstock Including LNG</th>
<th>Fuel</th>
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- CURRENT AND NEAR FUTURE ADDITION (IN MMSCFD)

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|                      | 1214 | 181 | 54 | 265 |

- 1987 GAS UTILIZATION

4000 MMSCFD
ABOUT 40 BILLION CUBIC METER/YEAR

GROWTH: 74%
Figure 1.

NATURAL GAS & ECONOMIC SECTORS

Source "Indonesian Gas Utilization Study"
SYNTHETIC FUEL AND CNG DEVELOPMENT IN NEW ZEALAND

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ABSTRACT

This paper examines New Zealand's experience of synthetic fuels and compressed natural gas (CNG) for automotive use. The country's gas depletion policy is outlined to clarify how the synthetic gasoline venture suits New Zealand's situation but may not necessarily be the precise answer for others. The specific reasons behind the choice of technology and project organisation are described. The places found for US technology and project management in these two areas provide insights into where the best match of Thailand's needs and US expertise may be found. The petrochemical, synthetic fuel and MTBE possibilities for the future that are currently being studied in New Zealand are also covered.
Deletion Policy

New Zealand's offshore gas field was discovered in 1969 and developed in anticipation of high electricity demands. Thus electricity generation was the original planned use for most of the gas and the economic justification for the development of the field.

In the years following discovery, the country experienced much lower than expected electricity demands and rapidly rising oil prices, so the electricity uses were deferred and the emphasis shifted to substituting for imported transport fuels.

Of course, there was always a background envisaged of gas use as a premium fuel in industry and in homes replacing fuel oil and electrical heating. CNG was soon to be added to this list of high-value direct uses. These basic plans for premium uses established a minimum opportunity cost for additional projects. Export of LNG has never seemed extremely attractive, partly because of New Zealand's location and vulnerable position in the Pacific market and partly because of the large scale required.

In 1978, the New Zealand Government established the Liquid Fuels Trust Board (LFTB) to identify appropriate uses for the gas in the changed circumstances. Gas was allocated in a kind of Dutch auction, satisfying high-value uses first, then intermediate-value uses and so on until a balance was struck between current opportunities, prolonging the premium uses and capacity constraints.

Two contributing concerns were to relieve the balance of payments constraint on the economy by favouring direct exports or import substitution, and to increase self-sufficiency in transport fuels. The former was and is reflected by a 10 percent shadow weighting of foreign exchange in Government's cost-benefit analysis while the latter has not reached the point of being accounted for quantitatively.
The strategic decision reached in 1979 after the LFTB report was presented to Government was:

- to reserve as much as required for internal premium uses
- to produce chemical methanol, mainly for export, and
- to use 40-60 PJ per year (110-160 MMscfd) for synthetic fuels,
  this pattern expected to leave half the gas in the ground by
  the year 2000.

The choice of technologies

The options considered by the Liquid Fuels Trust Board included CNG, methanol blends (with petrol), methanol as a base fuel, synthetic petrol and diesel, olefins-based plastics, chemical methanol and LNG, the last three largely for export. Methanol export appeared the best chemical option to match available markets and realise early foreign-exchange benefits. The execution of this venture was left to the private sector and the choice of technology to the project proponents.

The synthetic fuels considered were those from the synthol fluidised bed and Arge processes operating in South Africa and from the Mobil ZSM-5 catalyst. The methanol fuel options were rejected at this stage as making too small an impact in the case of blends, and too difficult for a non-car-manufacturing country to do alone, in the case of M100.

Apart from the South Africans, only Lurgi and US companies were in a position to advise on, or provide, technology at this scale. Parsons was contracted to establish whether the available processes could be improved or adapted to meet New Zealand's particular gas composition and product demand balance. Badger and Lurgi were independently contracted to compare the two Fischer-Tropsch technologies and the Mobil process, taking into account the associated refining requirements for the country's total supply system.
The eventual choice of a synthetic petrol plant plus a hydrocracking extension to the country's refinery was made on the basis of cost, product flexibility and on the total size of the venture. Had more gas been allocated to synfuels, the choice would have been pushed towards the Fischer-Tropsch technologies.

Finally, before the syngas venture was commercially under way, the banks contracted Chem Systems to investigate the whole process and the Government asked the Rand Corporation to report on the final costing of the project (explained below).

**Project Organisation**

In a country with a relatively small industrial base, there are two choices in this type of major resource development: sell the gas and get some major international company to do the whole project, or participate, and gain expertise in the design and implementation stages. With other smaller gas projects possible in the future, NZ chose the latter. For reasons of control, Government also insists on at least 50 percent New Zealand ownership of such resource based ventures. The country as a whole therefore faces most of the project risks, whether or not the plant is privately owned. In order to ensure that any windfall profits remain in public hands, i.e. benefit everyone, the Government has retained direct or indirect ownership of the New Zealand shareholding of the gas based projects. In the case of synthetic petrol plant, it also chose a tolling arrangement as the commercial basis for the venture.

The LFTB reports were submitted and the recommendations accepted at the end of 1979. In April 1980, the Government and Mobil signed a Memorandum of Understanding. This established a Joint Executive Committee (JEC), four nominees from each party, whose task was to prepare a plan for the design, construction and operation of the plant, a detailed cost estimate, and based on these, a technological and commercial appraisal of the
feasibility of the project. The JEC operated as though the venture was underway from that time. The operating company, New Zealand Synthetic Fuels Corporation Limited (NZSFCL) was set up and work proceeded, funded equally by Mobil and the Government.

The Memorandum provided that within 60 days of receiving the JEC report, the Government and Mobil would decide finally whether or not to proceed. Thus the go/no go decision was to be made on the basis of a relatively detailed plant design, a cost estimate for what would then be a better defined plant, and completed contractual negotiations between Mobil and the Crown (so each party would know what its returns were likely to be). The negotiations defined the tolling arrangement under which the Government retained ownership of the gas and the product and paid the company a fixed fee for processing gas to gasoline.

The JEC report was submitted in July 1981 and enabled Government to review the overall costs and benefits of the scheme in the light of the detailed cost estimate (the accuracy of which has contractual significance for the shareholders) and of the then current oil price forecasts and alternative gas use opportunities. In fact, contract negotiations took until February 1982 to be completed and by this time, Government had decided that the project should proceed. Work started almost immediately and funding arrangements made through Asia Pacific Capital Corporation (a Citicorp subsidiary) were finalised in July 1982.

Thus, the momentum of the project was maintained from the design stage onwards, running the risk of losing the money spent on preliminary and selective detailed design if the plant had turned out to be uneconomic, but benefiting by providing the best possible basis for the final decision and saving a substantial time in implementation.
Method of Implementation

The overall supervision of the project was entrusted to Mobil Technical and Project Services (MOTAPS) thus maintaining a close link between the technology developer and the venture management. In more detail, MOTAPS was asked to select contractors, obtain planning consents, complete prefeasibility studies related to design, collect engineering site data, set implementation schedules, establish plant utility requirements, and supervise testing and start-up. Bechtel Petroleum was chosen to supervise the actual construction as well as provide other services. The advantage seen in engaging major companies in these supervisory positions was that one was buying a "system" that had been used before and therefore debugged. The alternative would have been to re-invent such a framework by trial and error.

Design contracts were awarded where the company's experience seemed best to fit. Foster Wheeler had had an early involvement with the Mobil methanol to gasoline (MTG) system and provided the basic process design. The MTG detailed design went to Bechtel who also designed for the integration of the methanol and MTG plants. Davy McKee (both Lakeland and London), with their dominant position in design of world methanol capacity, were chosen to design the methanol plant.

With construction contracts, again an important aim was to guarantee a kind of "leadership" from direct experience, so Davy McKee was also engaged to supervise the construction of the methanol reformers.

As mentioned above, the financing of the project was coordinated by a subsidiary of Citicorp although the funding was syndicated to many non United States banks.
The New Zealand Government assumed responsibility for necessary infrastructure as this was an area in which ample local engineering experience was available. The Government thus undertook to provide gas supply lines, product distribution facilities, water and electricity suppliers and an effluent disposal line.

Construction is now well underway and is expected to be completed by mid 1985.

CNG

Early in the LFTB studies, the benefits of direct use of gas as a transport fuel were recognised. New Zealand's North Island was already extensively reticulated for natural gas and for cars travelling a sufficient yearly mileage, conversion to CNG as seen as clearly in the national interest. Because there are some disadvantages with CNG use like lower performance and reduced luggage space, and because the appropriate vehicles for conversion are most easily recognised by their owners, the programme has been left largely to the private sector.

The role of the Government has been firstly to help get the programme started properly by providing 25 percent grants towards the cost of refuelling stations and secondly by seeing that incentives facing the consumer are sufficient. Grants are made to offset sales tax and duty on conversion equipment, and concessional loans are given for fleet conversions. All suitable Government vehicles have been changed over to CNG.

The aim of the programme is to have about a quarter of the cars in the reticulated area converted by 1990. At present, 6 percent have changed to CNG. For a car consuming 10 litres per 100 km and travelling 10,000 km/year, the conversion with one cylinder would currently be paid back in two years.
Being on a very different technological scale to the major methanol and syngas projects, the CNG market has developed throughout the reticulated area with individual companies finding the best equipment deals they can. Subject only to new and comprehensive safety standards, the competition on cost and quality is open, between about 11 American and Italian conversion kits and a multinational range of compressors and cascade cylinders for refuelling stations. Vehicle equipment from the United States seems to have taken the higher cost, higher performance end of the market.

Future Options

There is currently a substantial exploration programme running in New Zealand. Around US$200 million was spent in the last year and the Benreoch rig is currently drilling offshore. The main interest is in oil but there are obviously chances of another gas find. What would we do with more gas?

Whether or not more gas is found, the ethane and LPG components which comprise 20 percent of the existing gas field are available for extraction and upgrading. The options being studied include polyethulene from the ethane, MTBE from the butane (using methanol from the new plant at Waitara) and synthetic avtur from the propane. Alternatively, the whole LPG component could be dehydrated and passed over the Mobil catalyst to produce petrol and diesel. This "Mobil olefins to gasoline and diesel" process may be of more general interest than the synthetic gasoline one, if the economics prove favourable.

If more reserves are found, synthetic crude could be made from natural gas by the older Arge process or the new Gulf/Badger variant. All these options are being studied during a hiatus in the world oil and petrochemical markets, and there is no urgency in the planning. Without stronger markets, additional gas seems more likely to be used for electricity generation or left in the
ground to prolong the life of direct uses in industry and transport.

Summary

Synthetic petrol suits New Zealand's energy system because of the limited industrial, and chemical export, markets relative to the size of the gas field and because of a general preference for oil substitution over gas exports. It must also be said that the decisions were made at a time when oil price forecasts were higher than they now are.

Once a project of this scale is being seriously contemplated, there seems to be a great advantage in risking some money to refine the cost estimates, especially with less tried technologies. New Zealand's methanol plant, modelled on a Canadian one and commissioned last year, was built on estimate, but the cost of the synthetic petrol plant more than doubled between that first scoping studies by the LFTB and the final contractual estimate. Producing the final ±20% estimate before the decision to proceed, risked 3 or 4% of the total project cost.

With large ventures, efficient execution of the project is at least as important as the choice of technology supplier. New Zealand's experience is that experienced project supervisors are worth the money.

In small scale technologies, the free market works more obviously with consumers making normal trade-offs between cost and reliability.
NATURAL GAS IN PAKISTAN

BY

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2 Gas Transmission System.

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(b): Growth in number of domestic consumers and total consumers in all categories.

5- (a): Sectorwise consumption of natural gas.

(b): Growth in the total consumption.

6- Breakdown of gas consumption by various categories of consumers during 1982-83.
Pakistan has a well established natural gas industry. Its network comprises 3758 km of high pressure transmission lines and 12500 km of distribution lines in 78 major towns/cities in the country. Large reserves of good quality natural gas were found in 1952 at Sui in Baluchistan with a recoverable reserve of 8.6 trillion cubic feet followed by another big strike at Mari in the province of Sind with a recoverable reserve of 3.943 trillion cft in 1957. The recoverable reserves of natural gas so far discovered in the country are estimated at 18.78 trillion cft. of which 3.28 trillion cft have since been utilized.

2. Present utilization of natural gas in Pakistan is 825 million cft/day which level has gradually been achieved ever since the inception of gas era in 1955. It is meeting well over 40% of the commercial energy requirements of the country. Its use has been extended for the manufacture of fertilizer, generation of electricity and for industrial, commercial and domestic consumption. Through progressively increased use of gas in fertilizer manufacturing Pakistan has not only attained autarky but has also become its exporter. The use of natural gas in power generation was the highest until 1981-82 but its consumption in urea production has now surpassed all other uses. In 1982-83, 33% of the total gas produced was used for the manufacture of fertilizer, 25% for power generation and the remaining for industrial,
commercial and domestic consumers. The total number of consumers has grown from 100,000 in 1970-71 to 877,421 in 1982-83.

3. In Pakistan, like other energy deficit countries, the demand management of gas with careful planning and rigid enforcement has become sine qua non in the past 2-3 years. Such efficacious measures as conversion to oil of cement plants has been completed and that of power plants is under-way to balance the precarious gas supply demand proposition.

4. With a view to popularizing the use of gas in the initial period its prices were kept conventionally low. However, with the change in policy from expansion oriented to conservation the consumer prices had to be rationalized in January, 1982. Incentives which encouraged high gas consumption have been withdrawn to cut down its ever increasing demand. The consumer prices of gas were increased from an average of Rs 10 ( $ 1.00 ) per Mcft in 1981 to Rs 20($ 1.5) per Mcft in July 1983. Government has also announced price incentives for producers to encourage development of new gas resources in the country.

5. The two major gas companies in Pakistan viz: Sui Northern Gas Pipelines Limited and Sui Gas Transmission Company Limited have undertaken major gas transmission and distribution projects of national importance. The financing agencies like Asian Development Bank and World Bank have recognised and

(Contd.P/3)
appreciated the professional capability of these companies. Government of Pakistan will be too glad to have the capability of these companies extended to the benefit of Thailand in the field of planning, designing and execution of the pipeline construction projects.
INTRODUCTION

This paper gives an account of developments in gas utilization in Pakistan since the supplies of natural gas first became available in October, 1955. Amongst the developing countries, Pakistan has the longest experience of utilizing natural gas in almost every socio-economic sector. The gas industry in Pakistan has rapidly advanced through these years and has played an important role in the industrial development and the national economy.

GAS RESERVES

2. In 1950s, substantial gas reserves were discovered in the country. The first discovery was made by Pakistan Petroleum Limited (PPL) in 1952 at a remote location namely Sui in the Baluchistan desert. This is the largest gas field so far discovered with recoverable reserve of 8.6 trillion cft. This was followed by other natural gas discoveries during the next few years in the same geological zone at Zin (1954), Uch (1955), Khairpur (1957), Mazarrani (1958) and Khandkot (1958) by PPL and Mari (1957) in the Province of Sind by Esso Eastern Inc. Mari gasfield is the second largest producing field with a recoverable reserve of 3.943 trillion cft. In the public sector Oil & Gas Development Corporation (OGDC) also discovered a small field at Sarising about 64 Km north east of Karachi in 1967 and at Hundi nearby in 1970. Later on OGDC discovered a few more gasfields at Kothar near Hundi, Rodho in Dera Gazi Khan district and Pirkoh at about 70 Km north of Sui in

(Contd.P/5)
Baluchistan. The location of various fields is shown in the map (slide No.1).

3. The total original recoverable reserves from the known gas fields are estimated at 18.8 trillion cft. So far natural gas for commercial utilization has been produced from Sui, Mari and Sari/Hundi along with some associated gas from the oil fields in Potowar area near Rawalpindi. Mari gas has been exclusively used for fertilizer production in the plants located near the field because this gas is not considered suitable for long distance transmission due to the presence of carbon dioxide and nitrogen. Total gas production from these fields up till 30.6.1983 was 3.3 trillion cft as follows:

- **a) Sui:** 2.86 trillion cft (33% of original reserve).
- **b) Mari:** 0.28 trillion cft (7% of original reserve).
- **c) Sari/Hundi:** 0.03 trillion cft (32% of original reserve).
- **d) Associated Gas:** 0.13 trillion cft (29% of original reserve).

Total: 3.3 trillion cft

The remaining recoverable reserves from the discovered gas fields as on 1.7.1983 are estimated at 15.5 trillion cft.

4. The qualitative and quantitative analysis of the gas fields in Pakistan is shown in Table-A (slide No.1).

(Contd.P/6)
SUPPLY OF NATURAL GAS

5. The commercial utilization of natural gas started in October, 1955 when gas from Sui field was transmitted through a 555 Km of 16" diameter steel pipeline for supply to industries south of Sui in Sukkur, Hyderabad and Karachi. The Sui Gas Transmission Company Limited (SGTC) was promoted in 1955 to construct and operate the Sui-Karachi transmission pipeline with a free flow capacity of 74 MMCFD. This capacity was increased to 120 MMCFD with introduction of compression of 4500 HP at Sukkur and Nawabsha each in 1966. This increased capacity also became saturated in 1972-73, which necessitated the construction of 490 Km of 18" diameter pipeline on the right bank of Indus river in 1976-77. The free flow capacity of this pipeline is 135 million cft/day. The capacity of this pipeline includes an input of nearly 10 million cft/day from Sari/Hundi gas fields of OGDC. As would be discussed in the subsequent paragraphs, the demand on the system has been growing rapidly and the entire transmission capacity was fully utilized by 1980-81. The SGTC therefore, undertook the planning for construction of compression facilities on the right bank pipeline. These compression facilities involving 28,000 HP at three points are expected to be commissioned by end March, 1984 and would increase the output of the system to 397 MMCFD. The SGTC has recently completed a 349 Km of 12" dia pipeline for supply of gas to Quetta. The

(Contd.P/7)
free flow capacity of this line is 33 MMCFT/day. In order to meet the gas requirements for the system, Pirkoh gas field is being developed and supplies are expected to commence from that field at the rate of 40 million cft/day by March 1984, increasing to 72 MMCFD from July, 1984.

6. The distribution of natural gas in Sind and Baluchistan is undertaken by two independent companies viz Indus Gas Company Limited (IGC) and Karachi Gas Company Limited (KGC). The later company only distributes gas in the city of Karachi. The natural gas has been made available in 23 significant cities/towns of these Provinces. The aggregate length of transmission lines of SGTC is 1394 Km and the distribution pipelines of KGC & IGC is 5500 Km. This comprises the Southern Gas System supplying gas to 450,000 domestic, 8900 commercial and 980 industrial consumers.

7. Natural gas supply to the areas north of Sui started in 1958 when 347 Km of 16" diameter pipeline from Sui to Multan was completed. This pipeline was initially owned by Pakistan Industrial Development Corporation (PIDC). However, in 1964 a new gas company namely Sui Northern Gas Pipelines Limited (SNGPL) was promoted to take over the Sui-Multan pipeline from PIDC. This company had dual responsibility of transmission and distribution of natural gas in the Punjab and the North Western Frontier Province. The company extended the Sui-Multan Pipeline to Faisalabad in January, 1965 and

(Contd. P/8)
to Lahore and the nearby industrial complex of Kalasha Kaku in June, 1966. The gas supply to Peshawar and other towns of NWFP was commenced in 1971. Subsequently to meet the growing demand on its system, SNGPL has been augmenting its capacity by adding loop lines and compression facilities. At present the company's total transmission system comprises 2364 Km of high pressure lines of various diameters and 87000 HP compression. The system operates at an input pressure of 1070 PSI at Sui and is capable of transmitting 378 MMCFD purified gas. The system includes input of about 30 MMCFD associated gas from oil fields in Potowar area near Rawalpindi. The company's gas distribution network has been extended in 55 cities/towns in the Punjab and NWFP. The aggregate length of the distribution pipelines of various diameters is 7000 Km which is supplying gas to 400,000 domestic, 21,000 commercial and 3,000 industrial consumers.

8. The two transmission systems are shown in slide No.2.

GAS PURIFICATION

9. Natural gas from Sui field contains carbon dioxide (CO$_2$) and hydrogen sulphide (H$_2$S) as impurities. Natural gas to consumers is required to be delivered free of sulphur contents. The international standards provide for presence of sulphur in quantities not exceeding one grains/100 cft. Excessive sulphur may have serious corrosive action on the metals of gas appliances/boilers and very injurious to the catalyst used in urea manufacturing plants. The Sui gas therefore, requires purification before transmission for
commercial utilization.

10. A gas purification plant of 74 MMCFD capacity was installed at Sui in 1955. Subsequently with the growth in the volume of gas which required purification, the capacity of plant was also augmented progressively. Present capacity of the plant is 670 MMCFD in terms of purified gas. The gas purification plant at Sui comprises 9 purification units, of which 5 units have a capacity of 50 MMCFD each, 4 have a capacity of 100-110 MMCFD each. These units are operated by SGTC. The SGTC has proposed to install another purification unit of 120 MMCFD capacity by October, 1985 in order to provide coverage for the periods when various units are taken off for annual maintenance/overhauling and also to cover the periods of emergency breakdowns so that uninterrupted supply of natural gas could be ensured to the consumers. A large complex of ancillary facilities is also operated by SGTC at Sui to support the operation of gas purification plant.

NATURAL GAS AS FUEL

11. The thermal efficiency of any kind of fuel is of great importance. The truly unmatched advantage of gas over other fuels is its efficiency. In any given application the efficiency of the fuel employed is the ratio of useable heat to the total heat originally available from the fuel. Besides it has other advantages which has generated up-precedented demand for gas in the country. These advantages are:-

( Contd.P/10 )
a) **Cleanliness**

Natural gas requires no manual handling and leaves no residual ash after burning. It leaves a clean furnace or equipment after its use. It is free from smoke.

b) **Convenience**

Natural gas provides the most convenient fuel for all forms of utilization. It relieves the consumer of storage worries. It is available in a continuous flow at all the times. It requires no warm up or waiting period by itself. The total heat input with gas can be divided into as many large or small burners as may be necessary adopting them to any heating arrangement, thus delivering the correct amount of heat where and when required and therefore, minimizing the danger of hot spots or poor heat distribution over an area.

c) **Controlability**

Easy and cheap to handle at the point of consumption natural gas is ideal for automatic control. A very fine degree of control can be economically engineered into gas equipment.

d) **Dependability**

The supply and delivery of almost all forms of fuels and energy are liable to interruption since they are not available at the point of consumption. Natural gas on the other hand is always available through its direct transmission system right on the point of consumption.

(Contd. P/11)
e) **Economy**

Natural gas in Pakistan is the cheapest available fuel. Although its prices have been increased progressively in the recent past, yet it has no match with the prices of comparable fuels like kerosene in the domestic sector and furnace oil in the industrial sector.

12. The comparative cost of various fuels used in Pakistan is shown in Table-B (slide No.3).

**UTILIZATION**

13. In Pakistan natural gas has established its application to meet the commercial energy requirement of any type of industry in addition to providing basic raw material for the manufacture of synthetic fertilizer. Within a span of two years after the commissioning of gas transmission in 1955 all large and small industries in the south located in the cities of Sukkur, Hyderabad and Karachi area were using natural gas. Being assured of continuous supply of this indigenous fuel, industrial activity was stimulated.

14. Although the established best use of natural gas is as raw material for manufacturing fertilizers and petrochemicals, yet in an energy deficit country like Pakistan its use as fuel in the Power plants, Cement plants and other industries was encouraged in the early periods. It is now meeting well over 40% of the country's commercial energy requirements. The total consumption of natural gas in 1982-83 was recorded at 301 billion cft which is equivalent to...
10.6 million tons of coal or 7.2 million tons of furnace oil on energy content basis. The value of furnace oil works out to US $ 1300 million. In the absence of development of this indigenous energy resource the fuel import bill of the country would have nearly doubled. The various industries using natural gas as fuel are discussed in succeeding paragraphs.

**POWER**

15. Use of natural gas for power generation is considered to be the least desirable proposition. However, in Pakistan expansion of natural gas network to various cities was initially justified on account of bulk gas requirements of the power plants. Normally 10 cubic feet of gas is required to generate one KWH of electricity in a steam turbine station and 15-20 cubic ft/KWH in a gas turbine station. The steam turbines are primarily used as base load stations whereas gas turbines cover the peak load hours. The total capacity of the thermal power stations which have been based on natural gas in Pakistan is 1950 MW, of which 1500 MW comprises the steam power stations and 450 MW gas turbine stations. The thermal stations would require 400 MMCFD gas on maximum day basis if no other fuel is used.

16. Electric power generation has been responsible for the consumption of over 30% of the country's total gas production till 1981-82. The year 1980-81 recorded the peak gas consumption for the power sector on volume basis i.e. 232 MMCFD which was 32% of the total gas consumption. However, the

(Cont.P/13 )
maximum share of gas in the overall gas consumption was recorded in the year 1976-77 at 36%. The consumption of power has dropped to 203 MMCFD i.e. 24.6% of the total gas consumption in 1982-83. It is expected that the consumption of gas for power generation would still reduce in future as gas would have to be diverted to meet the peak requirements of other industrial consumers. The power plants would meet their balance fuel requirements by using alternate fuels like furnace oil/HSD and they are in the process of making necessary alterations.

CEMENT

17. Like power the use of gas in cement plants has also been condemned. But this was again the bulk consumption of this major sector which justified the extension of natural gas pipeline to various towns/cities and consequently brought industrial development in those areas. Following the natural gas availability, several cement plants which were operating on furnace oil/coal were also converted on natural gas. The total capacity of cement plants in the country is 12,000 tons/day comprising 3000 tons on dry process and 9000 tons on wet process. Total gas requirements of these plants, if no other fuel is used, is 80 MMCFD.

18. The consumption of gas in wet process is 6-7 Mcft per ton of cement production depending upon the efficiency of

(Contd.P/14)
individual plants. The consumption of gas in dry process is around 4-5 Mcft/ton of cement production. With tremendous growth in the demand of gas from other small industries and domestic consumers it became essential to reverse the process of conversion of cement plants to furnace oil. Almost all the cement plants in the country have now been switched over to furnace oil.

19. Consumption of gas by cement plants rose to its maximum i.e. 72 MMCFD during 1981-82 which was 9% of the total gas consumption in the country. The maximum share of gas for cement production was recorded at 16% of the total gas consumption in 1973-74, but the volume was only 57 MMCFD. This indicates the trend in subsequent years of increase in consumption by other consumers particularly the fertilizers.

OTHER INDUSTRIAL APPLICATIONS

20. Ready availability of this indigenous source of energy as fuel provided a sound base for industrial development in the country. The gas network was extended to various areas which had the potential to develop into industrial complexes. A variety of significant industry which has come up on natural gas as fuel could be identified as:-

i) Textile
ii) Soap
iii) Vegetable oil
iv) Sugar
v) Chemical Processing

(Contd. P/15)
21. Use of natural gas in some of the industries where direct heat is involved like glass and ceramics have resulted in substantial improvement in the quality of end products. In textile industry a very fine gas flame is used for the finishing of the cloth. Although individual consumption of most of these industries is not large, collectively it accounts for about 23% of the total gas consumption. The consumption of these industries in Pakistan increased from 131 MMCFD in 1977-78 to 139 MMCFD representing 23% of total gas consumption in 1982-83 which registered a growth rate of 9%.

22. The Pakistan Steel Mills commissioned in 1980-81, alone uses 26 MMCFD gas for internal power generation, blast furnaces, steel making plant, refractories, repair shops complex, hot strip mills and cold rolling mills.

COMMERCIAL AND DOMESTIC

23. Natural gas has been the most attractive fuel for commercial and household consumers in the country because of its various advantages and above all the cheap prices. The commercial consumers are defined as those producing items for direct commercial sale like tea shops, cafeteria, canteens, barber shops, laundries, places of entertainments like cinemas and theaters etc. Natural gas has also been used for central air-conditioning purposes by these consumers. The total consumption of natural gas by the commercial consumers in 1982-83 was
25 MMCFD as compared to 15 MMCFD in 1977-78 thus registering a growth rate of 13%.

24. Natural gas in the residential sector primarily replaces Kerosene in the major cities/towns. Houses have become clean from smoke. Its use has brought innumerable comforts to the households. The number of domestic consumers using natural gas for cooking, space heating and water heating have grown from 400,000 in 1977-78 to 850,000 in 1982-83. Their total consumption in 1982-83 was 79 MMCFD representing 9.6% of total gas consumption as compared to 27 MMCFD representing 5.5% of total gas consumption in 1977-78, a growth rate of 38.5% which shows the popularity of natural gas as fuel for household uses. Besides gas supply to the residential consumers also brings savings to the overall energy import bill. It replaces Kerosene in the urban areas, which is a deficit product. The total consumption of 28,926 MMcft by the households in 1982-83 replaced 650,000 tons of Kerosene on energy content basis, worth US $ 182 million.

25. Growth in the number of consumers during the past 10 years is shown in Table-C. Slide 4 gives a graphical presentation of growth in the number of industrial and commercial consumers. Slide 4-B gives a graphical presentation of growth in the case of domestic consumers and total number of consumers in all categories.

(Contd.P/17)
26. Sectorwise growth in the consumption of gas is shown in Table-D. Slide 5-A gives a graphical presentation of sectorwise consumption and slide 5-B that of growth in the total consumption since 1970-71.

27. Slide No. 6 gives a graphical picture of the breakdown of gas consumption by various categories of consumers during 1982-83.

NATURAL GAS IN AUTOMOTIVES:

28. The use of natural gas in the form of compressed natural gas (CNG) has been proven as a safe automotive fuel from the consumers' point of view. With a view to substituting the imported oil and petroleum products, Hydrocarbon Development Institute of Pakistan (HDIP) has launched a pilot project for the use of CNG in road transport. Initially the project envisaged conversion of diesel as well as gasoline vehicles to CNG. However, subsequently efforts to convert diesel vehicles were slowed down due to the various economic factors. It has been established by the HDIP that 120 cubic ft of gas is equivalent to one gallon of motor gasoline against 200 cubic ft to one gallon of HSD due to separate firing mechanism of the two fuels in the respective internal combustion engines, therefore conversion of petrol vehicles is more economical and attractive proposition. The cost of converting one gasoline driven vehicle on CNG is estimated at US $ 500.

(Contd.P/18)
This includes the cost of conversion kit, cylinder for CNG storage and allied equipment.

29. At present one CNG refuelling station at Karachi which has been established by the HDIP, is operating. More than a hundred gasoline driven cars and one 22 tonner Fiat Zorzi diesel truck have converted on CNG. All these vehicles operate on dual fuel system and are successfully running for the last two years. The performance evaluation and acceptability of the new fuel has been established. Plans are under consideration to embark upon a phased programme of commercialization of CNG operation by converting 21000 vehicles and establishing 33 refuelling stations in various major cities of the country. The consumption of natural gas by 21000 vehicles is estimated at only 4.8 MMCFD which would replace 44000 tons of gasoline per year. With the implementation of the above programme Pakistan would become the third country in the world (after Italy and New Zealand) for utilization of natural gas in road transport on a commercial scale.

**NATURAL GAS AS RAW MATERIAL**

30. The synthesis of organic chemicals from the natural gas is based on its two constituent elements i.e. carbon and hydrogen. A very large number of chemical products, plastics, synthetic fibre and synthetic rubber etc. could be made from natural gas. The lean natural gas discovered in Pakistan required initial high cost to manufacture these chemicals. Therefore, attention was mostly focussed on the manufacturing of synthetic fertilizers from natural gas.
31. The largest single use of natural gas for chemicals is for the fixation of atmospheric nitrogen for use as fertilizer. The importance of fertilizer in increasing agricultural production especially in irrigated farming has been well recognized in Pakistan. For the manufacture of synthetic fertilizer such as urea virtually no other raw material besides gas is necessary. Urea has a double nitrogen content of ammonium sulphate and is one of most obvious end product of natural gas. Under a phased programme the capacity to produce urea using natural gas as raw material has been increased tremendously during the last 10 years. At present 7 fertilizer factories are operating in the country. Their installed capacity is to produce 5500 tons of urea per day and 2800 tons/day of other forms of synthetic fertilizers like Nitro-Phos, Calcium Ammonium Nitrate and Ammonium Sulphate, for application according to the specific requirements of different types of soils and crops. Three fertilizer factories namely Exxon Chemicals, Fauji Fertilizer and Pak-Saudi Fertilizer with a capacity of 4090 tons/day have been based on use of Mari gas and are located close to the field. Mari gas which contains CO₂ is considered to be better for the production of urea. The other four factories namely Pak-China, Pak-American, Dawood Hercules Chemicals and Pak-Arab fertilizer with a total capacity of 4210 tons/day are operating on supplies from SNGPL on the northern gas system. The consumption

(Contd.P/20)
of natural gas for fertilizer production has been arisen from 87 MMCFD representing 18% of total consumption in 1977-78 to 270 MMCFD representing 33% of the total gas consumption in 1982-83 and has registered a growth rate of 42% and has also emerged as the single largest sector of gas consumption. In the past power generation was the largest consumer of natural gas. Through progressive increase of use of natural gas in fertilizer production Pakistan has not only attained autarky, but has also become its exporter. It is estimated that during the year 1983-84 about 300,000 tons of urea would be available for export to other countries.

32. In the present day circumstances the real benefit of fertilizer does not accrue from exports, but it comes from application within the country for increasing the agriculture production. This analysis is based on the fact that the international market price of Urea is around US $ 140 to 150 per ton. In Pakistan the average consumption of gas in producing one ton of Urea is 40 Mcft. If the said quantity of gas has to be substituted by furnace oil, it would require about 0.96 ton of furnace oil (41.8 Mcft= one ton of F.O.). The international market price of F.O. is 180 $ per ton, thus giving a net loss of US 23-33 $ per ton of Urea export.

VEGETABLE OIL PROCESSING

33. Natural gas has been widely used in Pakistan by vegetable oil processing industry for the hydrogenation of oil

(Contd.P/21)
for solidification, which is a common form of marketable oil product in Pakistan and is locally known as 'vegetable ghee'. However, the quantity of gas used for hydrogenation is comparatively very small as compared to the quantity used by the same industry as fuel in their boilers.

COMMERCIAL EXPLOITATION OF GAS FIELDS

34. The exploitation of gas fields for utilization on commercial scales depends on four basic factors:

   i) Quality of gas.
   ii) Quantity of gas.
   iii) Location of gas field.
   iv) Price of gas.

35. In some of the gas fields, the quality of gas would justify production of gas but the quantity and location would become a hurdle. In another case, the quantity and location could justify the development of gas field on commercial scale but the quality would become a bottleneck.

36. In Pakistan the above factors have played a major role in the development of selected gas fields. We have so far developed gas fields of Sui, Mari and Sari/Hundi along with the utilization of associated gas from the oil fields in Potowar area. The optimum level of production of the Sui field which is 880 MMCFD of raw gas has been steadily achieved and this field would now be producing at this maximum rate till the year 2000 after which decline is expected to start. In
order to maintain the production and the pressure at the existing level, wellhead compression will be introduced along with the drilling of additional development wells within the next 2 years. The Mari gas contains 14.1% CO₂ and 19.5% nitrogen. The presence of these gases did not encourage long distance transmission of this gas. However, the presence of CO₂ in the Mari gas would help urea production better than the normal natural gas. It was under this consideration that three major fertilizer factories have been located close to the field and they are producing 4090 tons of urea/day using 170 MMCFD of Mari gas. The Mari gas field has a potential to produce another 100 million cft of natural gas which would now be used for power generation in 450 MW combined cycle being located close to the field by the Water & Power Development Authority of Pakistan.

37. The Sari/Hundi gas fields were exploited only after SGTC's 18" diameter Sui-Karachi pipeline passed through these gasfields. Independent exploitation of these gas fields was not economically justified earlier.Similarly the independent development of Mazarani gas field has not been considered justified, but with the change in the gas pricing policy the owners of the gasfields are considering to develop the gasfield shortly. The gas field of Pirkoh discovered by OGDC is being developed to supplement supplies to southern Gas System. This field would be initially developed to produce 72 MMCF/day of natural gas from July, 1984. Further development would be

(Contd.P/22)
undertaken after careful evaluation of the results of the earlier efforts. The Khandkot gasfield is being developed to supply gas to WAPDA's new 210 MW steam turbine station at Guddu.

38. The qualitative and quantitative analyses of the gasfields namely Uch, Zin and Khairpur could not justify their development on commercial scales. Possibilities of exploitation of the gas reserves of these fields for commercial utilization are now receiving attention. The other gas fields are quantitatively poor in addition to their remote locations and their independent development is still not economically justified.

DEMAND MANAGEMENT

39. Natural gas transmission system particularly the northern system is facing a growing problem of seasonal swings in gas pipeline load requirements. The consumption of natural gas in the northern parts during the winter months of December, January and February escalates nearly by 50% as compared to the normal rate of consumption. In addition WAPDA's thermal power plants also require more gas during winter months because of the shifting of load from the Hydro power to the Thermal generation. The gap between supply and demand during winter peak months of 1983-84 is estimated at 248 MMCFD. Since it is neither possible to increase supply nor the transmission capacity to match the seasonal peak demand, the only recourse
available is the Demand Management. This objective has been achieved by rationing of natural gas supply to the major consumers like power plants, cement plants, fertilizer factories and sugar mills etc. The remaining gap is met by load shedding on general industries. This situation has been experienced for the past three years and is likely to continue in subsequent years also until supply could be increased to match the peak demand. The Government has therefore embarked upon a demand management programme with the following objectives:

i) Education of public to improve efficiency of gas appliances for maximising production with minimum gas consumption.

ii) Conservation of natural gas and cutdown its wasteful/luxurious uses in the residential sector through pricing mechanism.

iii) Interfuel substitutions. In this connection the cement plants have been completely switched over to furnace oil and planning for conversion of power plants is in hand.

iv) The larger consumers like fertilizer factories are taken off for annual maintenance during winter peak months in order to minimize the effect of load shedding on smaller industrial consumers.

v) With a view to cut down the ever increasing demand of natural gas, restrictions have been imposed on the number of new gas connections both in the residential as well as industrial sector.

(Contd.P/25)
vi) The industrial connections in future are being allowed only on 9 monthly basis. They will not be supplied gas during the winter months of December, January and February each year.

**GAS PRICES**

40. A number of aspects of current and future development of energy resources are directly influenced by the pricing policy. The policy tools available for managing energy demand and reducing wasteful use are pricing, physical controls, technical methods and education and propaganda. The matter of pricing at all levels of the energy sector and for all forms of energy, especially gas is of vital concern since the various activities relating to natural gas production, transmission and distribution play very important role in the country's economy.

41. The entire matter of gas pricing from the wellhead to the end consumer is clearly one involving many technical financial and national considerations. Various criteria are in vogue such as guaranteeing a certain rate of return on investment, linkage with international price, fixing prices on the basis of heat content basis, pricing to encourage certain interfuel substitutions and conservation, prices based on long run marginal cost and pricing influenced by socio-economic considerations. At times, prices are also used as a tool of management to create incentives for exploitation of indigenous resources.

42. The price of gas at the well-head is normally fixed guaranteeing a fixed return to the producers after meeting all the development and prospecting expenditure. In the case of transmission companies their retaining prices are fixed

(Contd.P/26)
on the basis of financial criteria laid down by the international financial institutions like World Bank and Asian Development Bank. Incentives have been announced by the Government for development of new gas reserves in the country. The Government is prepared to negotiate with prospective producers a base price of gas which should be sufficient to generate 12% internal rate of return net of taxes and allow recoupment of investment in 12 years or the life of the field whichever is earlier.

43. The prices of natural gas for consumers were initially devised on a sliding slab system to encourage higher gas consumption. This was basically aimed at popularising the use of this indigenous source of energy and obtaining an optimum level of production from the known gas reserves as early as possible so as to reduce dependence on the imported energy. Under this policy it was possible to increase the consumption of gas from about 10 MMCFD in 1955 to 180 MMCFD in 1965-66, to 483 MMCFD in 1976-77 and to 825 MMCFD in 1982-83. The consumption in future years is not likely to grow at the historical rate because of the constraints in the supply position, but still with the development of new gas reserves the growth is likely to continue at about 7%.

44. In order to arrest the ever growing demand of gas, to implement conservation measures and to curb the wasteful and luxurious use of natural gas the old pricing system was

(Contd.P/27)
changed and prices were rationalised in January, 1982. Incentives devised earlier to encourage higher gas consumption were withdrawn. In the residential sector a new system was introduced to penalise higher gas consumption as under:

For first 7 Mcft/month Rs 16/Mcft ($1.2/Mcft)
For next 3.5 Mcft/month Rs 20/Mcft ($1.5/Mcft)
For all over 10.5 Mcft/month Rs 24/Mcft ($1.8 /Mcft)

45. This policy soon brought the desired results and most of the consumers changed their habits of more gas consumption. With such fiscal measures, it is also possible to get useful results in other sectors of consumption. The prices of consumers have increased from an average of Rs 10 per Mcft ( $1.00 per Mcft ) in 1981 to an average of Rs 20 ( $1.5 ) per Mcft in 1983.

REGIONAL CO-OPERATION

46. The two major gas companies in Pakistan namely Sui Northern Gas Pipelines Limited (SNGPL) and Sui Gas Transmission Company Limited (SGTC) are operating a very sophisticated gas transmission network comprising 3758 Km of high pressure pipelines ranging from 6" to 20" diameter with 1,34,000 HP compression. A telecommunication network all along the transmission pipeline has been built to provide telemetry and tele-control in addition to the speech and teleprinter circuits. The two companies have constructed these pipelines departmentally. The two companies have also undertaken construction of 900 Km of 16" diameter oil pipeline from Karachi to
Multan in addition to some smaller projects. The pipeline projects executed by the two gas companies are spread over practically every type of country including the deserts, rivers, canals, swamps, rocks mountains and green fields under the most difficult climatic conditions with temperatures ranging from below freezing point to as high as 50°C. The international financing agencies like Asian Development Bank (ADB), World Bank and Kuwait Fund for Arab Economic Development have recognised and appreciated the professional capabilities of these companies in accomplishing such complicated projects. The Government of Pakistan will be too glad to have the capabilities of these gas companies extended to the benefit of Thailand or any other region in the field of planning, designing and execution of the pipeline construction projects.

CONCLUSIONS

Pakistan's experience of nearly 30 years in gas industry has lead us to draw the following conclusions:

i) Exploitation of natural gas on commercial scale largely depends upon the quality and quantity of the gas reserves. The wellhead price for the producer is the most effective tool to expedite the development of a gas field to its optimum level.

ii) Energy deficit countries are promoted to use indigenous natural gas resources mostly for burning purposes to replace the imported fuels. In Pakistan, use of indigenous natural
gas as fuel has stimulated the industrial activities thereby bringing multiple benefits to the country's economy.

iii) Use of natural gas for generation of power and production of cement should be restricted.

iv) Sectoral priorities in the use of natural gas may be decided by individual countries keeping in view their specific requirements and the socio-economic considerations. Use of natural gas in the households may not be discouraged but pricing system could be devised to restrict the use of natural gas in the households for living purposes and to curb luxurious uses.
<table>
<thead>
<tr>
<th>Place</th>
<th>Quality</th>
<th>Heating value</th>
<th>Original reserves</th>
<th>Balance reserves 1.7.1983</th>
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<tr>
<td></td>
<td>Methane %</td>
<td>CO₂ %</td>
<td>N₂ %</td>
<td></td>
</tr>
<tr>
<td>Sui:</td>
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<td>7.5</td>
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</tr>
<tr>
<td>Zin:</td>
<td>46</td>
<td>45</td>
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<td>Uch:</td>
<td>27</td>
<td>46</td>
<td>25</td>
<td>308</td>
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<td>Khairpur:</td>
<td>12</td>
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<td>Mari:</td>
<td>66</td>
<td>14</td>
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<td>674</td>
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<td>Mazarani:</td>
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<td>970</td>
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<td>79</td>
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<td>840</td>
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<td>2</td>
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<td>Rhodho:</td>
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<td>NA</td>
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<td>843</td>
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<td>NA</td>
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<td>Kothar:</td>
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<td>NA</td>
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<td>NA</td>
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<tr>
<td>Moyal/Toot Oil Field:</td>
<td>90</td>
<td>6</td>
<td>1</td>
<td>1150</td>
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</table>

**TOTAL:** 18.78 15.48
### TABLE B

**COMPATIVE COST OF VARIOUS FUELS**

<table>
<thead>
<tr>
<th>FUEL</th>
<th>COST PER UNIT ($)</th>
<th>AVERAGE CALORIFIC VALUE (BTU)</th>
<th>COST OF FUEL EQUIVALENT ($ per MCFt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Natural gas for domestic use:</td>
<td>1.2 per thousand cubic feet</td>
<td>975/cft</td>
<td>1.2</td>
</tr>
<tr>
<td>2. Natural gas for industrial use:</td>
<td>1.5 per thousand cubic feet</td>
<td>975/cft</td>
<td>1.5</td>
</tr>
<tr>
<td>3. Natural gas for commercial use:</td>
<td>2.2 per thousand cubic feet</td>
<td>975/cft</td>
<td>2.2</td>
</tr>
<tr>
<td>4. Furnace oil:</td>
<td>127.4 per metric ton 40750/KG</td>
<td></td>
<td>3.1</td>
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<tr>
<td>5. Wood:</td>
<td>2.1 per 40 KG</td>
<td>14980/KG</td>
<td>3.6</td>
</tr>
<tr>
<td>6. Steam coal:</td>
<td>5.3 per 40 KG</td>
<td>27640/KG</td>
<td>5.1</td>
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<td>7. L.P.G. (Domestic)</td>
<td>3.0 per cylinder (11.8 KG)</td>
<td>49000/KG</td>
<td>5.1</td>
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<td>8. Kerosene:</td>
<td>2.0 per 10 litre</td>
<td>42000/litre</td>
<td>5.8</td>
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<tr>
<td>Year</td>
<td>Industrial</td>
<td>Commercial</td>
<td>Domestic</td>
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<td>----------</td>
<td>------------</td>
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<tr>
<td>1973-74</td>
<td>2241</td>
<td>8862</td>
<td>155162</td>
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<tr>
<td>1974-75</td>
<td>2548</td>
<td>10934</td>
<td>193452</td>
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<td>1975-76</td>
<td>2916</td>
<td>13384</td>
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<td>3092</td>
<td>15682</td>
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<td>1977-78</td>
<td>3182</td>
<td>18076</td>
<td>404266</td>
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<td>1978-79</td>
<td>3437</td>
<td>20746</td>
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<td>1979-80</td>
<td>3576</td>
<td>23234</td>
<td>577110</td>
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<td>1980-81</td>
<td>3812</td>
<td>26204</td>
<td>677997</td>
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<tr>
<td>1981-82</td>
<td>3909</td>
<td>29032</td>
<td>780909</td>
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<tr>
<td>1982-83</td>
<td>4017</td>
<td>30421</td>
<td>842983</td>
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### TABLE - D

**DISTRIBUTION OF GAS CONSUMPTION BY SECTOR**

<table>
<thead>
<tr>
<th>YEAR</th>
<th>Residential</th>
<th>Commercial</th>
<th>Cement</th>
<th>Fertilizer</th>
<th>Power</th>
<th>General Industries</th>
<th>Total</th>
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<tr>
<td>1970-71</td>
<td>1,745</td>
<td>1,710</td>
<td>18,484</td>
<td>14,484</td>
<td>43,344</td>
<td>26,876</td>
<td>106,643</td>
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<td>1971-72</td>
<td>2,261</td>
<td>1,945</td>
<td>16,399</td>
<td>22,286</td>
<td>40,793</td>
<td>27,830</td>
<td>111,514</td>
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<tr>
<td>1972-73</td>
<td>2,983</td>
<td>2,305</td>
<td>20,888</td>
<td>27,685</td>
<td>43,330</td>
<td>30,121</td>
<td>127,312</td>
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<tr>
<td>1973-74</td>
<td>3,917</td>
<td>2,988</td>
<td>23,054</td>
<td>30,030</td>
<td>48,549</td>
<td>35,961</td>
<td>144,499</td>
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<td>1974-75</td>
<td>5,065</td>
<td>3,520</td>
<td>24,688</td>
<td>31,203</td>
<td>51,801</td>
<td>40,589</td>
<td>156,746</td>
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<tr>
<td>1975-76</td>
<td>6,206</td>
<td>4,214</td>
<td>23,848</td>
<td>31,625</td>
<td>49,515</td>
<td>41,507</td>
<td>156,915</td>
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<tr>
<td>1976-77</td>
<td>7,498</td>
<td>4,684</td>
<td>22,535</td>
<td>31,805</td>
<td>60,837</td>
<td>41,666</td>
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<td>1977-78</td>
<td>9,733</td>
<td>5,287</td>
<td>24,236</td>
<td>31,873</td>
<td>60,072</td>
<td>47,852</td>
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<td>1978-79</td>
<td>11,987</td>
<td>6,029</td>
<td>24,208</td>
<td>40,750</td>
<td>60,801</td>
<td>49,883</td>
<td>190,658</td>
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<td>1979-80</td>
<td>14,536</td>
<td>6,570</td>
<td>25,847</td>
<td>46,333</td>
<td>81,070</td>
<td>54,719</td>
<td>229,075</td>
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<td>1980-81</td>
<td>17,142</td>
<td>7,590</td>
<td>26,120</td>
<td>65,921</td>
<td>84,722</td>
<td>62,152</td>
<td>263,614</td>
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<td>1981-82</td>
<td>23,679</td>
<td>8,375</td>
<td>26,455</td>
<td>76,042</td>
<td>81,624</td>
<td>67,255</td>
<td>283,440</td>
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<td>1982-83</td>
<td>28,926</td>
<td>9,030</td>
<td>21,760</td>
<td>98,481</td>
<td>74,078</td>
<td>68,825</td>
<td>301,100</td>
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</tbody>
</table>

227
Gas Fields of Pakistan

Legend

Methane

Carbon Dioxide

Nitrogen

Original recoverable reserves in million million cubic feet e.g. Sui 8.62.
Distance in Miles e.g. Mari-Sui 40 miles

Approximate Distance from Karachi

<table>
<thead>
<tr>
<th>Location</th>
<th>Distance (Miles)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sari</td>
<td>45</td>
</tr>
<tr>
<td>Hundi</td>
<td>60</td>
</tr>
<tr>
<td>Kothar</td>
<td>70</td>
</tr>
<tr>
<td>Mazarani</td>
<td>200</td>
</tr>
<tr>
<td>Khairpur</td>
<td>225</td>
</tr>
<tr>
<td>Uch</td>
<td>270</td>
</tr>
<tr>
<td>Kandhkot</td>
<td>260</td>
</tr>
<tr>
<td>Mari</td>
<td>260</td>
</tr>
<tr>
<td>Sui</td>
<td>290</td>
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<td>Zin</td>
<td>295</td>
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<tr>
<td>Rodho</td>
<td>510</td>
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<tr>
<td>Pir Koh</td>
<td>323</td>
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<tr>
<td>Dhodak</td>
<td>518</td>
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COST OF FUEL EQUIVALENT

0
1.2
2.2
3.1
3.6
5.1
5.8

US $/MCF

FUEL

NATURAL GAS FOR DOMESTIC USE

NATURAL GAS FOR INDUSTRIAL USE

NATURAL GAS FOR COMMERCIAL USE

FURNACE OIL

WOOD

STEAM COAL

L.P.G.

KEROSENE
TABLE D

SECTOR-WISE GAS CONSUMPTION

1 - COMMERCIAL
2 - RESIDENTIAL
3 - CEMENT
4 - POWER
5 - FERTILIZER
6 - GEN. INDUSTRIES
### TABLE-D
TOTAL GAS CONSUMPTION

<table>
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<tr>
<th>YEARS</th>
<th>1970</th>
<th>71</th>
<th>72</th>
<th>73</th>
<th>74</th>
<th>75</th>
<th>76</th>
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<th>78</th>
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<td>250,000</td>
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</tbody>
</table>

**AVERAGE ANNUAL GROWTH RATE**
9.6 %
GAS SALES
1982-83.

FERTILIZER
32.7%

GEN. INDUSTRIES
22.9%

POWER
24.6%

DOMESTIC
9.6%

CEMENT
2.7%

<table>
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<tr>
<th></th>
<th>MMCF.T.</th>
<th></th>
<th>MMCF.T.</th>
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<tr>
<td>POWER</td>
<td>74,078</td>
<td>FERTILIZER</td>
<td>98,481</td>
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<td>CEMENT</td>
<td>21,760</td>
<td>INDUSTRIES</td>
<td>68,825</td>
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<tr>
<td>DOMESTIC</td>
<td>28,926</td>
<td>COMMERCIAL</td>
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235
INTRODUCTION

Compressed natural gas has been proven to be a high-quality economical fuel in many countries and its benefits are greatest in countries where liquid fuel resources are limited but locally produced natural gas is readily available. These conditions gave impetus to development of the CNG industry in Italy and currently are the primary reasons for the development programs underway in New Zealand, Canada, Bangladesh, Pakistan and several other countries. Thailand is endowed with extensive natural gas resources which could readily be used to replace gasoline and diesel fuel in the transportation sector.

Even though natural gas may be produced at very high pressures at the wellhead, it is usually available from the transmission grid at pressures below 1000 psig. In sub-transmission systems and distribution networks the pressure may be 100 to 200 psig, or even less. In order to store sufficient natural gas on-board the vehicle the gas must be compressed to high-pressures, usually in the range of 2400 psig to 3600 psig. Research efforts are underway to develop low-pressure (ca 150 psig) storage techniques, but, as yet, these are not commercially available. Gas compression equipment and techniques have been used for many years and the pressures involved are well within the capability of commercial equipment. However, CNG compression poses some special problems and limitations which must be considered.
Corrosion problems may be increased at high pressure so additional clean-up may be required even though the gas has already been scrubbed and sweetened for pipeline transmission.

The equipment must be capable of compressing relatively small volumes at high compression ratios.

Compression efficiency should be high in order to minimize compression costs.

The equipment should be capable of sustained long term operation. Many industrial compressors are designed for short-term intermittent duty and under continuous load will fail quickly.

Fuel metering is difficult and costly because of the small volumes and high pressures involved. Empirical methods, based on volumetric calculations, suffice in some instances but may not be acceptable for custody transfer and billing purposes.

The equipment must be designed for complete safety. It must withstand high pressures as well as the shock and abuse of everyday use and be simple enough that untrained personnel can operate it without creating safety hazards.

Many fueling stations have been built and operated successfully. These include "fast-fill", "time-fill" and satellite stations. The compressors used include reciprocating compressors, hydraulic compressors and booster compressors which utilize the energy available at a pressure reduction station to compress a portion of the gas stream. While most stations are directly attached to the pipeline network, satellite stations have been built in Italy and New Zealand. The satellite stations receive CNG via high-pressure tube trailers from remote compressor stations and store it for delivery to vehicles. The various types of stations and the equipment used and the economics of fueling station operation are reviewed in this paper.
TECHNICAL DISCUSSION

The fueling station includes gas purification, compression, storage and metering facilities. Normally it would be designed to receive natural gas at pressures ranging from about 50 psig. to 500 psig. and to deliver the CNG to the vehicle at pressures up to 3000 psig. In some countries the fueling stations provide only CNG, but in New Zealand and Italy a single fueling station may provide gasoline, diesel fuel, CNG and LPG.

Gas Purification

Before natural gas is transported through high pressure transmission pipelines it is usually scrubbed to remove corrosive impurities such as carbon dioxide and sulfur compounds. Few instances of corrosion damage have been identified so gas purification is not normally included in refueling stations. However, if untreated gas is used purification may be required to eliminate the contaminants. Although corrosion is actually caused by carbon dioxide and hydrogen sulfide, water must be present for corrosion to occur. Therefore, many CNG refueling stations incorporate a purification system which will remove all three. Molecular sieve purification systems are effective and simple to operate. Other systems such as caustic scrubbing are more complex and require considerable labor for operation and maintenance.

Types of Stations

A variety of fueling systems are used, the selection depending upon the needs of the user. Fleet stations which are used to fuel the owner's vehicles may use either a fast-fill or time-fill system. As shown in Figure 1, the fast-fill system compressor fills a large volume surge tank which is coupled, via a series of sequencing valves, to the vehicle fuel tank. It has the advantage that a small capacity compressor may be operated continuously to keep the surge tank filled while the vehicle fuel tank can be quickly filled from the surge tank. Refueling time is usually 3 to 5 minutes so the quick-fill is almost always used at public fueling stations and often at
fleet stations. Some quick-fill cycles utilize a two-stage method in which the vehicle tank is filled partially from the surge tank and then "topped off" with a high-pressure compressor. This system, which is gaining acceptance in New Zealand, is said to be cheaper than the standard quick-fill sequencing cascade system.

Figure 1 also shows the time-fill method. This method is used when the vehicles can be taken out of service for several hours. Typically, a utility would use time-fill for its service vehicles which are in service for only one shift each day. The off-shift period would allow ample time for refueling which might require 4 to 8 hours. At a time-fill station the vehicle fuel tank is coupled directly to the compressor discharge manifold and gas is pumped directly from the feed line to the tank with no intermediate cascade or surge tanks. The advantage is a somewhat simpler system and lower investment costs, but the longer filling time may be a disadvantage. Many fleet station operators are now providing for both quick- and time-fill. The quick-fill system can be used to top-up partially empty tanks or for daytime refueling while the time-fill system serves the baseload requirements.

The satellite system (or travasai, as it is called in Italy), is a specialized fueling system which has been adopted in Italy and New Zealand to serve areas outside the pipeline network. High pressure tube trailers are used to transport natural gas over the highway from a conventional CNG station to a remote station. The trailer tubes may serve as the storage reservoir or the CNG may be decanted into permanently installed cylinders. In either case, the tube trailer capacity can only be partially utilized unless a compressor is installed at the satellite station. While satellite stations fulfill a specific need, they are more costly than conventional stations and have not been widely used.

Another specialized fueling station is the small capacity packaged unit. These units are now offered by several manufacturers in the United States. It has been suggested they might be used as a "home compressor" by individuals, but they have found greater acceptance for small fleet
applications. Figure 2 presents a typical layout for both the fast-fill and time-fill stations using the OMC compressor system. The smaller units have the advantage of low cost—less than $10,000 for the OMC compressor/cascade system—and ease of installation. However, their low capacity limits applications. A consortium of American, New Zealand and Canadian companies are currently carrying out research programs to develop a low cost "home compressor". It would be matched with the low pressure storage system the consortium is developing to provide the residential consumer with a low cost method of refueling his automobile at home.

Metering and Dispensing

Metering is not a significant problem for fleet operators who are concerned only with overall fuel consumption. They may wish to check individual vehicle performance but the volumetric methods now widely used are accurate enough for those purposes. However, if CNG is sold at a public station, accurate and consistent metering is essential. The volumetric method, in which the fuel tank pressure is measured before and after filling and then the volume of gas injected into the tank is calculated by an empirical formula, is fairly accurate but it does not fully account for tank heating during the fill cycle. Now several other direct measurement metering methods are available. Accurate metering is difficult because small volumes must be measured at very high pressures. Standard positive displacement meters are not sufficiently accurate over the full operating range so specialized meters have been developed. One mass flow meter has been tested in New Zealand and is commercially available for CNG stations. It can be coupled to a digital billing system so the customer's fuel can be measured and the bill prepared automatically.

The final link between the fueling station and the vehicle is the dispensing system. Figure 3 shows a typical dispensing station which incorporates a pressure differential metering system. The system must be designed to operate safely and not create a hazard for either the station attendant or the vehicle operator. The most common problems encountered are
"drive-aways", that is, the motorist drives away from the pump with the fill hose still attached, and high pressure gas leaks. Leaks are reduced by using positive coupling high pressure fittings. A male coupling on the fill line fits into a female fitting mounted on the vehicle and automatically seals shut. When the tank is filled, as shown by the tank pressure gauge, the fill valve is shut, the high pressure residual gas vented off, and the line disconnected. The line cannot be disconnected while under pressure. Drive-aways can be prevented by automatically locking off the vehicle's ignition while fueling and many fleet vehicles are so equipped. However, this is cumbersome for public stations so a fail-safe method has been devised. As shown in Figure 1, the dispensing unit includes a breakaway mast which would collapse if the car pulls away while still coupled to the fill line. When the mast collapses the gas flow is automatically shut off. These precautions assure safe operation even under unusual circumstances.

ECONOMICS

Refueling costs are a significant, though not major, element of the cost of CNG. The costs associated with the capital investment, labor and utility costs are the principal components. Investment costs will vary, depending on the type of station used. Time-fill fleet fueling stations normally will require the least investment. Quick-fill stations will be somewhat more expensive, in terms of number of vehicles fueled, and satellite stations will be the most expensive. Home compressor stations will be costly, when it is considered that only a few vehicles will be fueled, but the initial investment will be only a few thousand dollars (or a few hundred if the R & D effort is successful).

Refueling stations require energy for driving the compressor and usually electric motors are used. Some operators have considered using gas engine drivers on the compressors but no standard package units are commercially available. In some instances the refueling station can be built at a pressure reduction station—a city gate station or a large industrial meter station—where the pressure is dropped from several hundred psig. to a few psig. Gas booster compressors which use the energy in the high pressure
gas stream can be used to compress a small portion of the gas to very high pressures. One such unit is sold by Haskel, Incorporated and has been used for CNG as well as other gases. The gas booster consumes no external energy but it is more costly than conventional reciprocating or hydraulic compressors. Compressor power requirements will vary depending on the type, capacity, pressure ratio and duty cycle. However, for a typical four-stage unit, it can be assumed 8-10 kw-hr. of electricity will be required per 1000 cubic feet of gas compressed. Cooling water requirements are modest but a water supply will usually be required. Station operators need not be specially trained to refuel vehicles. Mechanical skills are required to maintain and repair the station equipment but these can usually be obtained by means of a maintenance contract. A station supervisor should be available to assure that safe practices are maintained but his expenses could also be shared with other station functions.

Using the economic format established for this symposium, the cost of refueling was computed, as shown on Table 1. The refueling cost, expressed in terms of costs per equivalent gallon, will be affected by the number of vehicles fueled and the station load factor. Costs were calculated for three different size stations, a large station which would refuel 300 vehicles per day; an intermediate size, fueling 200 vehicles; and a small, 70 vehicle, station. The unit cost ranges from $0.17 per equivalent gallon for the largest station to $0.30 per equivalent gallon for the smallest. Natural gas is priced at $4.00 per MCF, $0.48 per equivalent gallon, so the "pump price" of CNG delivered to the vehicle would be $0.65 to $0.78 per equivalent gallon.

CONCLUSIONS

The technology of CNG refueling stations is well established and a broad range of proven and economical equipment is available. Refueling is a safe operation, certainly no more dangerous than gasoline refueling so long as the station is well-engineered and operated according to good safety practices. CNG can be dispensed in stations where gasoline or other fuels are sold and service station attendents can handle all but the most complicated

* It has been assumed 1 U.S. gallon of gasoline is equivalent to 120 cubic feet of natural gas.
maintenance procedures. Operating costs are significant but not excessive. The principal cost components, other than capital related costs, are for operating labor and electricity. The cost of compressing and dispensing CNG would normally be in the range of $0.15 to $0.30 per equivalent gallon, depending on the type of station, the size and load factor.

In view of the significant benefits CNG can offer to Thailand and other countries where natural gas is readily available but liquid fuels are in short supply, it would appear a strong effort should be mounted to identify CNG's benefits. A program which would confirm the economics of supplying CNG to replace gasoline and diesel fuel; which would show the public that CNG is a safe reliable fuel; and which would demonstrate that a locally produced fuel could reduce dependence on imported petroleum, appears to be merited.
In the **fast fill** system gas is pumped by the compressor (1) to the storage cascades (2) where it is stored until the vehicle is connected to the hose attached to the cascade panel (3). The system is turned to the "on" position and a regulated supply of natural gas passes from the cascade reservoir via the fill post assembly (4) directly to the cylinders in the back of the vehicle. A vehicle can usually be filled in three to five minutes.

The compressor in the **time fill** system pumps regulated natural gas through a high pressure piping system (5) to the fill post assembly (6). Each of the fill posts are equipped with hoses, valves and fill receptacles for filling two or four vehicles. The gas passes through the filling receptacles directly to the cylinders in the vehicles.

Source: Gas Service Energy Corporation

**Figure 1:** CNG FUELING SYSTEM
Figure 2: CNG MINI STATIONS

Source: OMC Corporation
Source: Dual Fuel Systems, Inc.

Figure 3: CNG DISPENSING TERMINAL
Table 1. Economics of CNG Refueling

<table>
<thead>
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<th>Capacity, vehicles/day</th>
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<th>200</th>
<th>70</th>
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<tr>
<td><strong>Utilities</strong></td>
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<tr>
<td>Electricity</td>
<td>7.2¢/eq.gal.</td>
<td>7.2¢/eq.gal.</td>
<td>7.2¢/eq.gal.</td>
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<tr>
<td>Cooling Water</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
</tr>
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</table>

| **Operating Costs**    |     |     |    |
| Labor and supervision  | 4.3 | 5.8 | 7.2 |
| Maintenance            | 0.6 | 0.9 | 2.2 |
| Administration, etc.   | 0.9 | 1.3 | 2.0 |

| **Capital Costs and depreciation** | 2.4 | 3.4 | 8.6 |

| **Taxes** | 0.4 | 0.6 | 1.5 |

| **Total Costs** | 17.0 | 20.4 | 29.9 |

| **Natural gas, $4.00/MCF** | 48.0 | 48.0 | 48.0 |

| **Pump Price** |     |     |    |
| $/equivalent gallon | 65.0 | 68.4 | 77.9 |
| $/MCF            | 5.42 | 5.70 | 6.49 |
"ON-BOARD EQUIPMENT NECESSARY TO CONVERT AUTOMOBILES TO OPERATE ON COMPRESSED NATURAL GAS"

BY: JAMES E. LEWIS
AND
GREGORY MACOSKO

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THAILAND-UNITED STATES NATURAL GAS UTILIZATION SYMPOSIUM
BANGKOK, FEBRUARY 7-11, 1984
INTRODUCTION

The use of natural gas as a vehicle fuel and the equipment necessary for engine conversion to compressed natural gas (CNG) has been proven under a wide range of actual operating conditions. Compared with gasoline, natural gas has a higher octane rating, burns cleaner, improves ignition, reduces certain maintenance requirements and costs, and provides significant fuel cost savings.

Disadvantages are its low energy density, which leads to on-board fuel storage difficulties, and the lack of an in-place refueling network for vehicle use. The fuel storage issue has been addressed by compressing the gas and storing it under pressure in commercially available high pressure cylinders. Both fleet-dedicated and public refueling facilities are technically feasible and are in operation.

This paper describes the basic on-board vehicle equipment needed for natural gas conversion, and analyzes briefly the technical, economic and marketing problems which must be considered in the development of natural gas as an alternate fuel.

CONVERSION EQUIPMENT

There are three alternatives for converting vehicles to operate on natural gas. Gasoline engines can be operated under either a dual or a mono fuel system. Historically, most natural gas vehicles have been converted
to a dual fuel system which permits the driver to choose either gasoline or CNG operation. The second alternative is conversion of the gasoline engine to operate on natural gas only. Interest is growing in mono fuel conversion because it provides some performance benefits and assures maximum savings from natural gas operation (i.e., the driver has no choice). An additional alternative is the conversion of diesel engines to operate on a combination of natural gas and diesel fuel. Diesel conversion technology is still being developed, and there are relatively few vehicles around the world operating under this system.

We will consider only gasoline engine conversion, and most of the equipment described in this paper is common to both dual and mono fuel operation. Equipment manufacturers supply end-users through either distributors or special assemblers who adapt equipment specifically for CNG use. Assemblers usually provide training for mechanics, and they either convert the customer's fleet themselves or supervise a local garage or the fleet's mechanics in the installation of the equipment. Although most of the equipment is not "exotic", drivers and mechanics are not familiar with some of its components, installation requirements and operating characteristics. The refueling equipment which includes compressors is probably the best example, and this area is covered separately in a paper by Tom Joyce.
Exhibit 1 shows that a number of components are necessary to convert a gasoline engine to operate on natural gas. The most important are the air/fuel mixer and the pressure regulator. The pressure regulator's basic function is to receive CNG at a high pressure from storage cylinders and reduce it to a pressure which can be accepted by the air/fuel mixer.

The mixer physically replaces the air filter and handles the functions of the carburetor. In a dual fuel conversion, the carburetor remains in place to permit the driver to switch between CNG and gasoline operation. Mixers must be adapted to fit various makes and models of gasoline engines, and therefore, there are perhaps 400 different mixer configurations for the many engine models in the marketplace. Such product variety means that manufacturers have little opportunity to reduce cost through manufacturing and distribution economies of scale. A few universal mixer models which could handle a range of engines would help to reduce the cost of vehicle conversion.

There are a variety of approaches to the problem of delivering natural gas in a form which can be used by a gasoline engine, and there are a number of U.S. manufacturers of these products. The largest and the oldest is Impco which adapts a few common components to overcome individual engine differences.
Fittings, hardware, hoses, fuel gauge and selector switch are other components required to convert an engine to CNG. Dual fuel conversion creates a performance problem because the optimum point at which the spark plug fires the fuel mixture is not the same for natural gas and gasoline. While it is possible to set firing time at a point between natural gas and gasoline, this causes sub-optimal performance in both modes. A spark advance device permits the operator to switch firing time automatically to the optimum point for the fuel being used. Clearly, spark firing can be set permanently on vehicles which operate only on CNG and therefore require no additional conversion component. Tri-Fuel has used digital technology to develop a spark advance device.

The problems of storing CNG on-board a vehicle are considerably different from those involved in converting an engine to CNG operation. To many people, the words "high pressure" immediately raise concerns about safety. The gas industry is addressing this concern, and the Canadian government has conducted collision tests which demonstrate the high degree of safety of CNG cylinders. Rear-end collisions were done on vehicles operating on gasoline, LPG and CNG, and CNC was shown to be the safest. Other tests and operating experience confirm these findings.
CNG storage involves trade-offs between vehicle weight, storage space and performance. Steel CNG cylinders capable of storing the equivalent of seven gallons of CNG and weighing approximately 200 pounds provide a range of 200+ kilometers, depending on vehicle fuel efficiency. Achieving a greater range in a mono fuel conversion requires additional CNG cylinders, but this results in additional weight and storage space and has some effects on engine performance. Structural Composites Industries was one of the first manufacturers to supply aluminum cylinders to the CNG market.

Vehicle conversion kits have been the traditional method of selling CNG equipment in the U.S. and most other markets. Exhibit 2 lists the typical components of such a kit. Distributors or assemblers of such kits rarely manufacture basic components, but they do modifications and serve a critical role as an interface between the manufacturer and the final user of conversion equipment. Some kit components are adaptations of standard products from other markets, and because there are a variety of gasoline vehicles, a certain expertise is needed to assemble the proper configuration of conversion kit components to fit different vehicles. As previously mentioned, assemblers provide mechanic training and oversee equipment installation.
Kit assemblers must have a local presence to reach potential conversion customers. However, in any new market, initial sales are small, and therefore, a national presence may be necessary to achieve sufficient sales volume. Again, some sort of trade-off between a national and local presence is required, and U.S. assemblers have chosen to have field representatives bring sales leads to the national organization. Fleet mechanics or local garages are trained at the assembler's national headquarters to perform vehicle conversions.

There are a number of assemblers or packagers of CNG conversion kits in the United States. Tri-Fuel and Nu-Fuel are examples of assemblers which are also involved in the manufacture of engine components.

**TECHNICAL DEVELOPMENT**

The U.S. market has been a difficult one for alternate fuels because they must compete directly with gasoline and diesel, two fuels which are well established in the transportation market. On a world basis, U.S. prices for petroleum-based fuels are relatively low, and the U.S. government has offered no attractive incentives or rebates (other than the Investment Tax Credit) to those who convert to alternate fuels. This free market environment, however,
has encouraged participants to analyze marketing and technical development and to achieve competitive advantages. Selection of the optimum CNG system for a particular fleet involves a trade-off between cost, driving range, performance and weight. U.S. manufacturers are addressing these issues on a technical basis to improve the choices for CNG converters.

Research and development of CNG storage cylinders attacks the problems of weight, driving range and to some extent performance. Structural Composite uses unique manufacturing techniques developed for rocket casing motors to fabricate cylinders out of aluminum and wrapped fiber glass. Less weight with equal or greater fuel storage capacity addresses two of the issues for CNG cylinders.

Accurately measuring the flow of natural gas as it is compressed in on-board cylinders creates problems because the velocity, density and temperature of the gas varies radically during refueling. Micro-Motion has developed a unique flow meter which works on the Coreolis principle and which accurately measures natural gas flow in kilograms. Most new refueling stations in Canada, Italy, New Zealand as well as the U.S. are now installing these devices on compressors.
The most attractive conversion candidates have traditionally been large fleets. By researching small compressor technology, U.S. manufacturers will increase their market by making it possible for fleets of less than 15 vehicles to convert to CNG. RIX was the first manufacturer to produce small compressors designed for the home or small fleets. Norwalk has developed a full line of compressors, and offers a complete service station package which is installation-ready.

The electronics revolution has made possible new approaches to the problem of operating a gasoline engine on CNG. The vast majority of CNG conversions in the U.S. use Impco mixers. This company's technical expertise is now being applied to a new fuel management system which will adapt original equipment computers in gasoline engines to optimize CNG operation. Tri-Fuel is researching a fuel injection system which would greatly simplify the number of designs necessary to convert the many different car models.

The spark advance has been a significant development to improve both CNG performance and mileage on dual fuel vehicles. In the first CNG conversions, mechanics were
forced to set spark plug firing at a point which compromises both gasoline and CNG performance. Tri-Fuel developed a digital component to automatically advance timing and also to provide a hotter spark. This compensates for the fact that CNG burns more slowly and requires more spark energy to allow combustion pressure to peak in the correct relation to the piston stroke.

CNG only or mono fuel operation addresses the cost issue because it eliminates the need for some gasoline and CNG components. The automotive OEMs are interested in this conversion approach because it simplifies the CNG fuel delivery system, and also eliminates back-up carburetion and pollution control components.

Low pressure natural gas storage which uses adsorption technology is the newest development in our industry. Future Fuels is aggressively experimenting with this conversion approach because it significantly reduces the size and cost of the compressor needed to refuel vehicles.

**CNG CONVERSION DECISION FACTORS**

Payback or return on initial investment (ROI) has always been the most critical conversion decision factor. Because the U.S. has no public refueling points for CNG, large centrally-based fleets have been the primary targets for
CNG conversion. Such fleets have enough vehicles to defray the high investment and operating cost of a private refueling facility.

There are three basic factors which influence ROI and therefore influence a particular fleet's decision to convert to CNG. Using some reasonable assumptions shown in Exhibit 3, it is possible to demonstrate how variations in fleet size, differential between gasoline and natural gas price, and fuel usage per vehicle affect ROI. Exhibit 4 shows how ROI increases to an optimum fleet size of 40 centrally-located vehicles. Remember that the investment figure for all of the exhibits includes the high cost of setting up a private refueling facility which is not necessary if public refueling is available.

Exhibit 5 demonstrates how greater fuel usage per vehicle improves ROI. As the "gallons" of CNG a vehicle uses in a single day increases, daily fuel savings increases as well. The gallons of fuel used are also influenced by the vehicle's fuel efficiency and the number of miles driven per day. A vehicle with a large gasoline engine which is driven 200 kilometers each day is a very good candidate for conversion to CNG.

Exhibit 6 shows how variation in the price differential between gasoline and natural gas affects ROI.
If the price of gasoline decreases or the price of natural gas increases, then the differential between the two fuels will decrease. Similarly, if the price of gasoline is high while CNG price is low, then the price differential between the two fuels will be large. Exhibit 6 shows that this is a very significant decision factor because changes in price differential can significantly affect ROI and fuel cost savings.

MARKETING AND SERVICE INFRASTRUCTURE

While it should be obvious that CNG economics and return on investment strongly affect the decision to convert, the introduction of a potential converter to the idea of CNG conversion is very important. Conversion is a major capital investment, more than $100,000 for large fleets with a private refueling facility. Exhibit 7 illustrates six separate steps in CNG conversion and how these steps are influenced by five different groups of suppliers. The letters in each box of the matrix are evaluations of the various participant groups in the U.S. market. While it is impossible to go into the intricacies of this exhibit here, our study of the U.S. market shows that it is very important for a fleet which is converting to CNG to have assistance at each step in the process. CNG is a developing market, and anyone converting their fleet requires both technical and operational assistance. Therefore, a local expert who
can handle individual problems is the ideal participant in this market.

Developing the infrastructure for the CNG market is critical if a national government is interested in reducing its dependence on petroleum and utilizing available natural gas for transportation applications. Operating vehicles on natural gas is impossible without some means of converting and refueling them with CNG, in other words, an infrastructure. Private refueling of CNG has thus far been the only option available in the U.S., and this places a high investment penalty on CNG when compared with diesel or gasoline. Exhibit 8 shows ROI for diesel, natural gas and LPG when compared with gasoline. Diesel has a much better ROI than natural gas because diesel operation does not require a private refueling facility. Public availability of CNG makes it a much more attractive transportation fuel alternative and individual vehicle owners as well as fleets can convert. A public refueling network would increase CNG penetration of the total vehicle population, and Exhibit 9 shows how favorably natural gas compares with diesel if refueling facility investment cost is excluded. In this U.S. example, a fleet of 20 school buses each operating 15,000 miles per year has an ROI which is almost 50 percent. This figure is one third higher than that of buses operating on diesel.
THE IDEAL CNG VEHICLE MARKET

What benefits could Thailand derive from developing its CNG vehicle market? If these benefits are attractive, how can the development be accomplished? It would have been nice if Henry Ford had placed a natural gas engine in his first Model T, but we must deal with the fact that every country's vehicle population is powered by gasoline and diesel engines. For any nation, the ideal development scenario would involve CNG fuel availability and a supporting infrastructure as widespread as that of gasoline and diesel. The first requirement, in the ideal situation, is ready availability of natural gas nationwide, or at least in significant population centers and along major transportation routes. The second requirement is public CNG refueling stations which are as common as gasoline or diesel stations, and which offer CNG at a price below gasoline, making it attractive for the average driver with an average automobile to convert to natural gas. High penetration of the vehicle market by CNG will not be possible unless CNG equipment is distributed as widely as automotive parts, and unless a large number of mechanics are able to install and repair CNG equipment. The final ingredient for success is a strong government program to develop and promote the CNG market on a national basis.
This development scenario is ideal and not practical in the near-term. Government or industry alone cannot develop the CNG market without close cooperation among key participants. The first step is commitment to a CNG program which incorporates government, industry and customers. All three groups must recognize the opportunities and benefits, and understand the incentives. If companies see a long term commitment by their government to encourage the growth of this new market, they will participate both as converters and equipment suppliers. However, no one should be expected to participate in the market without being assured that there is a definite plan to nurture market expansion. No country has unlimited resources, and a well-defined plan must initially target those converters with the greatest potential. From a practical standpoint, there is no "one best way" to achieve development. Determining the best approach under a given set of circumstances requires an understanding of the market and infrastructure options. Vehicle types, daily usage patterns, business and population concentrations, and the automotive service network need to be examined to formulate cost effective incentives and a feasible development strategy.

After careful study of its own market, Thailand should draw upon the experiences of other countries. New
Zealand is setting up a public refueling network and making conversion very inexpensive through government support, so that private individuals as well as fleets are converting to CNG. Canada has relatively low oil prices and a rather diverse and complex market infrastructure. Government support is initiating market penetration by CNG of business and public fleets. The U.S. is also a highly complex market, but we have had limited encouragement from our government. CNG suppliers are faced with a highly competitive market.

U.S. manufacturers and distributors have seen their market shift radically over the last four years because of relative energy price changes, and therefore they can assist Thai government and business in establishing realistic market incentives and the needed service infrastructure. Businesses will benefit from a growing and profitable market, and they will be attracted to the market during its initial development by government financial incentives and later by high self-perpetuating growth. The government will reap national benefits from industrial growth, the creation of jobs and greater energy self-sufficiency. Converters, both fleets and private individuals will benefit from lower transportation costs and more stable fuel prices.

In perhaps five years (after the next jump in oil prices), others may look to Thailand to find guidance for a
lesson which many countries will have to learn: How can a nation divorce its transportation system and indeed its economy from the uncertainties of oil prices by making natural gas an economic alternative to gasoline?
EXHIBIT 1

Figure 1. Components of a compressed natural gas (CNG) combination refueling system.

1. Natural gas cylinder
3. High pressure fuel line
4. Fuel selector switch and gauge
5. Natural gas fill valve
6. Pressure reducer and natural gas solenoid valve
7. Original equipment gasoline carburetor
8. Natural gas mixer
9. Gasoline solenoid valve

SYSTEM OPERATION OF A CNG VEHICLE
Natural gas is compressed to 2,400 psi by a special high pressure compressor and is placed aboard the vehicle through the natural gas fill valve (5) where it is transferred to high pressure cylinders permanently installed in the rear of or other convenient location on the vehicle. When natural gas is required by the engine, it leaves the cylinders (1), passes through the manual shut-off valve (2), through the high pressure fuel line (3), and enters the engine area. At this point, the natural gas enters a pressure reducer (6). Here, the pressure is reduced from 2,400 psi to about 90 psi pressure. The solenoid valve, wired in series with a vacuum safety switch, is used to shut off the natural gas supply when the engine is not running or when it is being fueled by gasoline. After the natural gas solenoid valve has opened, the natural-gas passes through a second stage pressure reducer which drops the pressure from 1/4 psi to atomospheric pressure and then into a specially designed natural gas mixer (8) where it is properly mixed with air, flows down through the gasoline carburetor (7), and enters the engine’s combustion chambers. The gasoline supply to the gasoline carburetor is controlled by the gasoline solenoid valve (9). A fuel selector switch (4) is provided so that the operator of the vehicle can select fuel from either the CNG fuel system or the gasoline system.

Figure 2. Components of a CNG vehicle system.
EXHIBIT 2

CNG CONVERSION KIT ASSEMBLY

Engine Components
- Natural Gas Mixer
- Pressure Regulator
- Solenoid Valves
- Fuel Selector Switch and Gauge
- Vacuum Hoses and Connectors
- Cables, Adaptors, Brackets and Hardware
  * Spark Advance (Optional)

On-Board Fuel Storage
- High Pressure Cylinders (size and number vary)
- Cylinder Valves
- Manual Shut-off Value
- High Pressure Fuel Line
- CNG Fill Valve
- Manifolding and Metal Guards
- Cylinder Brackets and Hardware
EXHIBIT 3

PRE-TAX 5-YEAR ROI PROJECTIONS(1)

Base Case Assumptions

* Fleet Size: 35

- Sedans: 10 (30%)  
- Vans: 10 (30%)  
- Pickups: 13 (35%)  
- Medium Trucks: 2 (5%)

Vehicle Equipment Installation Costs:

- Sedans: $250-350  
- Vans: $350-400  
- Pickups: $200-300  
- Medium Trucks: $300-350

* List Price for equipment with all available options
- 3% freight charge
- Estimated start-up investment: $107,435

Refueling Station

* - 50% Quick Fill/50% Slow Fill  
  (40% of demand available in first hour)
* - 5 gallon/vehicle/day

Initial Fuel Cost (delivered)

* - Gasoline(2): $1.00/gallon (fleet wholesale)
* - Natural Gas(2): 0.60/gallon (commercial rate)
* - Electric: 0.065/kwh compression cost
* - Road Tax: 0.08/gallon
* - System in operation 6 months following proposal

Finance

* - External financing handled independently
* - 30% tax rate
* - Private fleets (businesses and some utilities)
  * First year investment tax credit
  * 3 year accelerated vehicle equipment depreciation
  * 5 year accelerated refueling station depreciation
* - Government fleets
  * No investment tax credit
  * 5 year straight line vehicle equipment depreciation
  * 20 year straight line refueling station depreciation

* Systematically varied assumptions
(1) Developed with assistance from Phillips Energy Corporation, Clearwater, Florida.
(2) The initial prices of gasoline and natural gas were escalated over a five year period according to rates projected by Energy Economics Research Inc., Mechanicsburg, Pennsylvania.
EXHIBIT 4

PRE-TAX ROI PROJECTION: FLEET SIZE VARIATION

5 YEAR AVERAGE ROI

PRIVATE

NUMBER OF VEHICLES IN FLEET (ONE LOCATION)
EXHIBIT 5

PRE-TAX ROI PROJECTION: FUEL USAGE PER VEHICLE VARIATION

5 YEAR AVERAGE ROI

50% 60%

2 3 5 8 10 15

"GALLONS" OF NATURAL GAS PER VEHICLE PER DAY
EXHIBIT 6

PRE-TAX PROJECTION: GASOLINE/NATURAL GAS PRICE DIFFERENTIAL VARIATION

5 YEAR AVERAGE ROI

50%

60%

30

20

10

$.10 $.25 $.40 $.55 $.70

GASOLINE/NATURAL GAS PRICE DIFFERENTIAL
EXHIBIT 7

CONTACTS BETWEEN THE CONVERTER AND NATURAL GAS CONVERSION INDUSTRY PARTICIPANTS

<table>
<thead>
<tr>
<th></th>
<th>Prospect Development</th>
<th>Lead Follow-Up</th>
<th>The Proposal</th>
<th>Closing The Sale</th>
<th>Installation</th>
<th>Conversion Follow-Up</th>
</tr>
</thead>
<tbody>
<tr>
<td>GAS UTILITY</td>
<td>P</td>
<td>P</td>
<td>*</td>
<td>P</td>
<td>D</td>
<td>D</td>
</tr>
<tr>
<td>KIT ASSEMBLER</td>
<td>D/P</td>
<td>D</td>
<td>D</td>
<td>D</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>MANUFACTURER</td>
<td>*</td>
<td>P</td>
<td>P</td>
<td>*</td>
<td>P</td>
<td>*</td>
</tr>
<tr>
<td>INSTALLER (IF SELF-INSTALLED)</td>
<td>*</td>
<td>P</td>
<td>D</td>
<td>P</td>
<td>D</td>
<td>*</td>
</tr>
<tr>
<td>LOCAL CONSTRUCTION COMPANY</td>
<td>*</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>D</td>
</tr>
</tbody>
</table>

D: DEFINITE INVOLVEMENT
P: POSSIBLE INVOLVEMENT
*: NO APPARENT INVOLVEMENT
EXHIBIT 8

ROI COMPARISON (1) BY MILES DRIVEN OF COMPETITIVE ALTERNATE FUELS (2)
(INCLUDING REFUELING FACILITY)

ANNUAL ROI

75%

50

25

AVERAGE MILES PER YEAR

5,000 10,000 15,000 22,000 30,000

DIESEL (3)

NG (4)

LPG (5)

(1) ALTERNATIVES ARE COMPARED WITH GASOLINE $1.00/GAL.
(2) ESTIMATES BASED ON HAYES/HILL INTERVIEWS AND INTERNATIONAL HARVESTER PUBLISHED INFORMATION.
(3) DIESEL: $1.02/GAL., $4,700 VEHICLE PREMIUM.
(4) NG: 60¢/GAL., $4,200 VEHICLE PREMIUM, 20 BUS FLEET.
(5) LPG: 85¢/GAL., $1,470 VEHICLE PREMIUM, 20 BUS FLEET.
EXHIBIT 9

ROI COMPARISON(1) BY MILES DRIVEN OF COMPETITIVE ALTERNATE FUELS(2) (EXCLUDING REFUELING FACILITY)

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Annual ROI</th>
</tr>
</thead>
<tbody>
<tr>
<td>NG (3)</td>
<td>100%</td>
</tr>
<tr>
<td>Diesel (4)</td>
<td></td>
</tr>
<tr>
<td>LPG (5)</td>
<td></td>
</tr>
</tbody>
</table>

AVERAGE MILES PER YEAR

(1) ALTERNATIVES ARE COMPARED WITH GASOLINE $1.00/GAL.
(2) ESTIMATES BASED ON HAYES/HILL INTERVIEWS AND INTERNATIONAL HARVESTER PUBLISHED INFORMATION.
(3) NG: 60¢/GAL., $1,725 VEHICLE PREMIUM, 20 BUS FLEET.
(4) Diesel: $1.02/GAL., $4,700 VEHICLE PREMIUM.
(5) LPG: 85¢/GAL., $1,225 VEHICLE PREMIUM, 20 BUS FLEET.
EXHIBIT 10

COSTS OF COMPETITIVE VEHICLE CONVERSION SYSTEMS

$4,700

?  

$2,300-2,500

$700-800

$1,200-1,300

REFUELING FACILITY

$1,550-1,900

$275-350

$600-650

$675-900

REFUELING FACILITY

$1,325-1,625

$250-300

$300-400

$550-650

CONVERSION KIT

CYLINDERS

LNG

COMPRESSED NATURAL GAS

DIESEL

(1) INITIAL PREMIUM PER VEHICLE OVER THE COST OF A GASOLINE POWERED VEHICLE.
(2) INTERNATIONAL HARVESTER 6.9 LITER DIESEL.
(3) BASED ON A 20 BUS FLEET CONVERSION.
**EXHIBIT 11**

**LOGISTIC CHAIN EFFICIENCY**

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Efficiency</th>
<th>Energy Loss</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Extraction</td>
</tr>
<tr>
<td>Methanol</td>
<td>57%</td>
<td>2.4%</td>
</tr>
<tr>
<td>LNG</td>
<td>74%</td>
<td>2.9%</td>
</tr>
<tr>
<td>LPG</td>
<td>81%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Compressed natural gas</td>
<td>78-86%</td>
<td>3.3%</td>
</tr>
<tr>
<td>Gasoline</td>
<td>84%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Diesel</td>
<td>86%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Electricity (coal generated)</td>
<td>26%</td>
<td></td>
</tr>
</tbody>
</table>

(1) Does not include energy losses during consumption.

EXHIBIT

SIMPLIFIED STRUCTURE OF THE NATURAL GAS FLEET CONVERSION MARKET
(INdicating Representative Participants)

NG Vehicle Equipment

<table>
<thead>
<tr>
<th>MANUFACTURING</th>
<th>NATIONAL DISTRIBUTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPARK ADV.</td>
<td>FITTINGS</td>
</tr>
<tr>
<td>'AUTOTRONIC'</td>
<td>(VARIETY)</td>
</tr>
<tr>
<td>'TRI-FUEL'</td>
<td></td>
</tr>
</tbody>
</table>

NATIONAL VENDORS/DISTRIBUTORS

- 'DUAL FUEL'
- 'OMC'
- 'ADVANCED FUEL'
- 'CNG SYSTEMS'

REGIONAL/LOCAL SALES/DISTRIBUTION

- COMM. SALES REFS. (OMC)
- DISTR./DEALERS (OMC)
- REGIONAL & LOCAL VENDORS/DISTRIBUTORS
  - 'TRI-FUEL'
  - 'NU-FUEL'
  - 'PHILLIPS'
  - 'JOY'
  - 'GAS SERVICE'

INDUSTRIAL DISTRIBUTORS

DIRECT SALES-MEN

GAS UTILITIES

- CONTR. REFUELING STATION
- PUBLIC REFUELING (CANADA)
- SELF-INSTALL

PRIVATE SECTOR

- 75+ VEH.
- 35-75 VEH.
- 10-35 VEH.

PUBLIC SECTOR

- CARS
- VANS
- TRUCKS
- BUSES
- 'ELECTRIC TELEPHONE GAS'

UTILITIES

SOURCE: HAYES/HILL INTERVIEWS.
Appendix

U.S. MANUFACTURERS/ASSEMBLERS
OF CNG VEHICLE CONVERSION EQUIPMENT

<table>
<thead>
<tr>
<th>Company</th>
<th>Products</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Atlas-Copco</td>
<td>Air cooled compressor, 31 cfm, 3600 psi</td>
<td></td>
</tr>
<tr>
<td>104 Lower Westfield Road</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Holyoke, MA 01040</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (413) 536-0600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Autotronic Controls Corp.</td>
<td>Spark advance (Dual Curve Ignition)</td>
<td></td>
</tr>
<tr>
<td>6908 Commerce</td>
<td></td>
<td></td>
</tr>
<tr>
<td>El Paso, TX 79915</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (915) 772-7431</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Roger Priegel, Marketing</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beam Products Mfg. Co. Inc.</td>
<td>Regulators, mixers, carburetor adapters, solenoid valves and accessories</td>
<td></td>
</tr>
<tr>
<td>3040 Rosslyn Street</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Los Angeles, CA 90065</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (213) 247-7050</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lawrence C. Zonker, Pres.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CNG Cylinder Corporation Subsid. of Alcoa, Inc. Lafayette, IN 47903</td>
<td>Manufactures aluminum composite CNG cylinders</td>
<td>CNG has a unique cold-forming manufacturing process to form a variety of cylinder sizes which are wrapped with fiberglass. Some have been used for remote natural gas collection and the conversion of diesel tankers.</td>
</tr>
<tr>
<td>Tel: (317) 448-3390</td>
<td></td>
<td></td>
</tr>
<tr>
<td>J. Steve Murray, VP-Mktg.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corken International Corp.</td>
<td>A continuous-duty horizontal gas compressor which is oil-free</td>
<td></td>
</tr>
<tr>
<td>3805 NW 36th Street</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oklahoma City, OK 73112</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (405) 946-5576</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dana Dorr, Ind. Sales Mgr.</td>
<td>Acquires complete conversion equipment packages; offers six compressor models specifically adapted for CNG</td>
<td>Dual Fuel is the oldest CNG equipment assembler in the U.S. and exports products to New Zealand, Pakistan and other countries.</td>
</tr>
<tr>
<td>Dual Fuel Systems Inc.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6140 Bristol Parkway</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Culver City, CA 90230</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (213) 726-7336</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Al Sayles, Vice President</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Essex Cryogenics of MO Inc.</td>
<td>Conversion kits for CNG or liquified natural gas; manufactures cryogenic equipment</td>
<td>FIBA has been actively involved in the conversion of diesel engines to operate on natural gas. It exports a variety of gas storage and compression products to the Middle East, South America, the Philippines, Korea and Indonesia.</td>
</tr>
<tr>
<td>8007 Chivvis Drive</td>
<td></td>
<td></td>
</tr>
<tr>
<td>St. Louis, MO 63123</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (314) 832-4500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Harold Guller, Chairman</td>
<td></td>
<td></td>
</tr>
<tr>
<td>FIBA Compressed Gas Eqt. Co.</td>
<td>Cylinder and tube trailers, high volume systems for gas storage and compression</td>
<td>FIBA has been actively involved in the conversion of diesel engines to operate on natural gas. It exports a variety of gas storage and compression products to the Middle East, South America, the Philippines, Korea and Indonesia.</td>
</tr>
<tr>
<td>97 Turnpike Road</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Westboro, MA 01581</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (617) 366-8361</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Frank H. Finn, President</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Future Fuels, Inc.</td>
<td>Prototypes of compressors, storage cylinders and conversion equipment</td>
<td>Future Fuels is researching activated carbon and zeolites for low pressure storage of natural gas. Small compressor designs are being developed as well.</td>
</tr>
<tr>
<td>500 Griswold Street</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Detroit, MI 48226</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (313) 256-5531</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Larry Engel, President</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Garretson Equipment Company</td>
<td>Mixers (six styles), adapter rings (25), idle controls, regulator packages (two)</td>
<td>The company manufactures engine products particularly suited for large gasoline engines.</td>
</tr>
<tr>
<td>Box 111, West Industrial Park</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mt. Pleasant, IA 52641</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (319) 385-2203</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keith Garretson, President</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### U.S. MANUFACTURERS/ASSEMBLERS OF CNG VEHICLE CONVERSION EQUIPMENT (continued)

<table>
<thead>
<tr>
<th>Company</th>
<th>Products</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Haskel, Inc.</td>
<td>Booster compressor packages</td>
<td>Holley has used its very broad knowledge of fuel delivery for all types of engines to design conversion carburetors and regulators for specific engines.</td>
</tr>
<tr>
<td>100 East Graham Place</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burbank, CA 91502</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (213) 843-4000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Willard Bizby, Marketing Mgr.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Holley Replacement Parts</td>
<td>Natural gas carburetors and regulators</td>
<td>Impeco has built its reputation on a carburetion system which has a few common components for all vehicle applications. These are then combined with customized components to overcome individual vehicle differences. It has 20 basic carburetor models and with various adaptors can convert 400 different types of vehicles. This is the largest CNG carburetion company in the U.S.</td>
</tr>
<tr>
<td>11955 East Nine Mile Road</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Warren, MI 48090</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (313) 497-4245</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Andrew Guria, VP-Marketing</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Impco Carburetion Inc.</td>
<td>Natural gas mixers, convertors and regulators</td>
<td></td>
</tr>
<tr>
<td>16916 Gridley Place</td>
<td>and industrial engines</td>
<td></td>
</tr>
<tr>
<td>Artesia, CA 90701</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (213) 860-6666</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Charles Sanders, Mktg. Mgr.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ingersoll-Rand</td>
<td>CNG compressors for all types of fleet</td>
<td>The company is developing a line of compressors specifically for CNG applications that will accept higher inlet pressures.</td>
</tr>
<tr>
<td>551077 Center Drive</td>
<td>applications</td>
<td></td>
</tr>
<tr>
<td>Charlotte, NC 28224</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (704) 527-0500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Larry Huser, CNG Product Mgr.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Micro-Motion, Inc.</td>
<td>Mass flow meters to measure gas and all types of fluid flow</td>
<td>Micro-Motion's meter can accurately measure CNG flow across all ranges of density and temperature. Readings are in kilograms, but can be converted to cubic feet, litres or other units. The company has exported many units to New Zealand, Canada and Italy.</td>
</tr>
<tr>
<td>7070-T Winchester Circle</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boulder, CO 80301</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (303) 530-0530</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jacob Beck, Int'l Sales Mgr.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Norwalk Compressor Co.</td>
<td>Nine different compressor designs for CNG</td>
<td>Norwalk is a leading supplier of CNG compressors with a line designed specifically for CNG. This is the new balanced-opposed compressor (&quot;Gas Patch&quot;). Norwalk has sold a considerable number of products in New Zealand, Canada as well as the U.S. It is researching equipment for public refueling stations, and now offers conversion kit assemblies in the U.S. market.</td>
</tr>
<tr>
<td>1321 Regal #340</td>
<td>refueling, including a vertical three-stage</td>
<td></td>
</tr>
<tr>
<td>Richardson, TX 75080</td>
<td>compressor and a vertical four-stage</td>
<td></td>
</tr>
<tr>
<td>Tel: (214) 644-9436</td>
<td>compressor</td>
<td></td>
</tr>
<tr>
<td>Paul Barron, Nat'l Sales Mgr.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nu-Fuel Industries Inc.</td>
<td>Assembles complete CNG conversion systems;</td>
<td>Nu-Fuel has done considerable research and development in both conversion systems and compressor designs. It manufactures one compressor line for home, farm and small fleet applications, and a second larger one for filling station use. Nu-Fuel has presented CNG seminars in Thailand, Bangladesh and Africa.</td>
</tr>
<tr>
<td>Box 220, Highway 43-N</td>
<td>manufactures two water-cooled compressors and</td>
<td></td>
</tr>
<tr>
<td>Loretto, TN 38469</td>
<td>a turbine flow meter with computer read-out</td>
<td></td>
</tr>
<tr>
<td>Tel: (800) 251-410C</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Robert Beckman, President</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Outboard Marine Corp.</td>
<td>Manufacturers and assembles a complete CNG</td>
<td>OMC is best known for its small CNG refueling compressor package.</td>
</tr>
<tr>
<td>P. O. Box 82409</td>
<td>conversion kit</td>
<td></td>
</tr>
<tr>
<td>Lincoln, NE 68501</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (402) 475-9581</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ron Stolly, Manager of Energy Programs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Company</td>
<td>Products</td>
<td>Comments</td>
</tr>
<tr>
<td>--------------------------------------------------</td>
<td>---------------------------------------------------</td>
<td>--------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Pressed Steel Tank Co. Inc.</td>
<td>36&quot; - 63&quot; CNG steel cylinders (10&quot; - 15&quot; inner diameter)</td>
<td>RIX offered the first refueling system for the home, and larger custom-built compressors are self-lubricating. Sales of larger compressors have been strong overseas, particularly in New Zealand.</td>
</tr>
<tr>
<td>1445 South 66th Street</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Milwaukee, WI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (414) 476-0500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nels H. Goodman, President</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RIX Industries, Inc.</td>
<td>Seven CNG compressor models for small, medium and large fleets, varying in size from 2 hp to 500 hp</td>
<td>The company uses technology developed for aerospace products to manufacture lightweight cylinders. Rosin and glass fiber is wrapped around the aluminum cylinders in a unique process to give them strength. Products are exported to Italy and England.</td>
</tr>
<tr>
<td>6460 Hollis Street</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emeryville, CA 94608</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (415) 658-5275</td>
<td></td>
<td></td>
</tr>
<tr>
<td>C. Frank DeWolf, President</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Structural Composites Industries, Inc.</td>
<td>Aluminum CNG cylinders (10&quot; outer diameter, 40&quot; length)</td>
<td>This is the oldest cylinder manufacturer in the U.S. and has a very large share of all cylinders used in CNG applications. Its cylinders are forged with a tapered wall.</td>
</tr>
<tr>
<td>325 Enterprise Place</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pomona, CA 91768</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (714) 594-7777</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Don Neff, Int’l Sales Mgr.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Taylor-Wharton Company</td>
<td>High pressure seamless steel cylinders in 2400 psi (six different lengths), 3000 psi (six) and 3600 psi (two)</td>
<td>Tri-Fuel is doing developmental work on small compressors, as well as electronic fuel injection systems. It designed and manufactures a digital fuel ignition system, and offers mechanic training and conversion equipment through a unique, self-selection catalog. It is exporting products to Canada and South America.</td>
</tr>
<tr>
<td>P. O. Box 1742</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Easton, PA 18042</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (215) 256-7271</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gus Meyer, President</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tri-Fuel, Inc.</td>
<td>Assembles CNG conversion kits, manufactures a digital spark advance</td>
<td></td>
</tr>
<tr>
<td>10165 Mammoth Drive</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Baton Rouge, LA 70814</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (800) 521-9071</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jeff Reidinger, Mktg. Dir.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vialle Carburetion Systems</td>
<td>CNG mixers and regulators</td>
<td></td>
</tr>
<tr>
<td>7042 Lampson Avenue</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Garden Grove, CA 92641</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tel: (714) 898-1884</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jeff Stern, Vice President</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
INFRASTRUCUTURE REQUIRED TO USE

COMPRESSED NATURAL GAS AS AN AUTOMOTIVE FUEL

DONALD I. HERTZMARK
Energy Technology Division
Asian Institute of Technology
Bangkok, Thailand
January, 1983
Compressed Natural Gas has been used as a motor fuel for over 30 years. Recent developments in liquid fuels supply have improved the prospects for using CNG in cars, trucks, and buses. This paper examines the infrastructure needs of a switch to CNG fuel. In particular, the refuelling and transport systems are described. Financial analysis is then performed; first on refuelling stations to determine selling prices for CNG under various alternatives, then on fleet vehicle and refuelling systems to determine rates of return on investment. The analysis shows that fleet use of CNG will be cheaper than diesel (US$ 0.20 - 0.25/l) and will yield a discounted cash flow rate of return of about 20% using conservative assumptions.
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1.0 INTRODUCTION AND SUMMARY

The infrastructure necessary to use compressed natural gas (CNG) as a transport fuel is easily divided into two aspects - gas transport and refuelling stations. In general, gas is transported through pipelines to the refuelling stations. The required reticulation area to make CNG viable depends on the volume and nature of the demand for CNG. For fleets refuelling at a central point, a limited pipeline system may suffice. Similarly, for point-to-point transport universal reticulation is unnecessary. However, for mass motoring applications a widespread pipeline system would be required to make CNG use convenient for the public.

A final element is the provision of parts and skills necessary to convert and maintain CNG vehicles. The relative scarcity of conversion and maintenance facilities in Thailand argues strongly for fleets rather than private cars at the present time.

Given the likely initial scope of CNG in Thailand, attention will be confined to regions already reticulated. Any startup program of modest size is unlikely to exert a demand for gas sufficient to justify further reticulation. For example, a fleet of 5000 trucks consuming approximately 30 gal. of diesel daily would use just 16 MMcfd if fully converted to CNG. Unlike New Zealand's situation where most of the North Island is reticulated, the gas transmission system in Thailand is limited to a trunk line from Rayong to Saraburi. Extensions or branches can be economically justified for industrial estates - possibly containing CNG fleets - but not for vehicular use alone.

Indeed, at natural gas prices of $4.00 per 10^6 BTU, could be justified for cars and light trucks as a petrol replacement only at high volume stations. The major economic justification for CNG lies in fleets which refuel at private stations.
In the present paper, I first describe the operation of refuelling station components. Then the costs for representative systems are given and finally breakeven prices for CNG are calculated for public and private refuelling stations. Finally, some safety policies, crucially affecting the CNG program are outlined.

Major Findings

- The components for CNG refuelling stations are readily available.
- CNG does not provide sufficient economic justification for extending a reticulation system.
- CNG must be seen as an additional use of existing gas transport facilities.
- CNG could substitute for petrol economically only if increased refuelling frequencies are acceptable.
- For truck, bus, and car fleets refuelling at a central station, CNG can save up to 50% of the cost of fuel.

2.0. FILLING STATIONS

Filling station systems are comprised of compressors to get the gas up to 160-180 bar, a storage system, a filling system and a meter. The size of the compressors and the amount of storage capacity vary with the demand characteristics facing the filling stations. A typical configuration is shown in Figure 2.1.

![Fig. 2.1] TYPICAL REFUELLING CONFIGURATION
2.1 SYSTEM DESCRIPTION

a. Compressors

Two main types of compressor systems dominate the current market. The first, primarily Italian-made, uses a reciprocating piston in an oil bath. These noisy and rather shaky systems appear to have poor reliability and owners voice dissatisfaction. Rotating compressors of U.S. manufacture are increasingly common in New Zealand and run more smoothly than the Italian units. They also take up less space than the reciprocating piston models.

For a small fleet of cars, an output of 25 to 60 cubic meters/hour (0.9 - 2.2 \(10^6\) BTU/hr.) of CNG (standard conditions) will be required. A vehicle fleet of 40 cars will require a 150 cu. meter/hour output. A truck fleet of 45 vehicles using CNG-Diesel at 6733 will require a compressor capacity of at least 220 M³/hr. (8.1 \(10^6\) BTU/hr.)

The size of the compressor depends heavily on the amount of static cylinder storage, the daily distribution of gas-offtake, and the suction pressure (the gas pressure in the gas utility pipeline serving the station). It is a savings in both capital cost (compressor, cylinders) and in operational expense (electricity) to be located on an industrial gas pipeline operated at, say, 5 bar rather than on a domestic pipeline at 1.5 bar. In Thailand, we can assume that all gas will be available from industrial pipelines only for the foreseeable future.

B. Static Storage Cylinders

In case of trickle-feed loading of a fleet of vehicles overnight, no static storage cylinders are required, and a smaller compressor can feed gas at the vehicle cylinder pressure (165 bar) than at the static storage cylinder pressure (200-245 bar). Such systems are used in the largest fleet applications in New Zealand.
However, in all other cases, where fast-feed is required, a substantial pressure difference is required between the compressor outlet and the air intake – e.g. private vehicles or taxi fleets. During fast-feed of a car cylinder, the pressure in the static storage cylinders will drop, releasing gas at high pressure into the feed-pipe. For efficient operation, fill times must be less than 2 minutes for passenger cars or taxis.

After the cylinder has been filled up to 165 bar, the compressor will keep running until the static storage cylinders reach 200 bar. Thus the amount of static storage (cascade capacity) determines the number of cars filled per hour and per day under fast-fill conditions.

Even a small cascade (See Fig. 2.2) will already have a positive effect in the time required to switch cars at the refill-point, and during continuous feeding it will reduce the wear and tear on the compressor due to the transient effects of stop-go operation of the compressor.

Some CNG stations are located on intercity highways, far from the natural gas pipelines. Caltex NZ operates a "Mother-Daughter" system in Marton, where they transport gas (200 bar) in large cylinders on a trailer from a mother-station on the pipeline to a daughter-station equipped with only a very large gas reservoir and a small compressor plus cascade. Gas is then sold at a slightly higher price (see fig. 2.3).

c. Fill-hose/metering

From the cascade a rigid steel pipe feeds the gas to a metering system. This may be a simple pressure gauge or a sophisticated digital mass flow meter. From there the gas flows through an overhead suspended flexible, rubber hose to the filling head. This head can only be applied to or removed from the refill nipple of the car-valve with the refilling valve in the rubber hose closed.
In case of the mechanical gas metering, the pressure in the car system is read from the pressure gauge before opening the refilling valve. After the car system attains 165 bar, the gas metering system automatically shuts off the gas flow.
Fig. 2.4: Fill-hose system for private fleet.

In the mechanical metering case, the amount of gas delivered is determined from a table: entering the water capacity, or volume of the car system (shown on the CNG certification plate on the car body), and the residual gas pressure in the car before refill, the table gives the volume of gas (under standard conditions: 15°, 1 bar).

Fig. 2.5: Typical Commercial Fill-Hose
In case of the digital metering system, no such human effort is required. The digital readout lists the amount of gas and/or price.

During fast refill from cascade, the turn-around time between two cars in the CNG station will be similar to that for a gasoline refill. Opening car's hood for hose connection and subsequent effort to read the table to determine consumption can increase filling times greatly.

2.2 Current Operating Conditions in New Zealand

In visits to numerous CNG-stations, the station owners appeared quite happy about their investments. Some regret not having invested more heavily, because the demand increased faster than expected with waiting lines forming, especially during peak commuting hours.

Many station owners have considered buying additional compressors for increased capacity, or enlarging their cascades for better peak demand performance.

Some stations add refill points to the same compressor/cascade system. However, quick performance under heavy demand requires that storage capacity be related to the number of fill points.

The mechanical metering system, besides being time-consuming and clumsy, may also give inaccurate readings. Pressure readings may be 5% distorted, and the tables are calculated for just one fill pressure and one specific ambient temperature. In addition, the friction of the fast-filled gas in the narrow pipes generates so much heat that the gas in the car cylinder will be hotter than ambient temperature, leading to an overestimation of gas sold. Under trickle fill conditions the amount of gas put into the vehicle cylinder will exceed that of fast-fill due to lower heating of pipes. Stations have found a disparity of up to 10% between the total of "sales" and the gas purchased from the utility company. The accuracy may be improved by using a programmable calculator instead of a gas
table for computing the gas delivered. The error due to the inaccurate pressure readings remains, however.

As a result of poor performance with the pressure difference method, digital meters are now invading the market strongly. Although rather expensive, they reduce turn-around time, allow automatic billing and improve accuracy. Many fleets choose to meter only the intake of gas at the compressor to avoid the expense of installing meters on each refill point.

Apart from the volumetric measurement, the value of gas depends on the composition (CH4/CO2/LPG/hydrocarbons). If the gas supplies come from different fields then either treatment of the gas to produce a standard cubic foot or allowance for the differences in energy contents must be made. This differential should be reflected in the price per cubic meter, or the gas should be sold per energy unit, and the "table" or digital readout expressed in energy units, rather than volume*.

2.3 Future Prospects

The main future prospect is the introduction of cheap home-type compressors. These would allow the trickle-fill of one or two cars overnight for domestic or light commercial use. In Australia, these units were predicted to reach the retail market with a US$ 1,500 price tag by the end of 1983.

If these small systems ever become economic, they would seriously threaten the viability of the present retail refill station. Note, however, that such a compressor would still fall below the cost effectiveness of an industrial trickle fill system. In addition, such a small compressor is only salable where gas is widely reticulated. Also, it would be rather... 

* Note that this problem is hardly unique to CNG. Both automotive diesel and gasoline may show significant variation that depends on additives (in the case of gasoline) or the "weight" of the crude feedstock (for diesel).
difficult to survey a large number of domestic appliances, more likely to be tampered by laymen than in the case of a station.

Small systems (domestic or small company fleets) also pose a taxing problem. Part of the road tax may be charged through fuel prices, and the gas utility will likely charge less for domestic gas than for a motor-fuel. Domestic filling may also pose a safety hazard as unsafe vehicles may not be inspected.

2.4 Economic of Refuelling

Filling stations show significant economies of scale. Overall, the economics of establishing a refuelling station for individual autos can be prohibitive. However, if the refuelling station is considered a necessary intermediate step in getting gas from the well to the engine, then the entire enterprise may pay off, economically if alternative transport fuels are expensive enough.*

a. Breakeven Analysis

Conversion of a station to CNG entails considerable expenses for machinery as well as extensive modification of the station. Direct costs for converting a station capable of handling up to 150 passenger vehicles/day on a regular basis total $140,000. The same capacity station could pump a greater volume of gas into a smaller number of large vehicles. The station shown in Table 1 can fill about 40-50 large trucks each day. Other associated costs including gas lines can cost as much as $10,000. Underlying such a cost breakdown are assumptions of nearby gas reticulation and light tariffs (<20%) on imported components.**

* This is akin to the oil industries' perennial problem of taking oil through high cost refinery to get the products to the public. Though the refiners often lose money, the companies consider this loss as a necessary business expense.

** New Zealanders reported that about 90% of the materials cost of a conversion is in imported parts.
To determine the average cost of filling a vehicle with 1.106 BTU of gas, I computed the amortization of the station conversion over 7.5 years at an interest rate of 10%. Table 2 gives the results of the calculations for 4 different types of refuelling stations: 2 public stations (low and high volume), and 2 private stations (one using fast fill, the other using trickle fill). The low volume public station can provide CNG at a cost lower than the current retail price of gasoline but exceeding that of diesel and LPG on a energy equivalence basis. High volume public stations can provide fuel more cheaply than gasoline or LPG but still higher than diesel. For high mileage gasoline or LPG consumers conversion to CNG should prove cost effective for those with access to gas.*

For private fleets CNG appears cost effective vis-a-vis diesel. Using conservative assumptions about backup compressor capacity and utilization factors, I found that fast fill stations could provide CNG for $4.00/lit. diesel equivalent when purchasing gas at $4.00/10^6 BTU. At a lower, industrial, rate of $3.50/10^6 BTU CNG will cost only $5.5/l.d.e.

The most favorable case involved slow fill of CNG-diesel trucks. I found that CNG could be provided for about $5/l.d.e., a 26% savings over high speed diesel.

* Note that CNG is widely used to replace gasoline in N.Z. However, the natural gas costs only about $3.30/10^6 BTU at the retail level.
### Table 1
**REFUELING STATION COSTS**

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost (tk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compressor (8.1 (10^6) BTU/hr. capacity)</td>
<td>60</td>
</tr>
<tr>
<td>Storage cylinders (40 bottles)</td>
<td>12</td>
</tr>
<tr>
<td>Dispensers (2 meter type or 10 pressure type)</td>
<td>11</td>
</tr>
<tr>
<td>Miscellaneous Materials</td>
<td>23</td>
</tr>
<tr>
<td>Subtotal, materials</td>
<td>106</td>
</tr>
<tr>
<td>Installation</td>
<td>30</td>
</tr>
<tr>
<td>Gas line</td>
<td>10</td>
</tr>
<tr>
<td>Startup expense, insurance</td>
<td>8</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>154</strong></td>
</tr>
<tr>
<td>(Additional Compressors for higher capacity)</td>
<td>46</td>
</tr>
<tr>
<td>Depreciation (10 year straight line)</td>
<td>10.6 (15.2)</td>
</tr>
</tbody>
</table>

**Notes:**
1. includes import duties on materials.
2. most commercial installations will have a backup compressor of lower capacity costing about $46,000.

**Source:** "The Use of Compressed Natural Gas in the Transport Sector," 1983.
TRANSPORT FUELS PRICING IN THAILAND

To discourage gasoline consumption, the Thai government taxes gasoline heavily resulting in a retail price of ฿12.60/liter for premium. Diesel and LPG, however, are slightly subsidized. The current diesel price of ฿6.8/liter amounts to $47/bbl. With current ex-refinery diesel prices of about $40/bbl, the retail price for diesel does not quite cover transport and marketing costs for some parts of the Thai market. LPG is subsidized largely for the residential/commercial fuel market and is priced lower than gasoline on an energy equivalence basis.

TRICKLE-FILLING

Additional savings can accrue to the owners of fleets if they can recharge the gas cylinders overnight using slow or trickle filling. At one large municipal fleet conversion in New Zealand, the city buses were all recharged at night or during the day between the morning and evening rush hours. Such a filling system shows significant advantages over higher speed systems utilizing storage. First, the compressor, running continuously, can achieve extremely high thermodynamic efficiency. This reduces the electricity consumption for a filling. Second, the optimum sizing of the compressor allows its amortization over a greater quantity of gas thereby lowering its cost per fill. Such a system could reduce fixed costs by as much as $.70/10^6 BTU and variable costs by $.25/10^6 BTU thereby reducing the effective liter price of diesel equivalent to about $0.23/l.
Table 2
BREAKEVEN ANALYSIS FOR REFUELLING STATIONS (ANNUAL BASIS)

<table>
<thead>
<tr>
<th></th>
<th>Public (cars, light trucks)</th>
<th>Private (trickle fill)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>low volume</td>
<td>high volume</td>
</tr>
<tr>
<td>Gas sold (10^6 BTU)</td>
<td>5,939</td>
<td>11,786</td>
</tr>
<tr>
<td></td>
<td>30,153</td>
<td>39,160</td>
</tr>
<tr>
<td>Fixed Costs¹ (depreciation)</td>
<td>30,153</td>
<td>39,160</td>
</tr>
<tr>
<td></td>
<td>30,153</td>
<td>39,160</td>
</tr>
<tr>
<td>Variable Costs²</td>
<td>6.47</td>
<td>5.52</td>
</tr>
<tr>
<td></td>
<td>6.47</td>
<td>5.52</td>
</tr>
<tr>
<td>Profit</td>
<td>2568</td>
<td>3335</td>
</tr>
<tr>
<td></td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Sales Price</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10^6 BTU</td>
<td>11.98</td>
<td>9.13</td>
</tr>
<tr>
<td></td>
<td>11.98</td>
<td>9.13</td>
</tr>
<tr>
<td>1 diesel equiv³</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.46</td>
<td>0.35</td>
</tr>
<tr>
<td></td>
<td>0.46</td>
<td>0.35</td>
</tr>
<tr>
<td></td>
<td>(0.40)</td>
<td>(0.30)</td>
</tr>
<tr>
<td></td>
<td>(0.40)</td>
<td>(0.30)</td>
</tr>
<tr>
<td>R⁴</td>
<td>10.6</td>
<td>8.0</td>
</tr>
<tr>
<td></td>
<td>(9.1)</td>
<td>(6.9)</td>
</tr>
</tbody>
</table>

Notes: 1. System life = 7.5 years, 2 compressors at all but low volume public station, no storage tanks at trickle fill station.
2. Includes gas, electricity, maintenance, insurance. At private stations lower figure assumes industrial gas price of $3.50/10^6 BTU.
3. Figures in parenthesis are in liter of gasoline equivalent.
4. Current diesel and gasoline prices are $6.8 and $12.6/1,

Sources: Calculated from N.Z. costing and construction data.
b. Rate of Return Analysis

In order to determine whether conversion to a CNG fleet offers an adequate return on investment, I calculated the discounted cash flow rates of return (dcfror) for private fleets. Included in the problem were the vehicle systems and refuelling systems. Allowances were made for periodic renewal of vehicles and compressors (see Table 3).

At gas prices of $4.00/10^6$ BTU, a company converting its fleet to a trickle fill system could earn a dcfror of 21% using short and long term interest rates of 10 and 14%, respectively. Normal fast fill systems were found to be uneconomic (dcfror = 8.8%) under the assumptions used here.

If companies could take advantage of industrial gas prices of $3.50/10^6$ BTU then both fast and trickle fill systems prove economic. With rates of return of 17.5% and 25.7%, respectively, the fast and trickle systems compare favorably with other transport investments.

The results are more sensitive to variations in gas prices than in interest rates. From Table 3, it appears that trickle fill systems are economic under both gas prices but fast fill only if gas prices are $3.50/10^6$ BTU. When interest rates were varied the results changed, though not radically. Higher long term interest rates (21%) and short term ones (14%) raise the rates of return by about 20% indicating that variable, not fixed, costs are the keys to achieving a good return.
TABLE 3

RATES OF RETURN FOR CNG FLEETS

<table>
<thead>
<tr>
<th>Gas Price/10^6 BTU</th>
<th>Normal fill</th>
<th>Trickle fill</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.50</td>
<td>17.5</td>
<td>25.7</td>
</tr>
<tr>
<td>4.00</td>
<td>8.8</td>
<td>21.0</td>
</tr>
</tbody>
</table>

Assumptions:
- Short term rate = 10%
- Long term rate = 14%
- Minimum reinvestment = $50,000
- Vehicles renewed every 5 years
- Compressors replaced in 8th year

Source: Tables 1 and 2

3.0 Gas Transport

With its low energy density, natural gas has generally been efficiently transported only by pipelines. Other forms of transportation involve pressurization/liquefaction with attendant high capital and operating costs.

3.1 Pipelines

A 4" diameter pipeline may cost about $6/ft. (18.60/M) over level terrain. Thus a 1 km pipeline can cost almost $20,000 to install. Such a pipeline can carry enough gas to fuel 500-750 vehicles daily. A 2" line with only 1/4 the capacity of the 4" line will cost about half as much to purchase and install. The limit on pipeline expenditure by a fleet will be
about $20-25,000. Thus, an individual fleet could construct 1-2 km. of pipeline. Expenditures of more than $25,000 would make the entire conversion marginal.

The density of use dramatically affects transport costs. A 10 km. pipeline costing $186,000 can provide economic gas supplies for a CNG fleet if most of the gas is used industrially for process heat.

3.2 Trucks

For distances up to 40 km. Caltex New Zealand has put CNG into specially configured tractor trailers. The transport effort was designed primarily to make possible long distance driving and market expansion for CNG as the costs are prohibitive for diesel substitution.
4.0 CONCLUSIONS

- CNG offers a competitive fuel for fleets now using diesel.

- CNG systems can be easily assembled from known sources using available technology.

- Substitution of CNG for Gasoline and LPG is only economic for high volume refuelling stations.

- The spread of CNG is limited largely by the reticulation system.

- CNG use cannot by itself justify investments in pipelines more than 1 km. long so use is likely to be limited to current gas users or those along the truck line.

- Truck transport of CNG is justifiable only by the reliance on large refuelling stations on an existing gas line.

- The costs of using CNG vary directly with the volume of gas used and the price of gas while returns vary inversely.

- CNG is most attractive for large fleets using slow fill.
Mother-Daughter Filling Stations

In New Zealand, as elsewhere, it is uneconomic to reticulate the entire country, particularly in relatively sparsely populated areas. One solution tried in New Zealand is the mother-daughter system of Caltex. Under this scheme, a "mother" station with large compressor and tank capacity for 72-108,000 ft³ will be used as storage for filling tractor-trailers containing 36,000 ft³ capacity. These trucks then deliver gas to the "daughter" station (<36,000 ft³) and return to the Mother station for a refill for some other daughter station*.

The heavy duty compressors and large storage tanks entail considerable expense. Data from Caltex show "Mother" station costs in excess of $350,000 plus another $225,000 for the special tractor trailer (including duties). "Daughter" station costs should not exceed $100,000, a savings over conventional stations offset by higher costs for the mother station and for delivery.

Overall, the "Mother-Daughter" system represents a higher cost approach to filling vehicles than would be the case in a fully reticulated area. However, all of the components of the system are fully portable. As a result, companies may use the mother-daughter set up as a means of advancing the marketing area in the face of insufficient reticulation.

* Note that large filling station may dispense more than 36,000 ft³/day. In rural areas, however, a refill every day or every other day would appear sufficient.
References


N.Z. Govt., Ministry of Energy: Various internal memoranda including:

- "CNG Conversion Kit Sales"
- "CNG for Fleet Vehicles"
- "National Economics of CNG"
- "Summary of Government Incentives and Measures for CNG"
- "Public CNG Refuelling Stations"


Dual-Fuels, Ltd., various promotional and informational brochures.
Appendix: Safety Regulations for the CNG System

In order to assure a safe operation of CNG stations, New Zealand, Italy, and the U.S.A. all regulate various aspects of CNG use. Overall, the U.S. system is the most lenient while the Italian system is the strictest. The following information details some of the safety standards common to CNG programs.

Equipment:
- identification of each component with manufacturers’ I.D. number and part number.
- adoption of internationally recognized standards of safety and performance; adaptation of standards where appropriate – e.g. vehicle mixers.
- periodic inspections and tests of individual components, especially storage cylinders.
- designation of a single government agency responsible for vehicle and inspection.

Vehicle Systems:
- mandatory initial (roadworthiness) inspection of entire system
- periodic reinspections and tests
- adoption of collision survival standards

Refuelling Stations:
- standardized station layout and establishment of minimum space requirements for compressors and storage systems
- crash and explosion protection for compressors and cylinders

Manpower:
- mandatory training programs for installers
- subsequent authorization of approved installers
- periodic updating of technical skills.
The Decision is to go with CNG or LPG

For many nations with natural gas resources, CNG and LPG represent mutually exclusive vehicular alternatives. Perhaps the most basic aspect of the decision hinges on the properties of the gas itself. Very "dry" gas, that with little liquids content, will have less energy per cubic meter than will gas which is richer in liquids. Even under compression, such gas will deliver low travel range relative to other fuels. On the other hand, without liquids, the gas serves primarily as a boiler fuel, its lowest value use. The LPG fraction is thus useful even in CNG applications where it adds range to a given storage cylinder. Given availability of the LPG fraction, the second criterion should establish whether there exist "high valued uses for these products. Generally, unless the country has a developed chemical industry, LPG markets will fall short of production potential. In such cases, the easy portability and relative cheapness of setting up the LPG network can militate in favor of LPG.

From a world market standpoint, great volumes of LPG from the Arabian/Persian Gulf should exert a moderating effect on world LPG prices for some time. This may add to the attractiveness of LPG since demand peaks can always be met from world markets. A decision to favor CNG over LPG, then, requires some combination of the following factors:

1. dry gas.
2. alternative uses for gas liquids.
3. existing gas reticulation system to cover significant transport area for CNG users.
4. lack of prior commitment to LPG.

* for example. Thai LFG demand is met primarily from barge cargoes in the Gulf of Thailand.
New Zealand's Approach to Incentives

1. Fuel Prices:

Public statement that any changes in fuel taxation will not disadvantage CNG relative to imported fuels and that the price of CNG will not be more than about half the price of petrol.

2. Depreciation:

Retrofit conversions of business vehicles are eligible for depreciation as capital expenditure. Factory installers can write off $900 (1 cylinder) to $1200 (2 cylinders) for each conversion.

3. Grants to Consumers:

Retrofit: rebate of $150 to suppliers of CNG kits - must be passed on to consumers.

Factory: grant totals $65 - $70, depending upon vehicle size. The $150 grant for the kit is in addition to the factory grant. The latter is designed to offset any additional sales taxes on the new vehicle due to CNG equipment.

4. Grants to Refuelling Stations:

Up to 25% of the value of qualifying components will be given to stations (e.g. compressors, cascades, meters, etc.)

5. Loan Schemes:

Loans of $3700 up to $370,000 are available at subsidized interest for individuals, organizations, and refuelling stations wishing to install CNG equipment, provided the system economics is favorable. The loan scheme was designed to permit CNG users, mechanics, and refuelling stations to adopt the products at a more rapid rate.

6. Publicity:

The Ministry of Energy is a member of the CNG publicity committee and in addition publishes a wide range of brochures on CNG.
THAILAND - UNITED STATES
NATURAL GAS UTILIZATION
SYMPOSIUM

February 7-11, 1984

THE PRODUCTION, USE AND ECONOMICS
OF METHANOL

By

Bert W. Struth
Chem Systems Inc.
THE PRODUCTION, USE AND ECONOMICS
OF METHANOL

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Chem Systems Inc.

Methanol represents a key alternative use for natural gas in Thailand as well as in other gas producing areas. This paper will consider the principal factors which impact investment decisions. These include

- Global and regional markets
- Product pricing
- Production and investment costs for specific locations
- Plant size
- Degree of product export
- Shipping costs for exports

Demand

Current global methanol demand is almost entirely for chemical applications. This is indicated in Table I. These uses will increase modestly. Growth will be led by methanol demand for acetic acid manufacture due to the preferred economics of methanol carbonylation by comparison to alternative techniques. Formaldehyde, by far the largest current market for methanol, will continue to grow in line with forest products, the most significant formaldehyde end-use market.
The fastest growing methanol markets will be for fuel-related uses such as for MTBE, an effective gasoline octane booster. Direct blending with gasoline is a potentially huge market, but will develop slowly due to concerns about performance as well as the short-term outlook for soft fuel markets. These outlets could account for about forty percent of total methanol demand by 1995.

Current and forecast methanol demand (Table II) is predominantly in the United States, Western Europe, Eastern Europe and Japan. These geographic areas represent about 90 percent of global demand. By 1995, these regions will still be dominant with 75 percent of the total global demand.

The United States is currently the largest market, representing 30 percent of the total. In the future, there will be a transition to greater utilization of methanol in fuel applications. This trend will be part of a long-term strategy to diversify energy services. Initially, imports will supply this market. Coal will represent a potential domestic raw material, but government subsidies will be required before these large capital-intensive projects will be built.
TABLE II
GLOBAL METHANOL DEMAND
(Thousand Metric Tons)

<table>
<thead>
<tr>
<th></th>
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<td>123</td>
<td>190</td>
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<td>41</td>
<td>43</td>
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<td>457</td>
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<td>4,995</td>
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<td>3,400</td>
<td>5,000</td>
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<td>7.5</td>
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<td>135</td>
<td>400</td>
<td>780</td>
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<td>13.9</td>
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<td>200</td>
<td>555</td>
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<td>202</td>
<td>230</td>
<td>330</td>
<td>445</td>
<td>6.3</td>
</tr>
<tr>
<td>Middle East/Africa</td>
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<td>145</td>
<td>190</td>
<td>720</td>
<td>1,000</td>
<td>26.0</td>
</tr>
<tr>
<td>Other</td>
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<td>75</td>
<td>97</td>
<td>120</td>
<td>170</td>
<td>6.4</td>
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<td>14,985</td>
<td>21,655</td>
<td>23,800</td>
<td>7.5</td>
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<tr>
<td>Fuel-related uses, %</td>
<td>6</td>
<td>8</td>
<td>18</td>
<td>31</td>
<td>40</td>
<td></td>
</tr>
</tbody>
</table>

Western Europe is the world's second largest methanol market. Growth will also be largely in fuel markets, with methyl tertiary butyl ether (MTBE) the most significant fuel-related use over the period. Methanol blends in gasoline have been tested in Sweden, Austria and West Germany, and some utilization is expected by 1990. Lower gasoline demand will make methanol demand for fuels less important in Western Europe than in the United States.

Eastern Europe and the U.S.S.R. make up the third largest methanol market. Demand has grown 8 percent per year during the 1970s, mostly for formaldehyde, DMT and solvent uses. In addition to traditional markets, the Soviets are working on the use of methanol as a gasoline substitute. A single-cell protein plant is also possible by 1990.
Japan is the fourth largest methanol market and the major target market for exporting projects in the Pacific. Fuel markets are possible by 1990, but will likely be in lower value utility applications.

Other markets, shown in Table II, are much smaller. Some projects are being developed in these regions as dedicated fuels projects. One such project is that planned by the Government of New Zealand. Methanol from two 2,000 metric ton per day methanol plants will be converted to synthetic gasoline via the Mobil process. The other dedicated fuels project is a methanol from coal plant being planned in South Africa. The objective is to use methanol as a blend with diesel fuel. These projects will dramatically change methanol demand in these countries, but will be based on domestic supply. A geographic breakdown of fuel-related demand is summarized in Table III.

### TABLE III

**GLOBAL FUEL-RELATED METHANOL DEMAND**

(Thousand Metric Tons)

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
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<td>United States</td>
<td>450</td>
<td>1,815</td>
<td>2,460</td>
<td>3,720</td>
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<td>305</td>
<td>480</td>
<td>1,000</td>
<td>1,750</td>
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<td>Japan</td>
<td>-</td>
<td>-</td>
<td>250</td>
<td>600</td>
</tr>
<tr>
<td>Canada</td>
<td>1</td>
<td>170</td>
<td>400</td>
<td>500</td>
</tr>
<tr>
<td>Mexico</td>
<td>20</td>
<td>50</td>
<td>0</td>
<td>200</td>
</tr>
<tr>
<td>Middle East/Africa</td>
<td>-</td>
<td>-</td>
<td>200</td>
<td>800</td>
</tr>
<tr>
<td>Eastern Europe</td>
<td>70</td>
<td>200</td>
<td>1,000</td>
<td>2,500</td>
</tr>
<tr>
<td>New Zealand</td>
<td>-</td>
<td>-</td>
<td>1,300</td>
<td>1,300</td>
</tr>
<tr>
<td>Other Pacific</td>
<td>-</td>
<td>50</td>
<td>60</td>
<td>90</td>
</tr>
<tr>
<td>Total</td>
<td>845</td>
<td>2,765</td>
<td>6,670</td>
<td>11,460</td>
</tr>
</tbody>
</table>

**Driving Force for Fuel-Related Demand**

Although methanol markets are being developed in a number of fuel-related applications, it will only displace conventional fuels if there is a strong economic driving force for its use.
Gasoline Blending

The most important near-term market for methanol is as a high octane blending component in gasoline. Methanol requires care in handling because of its sensitivity to moisture. It is also corrosive to conventional automobile components at concentrations above about 10 percent. However, methanol is currently being blended commercially at a level of 2-3 percent in Europe and 5-10 percent in the United States. The blending levels of methanol in Europe are based on an economic assessment by refiners. In the United States, the Environmental Protection Agency has set limits, which are higher than those used in Europe based on its authority under the Clean Air Act. The ultimate methanol blending level that will be allowed is expected to correspond to about 3.5 percent oxygen level in the near term and 5 percent oxygen beyond 1990. Use of a higher alcohol is required in the opinion of Chem Systems to mitigate potential problems with methanol. For this reason, methanol blending levels will be limited to about 5-8 percent over the forecast period.

The economic driving force for the use of methanol in the United States as a gasoline blending component is shown in Figure 1 for refiners with different octane improvement costs. The value of methanol in gasoline exceeds its current price. Put in terms of the refiners, methanol can reduce the cost of producing gasoline by 0.7-1.0 cents per gallon in an efficient refinery for which octave costs are incremental costs of catalytic reforming. Gasoline costs for gasoline, blenders or low conversion refiners are typically reduced by 1.5-2 cents per gallon. These are very significant cost savings today and in the future.

There are costs associated with introducing methanol into a gasoline distribution system. However, these are primarily start-up costs. For a major refiner, they are estimated to be less than $1 million, which would be recovered in cost savings in a matter of months.
FIGURE 1
METHANOL VALUE VS. COST FOR DIFFERENT REFINERS
(Cents Per Gallon)

BASIS: 1:1 MeOH: TBA
TBA at Gasoline Blending Value
3.5 PERCENT TOTAL OXYGEN
Nevertheless, the gasoline blending market is developing slowly. Octane capabilities in the industrialized regions are generally more than adequate to meet forecast demand. Automobile producers, who have nothing to gain from the use of methanol and fear problems with warranties, are generally negative about methanol/gasoline blends.

In the United States, the only major integrated refiners to adopt the use of methanol are ARCO and Sun. Moreover, they are using methanol on a regional basis due to limitations on fungibility and movements through common carrier pipelines. Technical problems with methanol such as scale pickup and storage tank corrosion are solvable as demonstrated by ARCO and Sun experience. This is a highly fractured market and considerable selling effort is required to achieve forecast demand. Forecast methanol demand, however, corresponds to less than one percent of the total gasoline demand throughout the forecast period.

In Western Europe, where the refining industry is highly concentrated, low level methanol blends are used widely in West Germany and have been introduced in Italy. Scandinavian countries are expected to adopt low level blends in the near future. By 1990, all West European gasoline is expected to be at low lead levels and the use of methanol will be widespread.

The only other significant gasoline blending market anticipated in the forecast period is in Canada. The likely reduction in lead levels and availability of low-cost methanol will provide favorable economics for its use. Refiners will be able to meet anticipated lead limits at current costs without additional capital expenditure, and methanol producers will achieve prices comparable to or higher than netbacks on methanol exports.

Cosolvent alcohol availability is a serious obstacle to the development of this market. The most economic cosolvent alcohol is tertiary butyl alcohol. TBA is available from only one producer, ARCO. The other C3 and C4 alcohols are priced at almost twice the price of TBA. However, additional cosolvent alcohol supply is possible through:
Texaco becoming a PO/TBA producer.

Hydration of C₃ to C₅ olefins in refineries.

Commercialization of methanol synthesis catalyst coproducing higher alcohols.

**Neat Methanol**

The use of neat methanol as a transportation fuel requires vehicles with engines designed for its use and compatible materials of construction. It also requires suitable fuel distribution systems. These are sizable structural impediments to the development of this market. Methanol price is expected to be 60-65 percent of gasoline price on a volumetric basis over the forecast period. After accounting for the lower volumetric energy content of methanol, the savings in fuel cost with methanol are less than 10 percent. This does not provide much economic incentive to develop this application. However, neat methanol markets are forecast to develop by the latter part of the forecast period in Canada, the United States and possibly other gas-rich and crude-short countries such as New Zealand, Thailand and Malaysia.

In the United States, it is estimated that a government subsidy on the order of 50 million dollars will be required to launch neat methanol. Government aid at this level is a fraction of the prospective price guarantees for synthetic fuel plants. The forecast assumes that centrally fueled fleets rather than private vehicles will adopt methanol and that 10 percent of these fleets are converted to methanol by 1995.

**Diesel Substitute**

Although methanol has a poor cetane rating, it is feasible to use methanol in modified engines as a diesel substitute. However, tests to date indicate that mileage achieved with methanol is only 40 percent of diesel fuel. For this reason, the economics of methanol use as a diesel substitute will not be favorable, except perhaps in gas-rich and crude-poor regions.
Other Fuel Markets

The Mobil synthetic gasoline process, which produces methanol as an intermediate is being commercialized in New Zealand and, if successful, may be duplicated in other gas-rich and crude-poor countries. However, these will be captive market outlets and will not likely impact the global methanol business.

Methanol is a clean-burning fuel for power generation but will have to compete with natural gas or distillate fuels. In most cases, this application will not be economic, and power generation is not expected to be a significant market for methanol.

Supply

Effective global methanol capacity, summarized in Table IV, is derived from nameplate capacities by estimating operating efficiency attainable in different regions of the world.

Effective capacity exceeded demand by over 3 million metric tons in 1982. The average operating rate for the year was 80 percent of effective capacity which was low by comparison with historical levels. However, by 1985, the global excess capacity will approach 6 million metric tons per year. High cost capacity in Japan, Taiwan and Korea are not included in the surplus since it is uncompetitive.

Chem Systems has forecast actual supply profiles for each region of the world required to achieve a balance between demand and supply. Results of this analysis are summarized in Table V. The rationalization of capacity which has begun in Japan and Western Europe will continue at rather dramatic rates. At least 1 million metric tons of U.S. methanol capacity will also shut down in the near future. Other significant shutdowns in Taiwan and Korea have already occurred.
## TABLE IV

**GLOBAL METHANOL EFFECTIVE CAPACITY**
(Thousand Metric Tons)

<table>
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<td>Operating Days per Year</td>
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<td></td>
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<tr>
<td>ASEAN group</td>
<td>300</td>
<td>30</td>
<td>30</td>
<td>530</td>
<td>930</td>
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<tr>
<td>Japan</td>
<td>340</td>
<td>1,120</td>
<td>1,120</td>
<td>500</td>
<td>500</td>
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<tr>
<td>Australia/New Zealand</td>
<td>350</td>
<td>600</td>
<td>600</td>
<td>480</td>
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<td>Other Asian</td>
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<td>3,000</td>
<td>3,150</td>
<td>5,300</td>
<td>5,800</td>
</tr>
<tr>
<td>United States</td>
<td>340</td>
<td>4,250</td>
<td>4,680</td>
<td>5,000</td>
<td>5,000</td>
</tr>
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<td>Western Europe</td>
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<td>2,600</td>
<td>2,000</td>
</tr>
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<td>Eastern Europe</td>
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<td>2,700</td>
<td>3,150</td>
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</tr>
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<td>Canada</td>
<td>330</td>
<td>450</td>
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<td>1,900</td>
<td>1,900</td>
</tr>
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<td>Central &amp; South America</td>
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<td>175</td>
<td>575</td>
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<td>3,600</td>
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<td><strong>Total</strong></td>
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<td><strong>14,255</strong></td>
<td><strong>20,755</strong></td>
<td><strong>24,500</strong></td>
<td><strong>31,290</strong></td>
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## TABLE V

**GLOBAL METHANOL SUPPLY FORECAST**
(Thousand Metric Tons)

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<td>1,800</td>
<td>2,920</td>
<td>4,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>11,161</strong></td>
<td><strong>11,181</strong></td>
<td><strong>15,075</strong></td>
<td><strong>21,555</strong></td>
<td><strong>23,800</strong></td>
</tr>
</tbody>
</table>
Supply/Demand

Current and forecast regional methanol net trade resulting from the demand and supply forecasts is shown in Table VI. The United States will join Western Europe and Japan as a major methanol importer by 1985.

Taiwan, Korea, and the Indian Subcontinent, called "Other Asian" countries in Table VI, will be the only other significant importing region throughout the forecast period. Saudi Arabia will become the largest methanol exporter by 1985, displacing Canada. The Middle East will remain the largest export region during the forecast period. In the near term the other major export regions will be Eastern Europe and the ASEAN group (Indonesia, Malaysia, Philippines, Singapore and Thailand). A desire on the part of importing regions to diversify supply will most likely result in growing exports by Central and South America, beginning with Trinidad and Tobago in 1984.

### TABLE VI

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>United States</td>
<td>345</td>
<td>(1,285)</td>
<td>(1,550)</td>
<td>(3,190)</td>
</tr>
<tr>
<td>Western Europe</td>
<td>(700)</td>
<td>(1,665)</td>
<td>(2,055)</td>
<td>(4,190)</td>
</tr>
<tr>
<td>Japan</td>
<td>(485)</td>
<td>(975)</td>
<td>(1,530)</td>
<td>(2,170)</td>
</tr>
<tr>
<td>Eastern Europe</td>
<td>150</td>
<td>745</td>
<td>1,255</td>
<td>1,950</td>
</tr>
<tr>
<td>Australia/New Zealand</td>
<td>(41)</td>
<td>257</td>
<td>300</td>
<td>300</td>
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<tr>
<td>ASEAN group</td>
<td>(50)</td>
<td>377</td>
<td>730</td>
<td>2,000</td>
</tr>
<tr>
<td>Other Asian</td>
<td>(127)</td>
<td>(257)</td>
<td>(220)</td>
<td>(350)</td>
</tr>
<tr>
<td>Canada</td>
<td>550</td>
<td>1,000</td>
<td>1,020</td>
<td>1,400</td>
</tr>
<tr>
<td>Mexico</td>
<td>32</td>
<td>0</td>
<td>0</td>
<td>215</td>
</tr>
<tr>
<td>Central &amp; South America</td>
<td>(72)</td>
<td>290</td>
<td>770</td>
<td>1,255</td>
</tr>
<tr>
<td>Middle East/Africa</td>
<td>330</td>
<td>1,610</td>
<td>2,200</td>
<td>3,000</td>
</tr>
<tr>
<td>Other</td>
<td>(75)</td>
<td>(97)</td>
<td>(120)</td>
<td>(170)</td>
</tr>
<tr>
<td>Net surplus/(deficit)</td>
<td>(83)</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
World Trade

Net interregional methanol trade is expected to increase dramatically from 1.6 million metric tons in 1982 to 4.3 million metric tons in 1985 to 6.3 million metric tons in 1990 and 10 million metric tons in 1995. These estimates exclude interregional trade and swaps, whereby a country may import methanol from one source and export it to another location, so actual trade is likely to be even higher.

The anticipated global trade pattern for 1985 is shown in Figure 2. The major exporting regions will be Western Canada, the Middle East, and Eastern Europe. Other exporting regions will include Trinidad, New Zealand, and the ASEAN group. Western Europe will be the largest methanol importing region, with supplies primarily from North Africa, the Middle East and Eastern Europe. The United States is expected to be a major methanol importer from Western Canada, Trinidad and the Middle East. Japan will continue to be the country most dependent on imports. Supplies will come, in order of priority, from the Saudi joint venture and then from New Zealand, Canada, and Malaysia. Other significant import markets will be Korea, Taiwan, and India. Longer term trade forecasts show a continuation of the 1985 pattern with the addition of other suppliers.

Pricing

The outlook for continued methanol oversupply will maintain severe pressure on methanol prices. U.S. methanol prices are forecast to remain at the cash costs of the marginal domestic producer. Natural gas costs to these producers will be comparable to residual fuel oil prices.

The growing number of export-oriented methanol producing regions is expected to result in the convergence of methanol prices in major markets such as the United States, Western Europe and Japan. Each producer will strive to export to locations which yield the maximum netback realization. Regional methanol prices and netbacks to major producers in 1983 and 1985 are shown in Figures 3 and 4, and methanol price forecast to 1995 is summarized in Table VII. A high and low forecast is presented in addition to the most likely estimate.
FIGURE 2

GLOBAL METHANOL EXPORT TRADE
1985
(THOUSAND METRIC TONS)
FIGURE 3

GLOBAL METHANOL PRICING AND NETBACKS
1983
(DOLLARS PER METRIC TON)

130 (J)
105 (WE)
135 (WC)
80 (GC)
180
180
FIGURE 4

GLOBAL METHANOL PRICING AND NETBACKS
1985

(DOLLARS PER METRIC TON)

[Map showing global methanol pricing and netbacks in 1985]

CHM SYSTEMS INC.
PROJECT NO. 8240 DATE
TABLE VII
METHANOL PRICE FORECAST
(Dollars per Metric Ton)

<table>
<thead>
<tr>
<th></th>
<th>U.S.</th>
<th>Europe</th>
<th>Japan</th>
<th></th>
<th>U.S.</th>
<th>Europe</th>
<th>Japan</th>
<th></th>
<th>U.S.</th>
<th>Europe</th>
<th>Japan</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>210</td>
<td>230</td>
<td>230</td>
<td>Most Likely</td>
<td>197</td>
<td>220</td>
<td>220</td>
<td>Low</td>
<td>170</td>
<td>180</td>
<td>170</td>
</tr>
<tr>
<td>1985</td>
<td></td>
<td></td>
<td></td>
<td>1990</td>
<td>270</td>
<td>280</td>
<td>270</td>
<td>1995</td>
<td>365</td>
<td>375</td>
<td>365</td>
</tr>
<tr>
<td>1990</td>
<td>320</td>
<td>330</td>
<td>320</td>
<td></td>
<td>240</td>
<td>240</td>
<td>240</td>
<td></td>
<td>330</td>
<td>330</td>
<td>330</td>
</tr>
<tr>
<td>1995</td>
<td>440</td>
<td>450</td>
<td>440</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The high forecast is based on the high side energy forecast presented in Table VIII. The impact on methanol price of higher crude price will be to increase natural gas feedstock costs in the industrialized countries such as the United States and Western Europe.

TABLE VIII
CRUDE SCENARIOS - OPEC MARKER CRUDE $/BBL

<table>
<thead>
<tr>
<th></th>
<th>High Crude</th>
<th>Most Likely Crude</th>
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<tbody>
<tr>
<td>1983</td>
<td>29</td>
<td>29</td>
</tr>
<tr>
<td>1985</td>
<td>34</td>
<td>29</td>
</tr>
<tr>
<td>1990</td>
<td>48</td>
<td>38</td>
</tr>
<tr>
<td>1995</td>
<td>67</td>
<td>50</td>
</tr>
</tbody>
</table>

A worst case price forecast assumes the fuel-related markets, which account for 60 percent of forecast growth, do not develop. In this case, an additional 1.5 million metric tons of methanol capacity would be forced to close in the United States and the remaining producers, highly integrated into downstream methanol derivatives with captive sources of natural gas, would produce methanol at a loss, using profits from
derivatives to maintain overall business center profitability. However, even if demand is lower than forecast, continued methanol production at less than cash costs over a sustained period of time would be unlikely, and prices are unlikely to be as low as anticipated in this worst case scenario.

What is likely, however, is the development of a two-tiered pricing structure between chemical and fuel uses. Although the markets are distinct, such two-tier pricing would be extremely hard to maintain without external factors. However, tariff policies in the United States and elsewhere, which apply duties to methanol imports for chemical uses but not for fuel applications, are likely to play a key role in maintaining a 10-20 percent higher price for methanol use in chemical markets rather than fuel-related uses.

New methanol plants which will be built in the next 5 to 10 years are virtually all expected to be built in gas-rich regions. Methanol from these facilities will have to displace existing supplies since projects already underway are sufficient to meet demand until the late 1980s. Methanol from coal does not appear economically viable during the forecast period without government subsidies.

These plants, which represent the incremental supply, have natural gas costs set by the government since the natural gas feedstock has no clear-cut alternative market value. Methanol, ammonia, and LNG are the practical alternative uses.

United States

The marginal producer of methanol is expected to be a U.S. producer which is able to obtain natural gas at prices comparable to those achieved by utilities. These gas prices will be comparable to the Btu equivalent of medium sulfur fuel oil at the burner tip in major market areas.
Many U.S. methanol producers are operating near their cash costs of production. Even with anticipated shutdowns, surplus methanol capacity will continue to put pressure on methanol pricing in 1985 to the point that the methanol price is expected to be close to the cash costs of the marginal producer.

On this basis, the 1985 U.S. methanol price is expected to be $197 per metric ton. At this price, methanol netbacks to Canada on sales to the Gulf Coast would just cover cash costs. Shipping costs for Alberta consist of two distinct parts: rail to Vancouver and tanker to the Gulf Coast.

However, Canadian methanol exports to the U.S. West Coast or mid-continent would be more attractive, netting back $137 per metric ton. Methanol netbacks to Saudi Arabia in 1985 vary from $90-121 per metric ton depending upon whether the methanol is shipped in a dedicated 30 thousand ton vessel or via a parcel tanker in 5-10 thousand ton lots. This is a crucial factor in the profitability of supplying methanol from Saudi Arabia. While netbacks on exports from Saudi Arabia to the U.S. are only modestly attractive, netbacks from sales to Japan and Western Europe will be $150-185 per metric ton based on large vessels. Plant storage is adequate to serve as a terminal for shipping from the Middle East.

In 1990, the marginal producer of methanol for the United States will still be an existing plant operating on natural gas, and natural gas costs to these producers will continue to be comparable to Btu equivalence with fuel oil at the burner tip. Based on projects already under construction, global methanol capacity will be more than adequate to meet forecast demand in 1990, and the anticipated surplus in potential supply is expected to maintain U.S. methanol prices at the cash cost of production of the marginal supplier in the United States. On this basis, the U.S. methanol price will be $270 per metric ton in 1990. At this price, exports from Canada to the U.S. Gulf Coast will continue to barely cover cash costs, but exports to the U.S. West Coast or mid-continent will be attractive. Methanol exports from the Middle East to the U.S. will be barely attractive.
The projected cost of production for methanol from a new coal-based methanol plant is $100 per metric ton higher than anticipated methanol prices in the mid-continental United States in 1990. On the other hand, these methanol prices are expected to continue to encourage adequate additional natural gas-based methanol capacity in low cost regions to meet demand throughout the forecast period.

As a result, existing natural gas-based producers in the United States will remain the marginal source of supply in 1995. The cash cost of production of the marginal producer will determine the U.S. Gulf Coast methanol price at $365 per metric ton in 1995. Canadian methanol will remain barely competitive in the Gulf Coast but viable in the U.S. Northwest or mid-continent. Netbacks on exports from the Middle East to the U.S. in dedicated tankers will be $225 per metric ton.

Western Europe

Western Europe will be the largest methanol-importing region in the world throughout the forecast period. It accounted for 45 percent of global trade in 1982 and will continue to represent over 40 percent of global trade through 1995. Brokers have become very significant in Western Europe, and over one-half of the merchant methanol market in Western Europe is already supplied by brokers and traders.

A large number of methanol producers are targeting methanol exports to Western Europe: Libya, Japanese trading companies and Celanese from Saudi Arabia, SABIC, and European traders of methanol from Trinidad, Eastern Europe and elsewhere. Imports have already driven methanol prices down to $190 per metric ton. This is below estimated cash costs of production for major Western European producers operating on a North Sea gas with natural gas priced at alternative market value.
By 1985, imports primarily from the Middle East will maintain downward pressure on methanol prices. After accounting for counter trade flow from the USSR, Western Europe will not be able to absorb anticipated production from the Middle East. Methanol from the Middle East will therefore need to find markets in the U.S. and the Pacific. At forecast 1985 landed price of $220 per metric ton, netbacks on exports from the Middle East to Western Europe will be $40 per metric ton higher than on exports to the United States and will be a preferable market. Competition for this market will maintain prices below the estimated cash costs of production for natural gas-based producers using North Sea gas.

In 1990, methanol supplies from the Middle East will remain in excess of export market opportunities in Western Europe, despite the assumption of major rationalization of West European capacity and reduction of production to 1.5 million metric tons, one-third of forecast demand.

The higher netbacks on exports from the Middle East to Western Europe will maintain pressure on methanol price. At the forecast West European methanol price of $280 per metric ton in 1990, netbacks on Middle East exports to Western Europe will still be $33 higher than on exports to the United States. Growing supplies from East Germany and the USSR are also expected to put pressure on methanol prices by 1990.

This trend is forecast to continue to 1995, when the methanol price in Western Europe will reach $375 per metric ton. At this price, methanol netbacks to the Middle East will be $40 per metric ton higher than on exports to the United States. Western European methanol producers will need below-market natural gas prices to cover cash costs at these forecast prices.

**Japan**

Japan is already dependent upon imports for 70 percent of its methanol supply. By diversifying its source of supply, it has gained the needed protection against supply disruption or unwarranted price escalation. Its joint venture in Saudi Arabia entitles it to 500 thousand metric tons, about one-half of total current demand. Japan buys methanol from each of the three Canadian methanol producers and will be taking product from New Zealand, Malaysia, and Indonesia.
Japan is in the favorable position that netbacks to the two current major methanol exporters, Canada and Saudi Arabia, will be higher on sales to Japan than to either Western Europe or the U.S. Gulf Coast. With time, new supply sources in the Pacific are expected to begin to force Canadian methanol out of Japan. Methanol price in Japan will be set primarily by alternative netbacks achievable by Canadian methanol. At forecast prices Japan remains a better market than the U.S. Gulf Coast for Canadian methanol. Nevertheless, netbacks to Canada on sales to Japan, which are favorable in 1985, will not be sufficient to attract additional capacity during the forecast period. However, netbacks from the Middle East on sales to Japan remain attractive throughout.

U.S. Gulf Coast methanol economics for the years 1983, 1985, 1990 and 1995 are shown in Table IX. Methanol shipping costs and netbacks in the major producing and market regions for 1985, 1990, and 1995 are summarized in Table X.

### TABLE IX

<table>
<thead>
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<th></th>
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</thead>
<tbody>
<tr>
<td><strong>Gas Price, $/MMBTU</strong></td>
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<td>400</td>
<td>525</td>
<td>716</td>
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<tr>
<td>Raw Materials</td>
<td>111-129</td>
<td>144-167</td>
<td>189-220</td>
<td>257-299</td>
</tr>
<tr>
<td>Utilities</td>
<td>4-6</td>
<td>7</td>
<td>12</td>
<td>20</td>
</tr>
<tr>
<td>Operating Cost</td>
<td>13-17</td>
<td>15-19</td>
<td>22-29</td>
<td>32-42</td>
</tr>
<tr>
<td>Overheads</td>
<td>13-17</td>
<td>15-19</td>
<td>22-29</td>
<td>32-42</td>
</tr>
<tr>
<td>Cash Cost</td>
<td>141-159</td>
<td>131-212</td>
<td>245-290</td>
<td>341-403</td>
</tr>
</tbody>
</table>
### TABLE X

**SHIPPING COSTS AND TARIFFS**

($/MT)

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<thead>
<tr>
<th></th>
<th>Canada</th>
<th></th>
<th>Middle East</th>
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<th></th>
<th></th>
</tr>
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<tbody>
<tr>
<td><strong>To</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>U.S. Gulf</td>
<td>103</td>
<td>138</td>
<td>194</td>
<td>76</td>
<td>102</td>
<td>140</td>
</tr>
<tr>
<td>W. Europe</td>
<td>83</td>
<td>113</td>
<td>161</td>
<td>57</td>
<td>79</td>
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<td>Japan</td>
<td></td>
<td></td>
<td></td>
<td>35</td>
<td>50</td>
<td>70</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>U.S. Gulf</th>
<th>W. Europe</th>
<th>Japan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Backs - $/MT</td>
<td>94</td>
<td>132</td>
<td>171</td>
</tr>
<tr>
<td></td>
<td>137</td>
<td>167</td>
<td>204</td>
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</tbody>
</table>
Further Development of the Methanol-Fueled Escort

Roberta J. Nichols
Ford Motor Company
USA

Abstract

The results obtained from the 40-vehicle fleet of methanol-fueled Escorts in service since 1981 are reviewed. These results provided the basis for an upgraded vehicle built on the production line. A total of 597 vehicles were built, including five advanced technology vehicles with more stringent emissions goals at equivalent thermal efficiency. Vehicle configuration, fuel and oil specifications, and emission, fuel economy and performance data are discussed. One of the major challenges when developing the vehicle was the selection of fuel system materials compatible with methanol. A follow-on program to find cost reduction solutions is underway.

1. Background

In 1980, the State of California Energy Commission (CEC) established a three-fleet program to test the suitability of alcohols as fuel for transportation vehicles (1). Fleet Three consists of 40 methanol-fueled Escorts developed by Ford for the Los Angeles (LA) County Mechanical Department, operators of Fleet Three under contract to CEC. The LA County fleet also has fifteen gasoline-fueled Escorts serving as reference vehicles. Fuel economy comparisons between the experimental methanol vehicles and the production gasoline reference vehicles are not directly comparable, however, since the Fleet Three methanol vehicles are meeting the more stringent 0.4 gm/mi NOx exhaust emission level established as a goal of the program, whereas, the gasoline vehicles are calibrated to meet the 0.7 gm/mi NOx emission standard required by California for sale of gasoline powered vehicles.

The engine/vehicle configuration of the 40-car fleet, and data obtained during development of the prototype, as well as early fleet operation, have been presented in detail previously (2, 3). These data showed that a 0.7 gm/mi NOx calibration would have improved the fuel efficiency by 16 percent compared to the 0.4 gm/mi calibration (3). Brake specific fuel consumption (BSFC) data obtained during engine dynamometer studies showed the methanol engine fuel consumption to be 10 percent lower at peak power, on an energy equivalent basis, compared to the gasoline engine. This correlated well with the measured fuel efficiency of the vehicles during the first several months of operation, with the methanol vehicles showing about a 9 percent advantage, on the average, compared to the gasoline reference fleet. This advantage began to disappear, however, as fuel system problems developed, in spite of the fact that extensive fuel system testing simulating field service had been conducted in the laboratory (4). Therefore, some modifications were made to the vehicles during the program.

2. Los Angeles County Fleet Status

2.1 In-field vehicle modifications

Shortly after delivery of the first three vehicles, the spark plug was changed one more heat range colder based on some further experience gained with high speed knock and pre-ignition. These plugs have proven quite satisfactory and in fact, in one case over 42,000 miles of service were recorded before the plugs were arbitrarily replaced.

Another field change involved replacement of the production throttle shafts due to corrosion. This problem did not appear during the extensive laboratory testing and, therefore, it was concluded
that it was related to exhaust gas recirculation (EGR) and exposure to combustion products, particularly since the problem was more severe in the secondary throttle. The corrosion would cause the throttle to stick open, making hot restart difficult. Replacement stainless steel shafts resolved the problem.

Many of the materials used in the fuel system were based on the Ford experience in Brazil with production ethanol vehicles(5). Therefore, tin plate, instead of terne plate, was used initially as the inside coating for protection of the fuel tank. After six months of service, however, the LA fleet was retrofitted with stainless steel (409) tanks because the tin plate began to blister and flake, causing filter blockage. In time, the tanks would have rusted. It is believed this may have been a manufacturing problem because the problem was not observed in the laboratory(5); a different method for applying the tin might solve the problem.

The problem which caused the most degradation to the fuel economy and posed a serious threat to the longevity of the engine first appeared in July of 1982. The production carburetor floats, made of nitrophyl (a dense, closed-cell foam), began to absorb the methanol. In some cases the measured gain in weight was as much as 50 percent. The heavy floats would "sink", causing excessive fuel flow which eventually made its way to the crankcase where it accumulated. Oil analyses showed a sharp rise in the level of wear metals when this occurred. Routine replacement of the float every two months prevented engine damage while a new float was developed.

One additional engine change was required due to a change in fuel methanol specification. In November of 1982, the fleet was switched to 10 percent unleaded gasoline (by volume) instead of 5.5 percent isopentane as the front-end volatility component added to the methanol for cold starting. This was done in the interest of cost saving and broader availability. Since the energy content of the fuel on a volume basis was increased, this change meant the vehicles were operating at an equivalence ratio more fuel-rich than previously and fuel efficiency suffered. The carbon monoxide emissions were out of calibration as well. The carburetor changes required to restore both efficiency and emissions goals were completed in April of 1983.

2.2 Summary of vehicle performance data

Throughout Phase I of the LA fleet operation (June 1981 through March 1983) a record was kept of fuel economy and driver evaluations of vehicle performance. Several of the vehicles were periodically tested for exhaust emissions. Engine component measurements and oil analyses provided additional data. A Phase I Final Report prepared by LA County Mechanical Department documents the 21 months of operation. The overall results are considered to be good, with unscheduled maintenance less than what was expected at the outset of the program.

One of the early positive feedbacks from the fleet operation was the stated preference by the drivers for the higher performance (power) level of the methanol vehicles compared to the gasoline control fleet (the increase in power was about 17 percent). The only negative comments about the methanol vehicles which lasted throughout the program pertained to cold start characteristics and a rough idle for three to five minutes during warm-up. Two vehicles have been retrofitted recently with a new intake manifold and electric heater which reportedly improved cold driveaway.

A total of sixteen emission tests were performed with several of the methanol vehicles by the California Air Resources Board (CARB) and Ford Pico Rivera (Calif.) Emissions Laboratory at odometer readings ranging from "zero" to 40,000 km, using the Federal Test Procedure. The results were quite consistent, and the vehicles continued to meet the goals of the program (0.41 HC, 7.0 CO, 0.4 NOx).

Two of the vehicles did not meet these goals when first tested. In both cases replacement of a component was required. In one case, a choke cap had to be replaced (non-methanol related); in the other case, the catalyst failed due to overheating from high levels of unburned fuel. This failure led to discovery of the float problem. It was noted that the oil of this vehicle had excessive fuel content. Even after an oil change, the engine had excessive blowby. Therefore, it was disassembled and inspected. The cam bearings and upper piston rings required replacement. (The ring gap was 1.75 mm in the worse case.) The bore wear was still satisfactory, however.

The worse case upper cylinder bore wear measurements at 16,000 and 40,000 km have been extrapolated out to a maximum allowable wear of 0.25 mm. This predicts a
useful engine life of 140,000 km. The development of the oil additive package more suitable for methanol use should extend this useful life projection (see Section 3.2).

By June of 1983, the LA County methanol fleet had accumulated 1,230,000 km of operation, with the three highest use vehicles at 87,100, 61,300 and 56,000 km. The early advantage in fuel efficiency compared to the gasoline fleet is beginning to appear again now that the fuel system problems discussed earlier have been resolved. In spite of these problems, the 40-vehicle average fuel economy for the two year period equals that of the gasoline fleet on an energy equivalent basis (approximately 9.0 1/100 km), while maintaining a more stringent NOx emission calibration.

3. 600-Car Production Build

In November of 1982, Ford was awarded a contract by the State of California to build a fleet of about 500 methanol-fueled Escorts, with a range requirement of 230 miles (368 km). It was agreed also that the vehicles would be calibrated to meet 1983 California emission standards. A total of 582 vehicles were built on the production line in June of 1983, with 501 delivered to California.

3.1 Vehicle configuration

The experience gained with the 40-car fleet was invaluable in designing and developing the production vehicles. The major features of the 1983 methanol-fueled Escort are shown in Fig. 1.

The compression ratio of the engine is 11.8:1 nominally, compared to 11.4:1 for the 40-car fleet. Other engine changes include a new distributor curve, for improved fuel economy and driveability, a chrome-faced top compression ring to resist wear, a cylinder head gasket designed for high combustion pressures and better heat distribution (derived from 1984 turbocharged engine), and an Early Fuel Evaporation (EFE) heater between the carburetor and the intake manifold. This PTC (positive temperature control) heater is similar to the one used in the 1983 gasoline Escort, but the grid design and conductor material are different (see Figure 2). The change in grid design was necessitated by the change in conductor material. The standard (gasoline version) conductor material is aluminum which eventually corrodes away when exposed to alcohol.

Fig. 2 Heater Grid: Square/Gasoline; Round/Alcohol

Development test results to determine the effect of heater design on intake air flow are given in Table I.
Table 1
Effect of Heater Design on Air Flow

<table>
<thead>
<tr>
<th>Configuration</th>
<th>Intake Manifold Pressure Drop</th>
<th>Flow Rate (m/min)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2.49 kPa</td>
<td>4.50 kPa</td>
</tr>
<tr>
<td>Spacer-no heater</td>
<td>1.96</td>
<td>2.75</td>
</tr>
<tr>
<td>Rectangular grid heater</td>
<td>1.92</td>
<td>2.69</td>
</tr>
<tr>
<td>Round grid heater</td>
<td>1.91</td>
<td>2.68</td>
</tr>
</tbody>
</table>

These results are the average of the flow measured for engine intake port 1 and 2. It was felt that the small penalty in volumetric efficiency imposed by the heater was more than off-set by the improvement in cold driveaway. Properly vaporized fuel also reduces the potential for high wear rates in the engine.

Even though the basic engine was the 1.6-liter High Output (HO) model, neither the HO carburetor nor the HO camshaft were used. Use of the standard engine camshaft and carburetor provided good fuel economy, with peak power output about the same as the 40-car fleet (see Section 3.3). The carburetor had many internal changes, of course, to account for the difference in energy content of the fuel, as well as some of the other properties such as rapid fuel cooling effects on driveability. For example, if too much fuel is applied too quickly on a "tip-in" after a light deceleration, a hesitation in response will occur. To avoid this, the same amount of fuel was applied over a longer period of time by the carburetor accelerator pump. This did induce a small penalty in cold driveability, but since this is only a small percentage of the vehicle operation time, it was accepted.

The 1983 methanol Escorts were built in both the 4-door sedan and station wagon model, with and without air-conditioning, and with automatic transmission. The fuel tank capacity is 51.1 liters.

A detailed list of the fuel system materials for the gasoline Escort, the LA County 40-car methanol fleet and the 1983 methanol-fueled Escort is given in the Appendix.

3.2 Fuel and oil specification

Development of an optimal fuel specification which addresses all the issues of methanol operation has just begun (6). One of the major concerns presently is avoidance of contaminants such as chloride ion, or use of additives with insufficient testing. At least two instances of acute fuel system problems have occurred in LA County since introduction of methanol with 10 percent gasoline. Use of gasoline in-

duced the requirement to use tank cars with vapor recovery equipment. The fuel suppliers began using tank cars made of aluminum because core of these tank cars have vapor recovery. An additive which was supposed to prevent problems from the methanol-aluminum reaction resulted in the formation of a "solid" precipitate which plugged up the filters in the fuel tanks of the vehicles. In another instance, the gasoline added to the methanol was leaded, which of course affects exhaust emission catalyst efficiency.

The 1983 methanol-fueled Escorts have been calibrated for use with 10 percent winter-grade unleaded gasoline as the cold start additive. The prototype vehicles were able to start down to -18°C (0°F) in 6-10 seconds in the cold-room tests conducted during vehicle development.

An engine oil additive package developed for use with methanol shows favorable wear rates (7). It was used throughout the development testing of the 1983 methanol Escorts, including the 300-hour engine durability test and the 50,000-mile (80,000 km) vehicle durability test. This oil additive is specified for use with the 1983 methanol units built on the production line. Some indication of undesirable deposit build-up was observed at high load operation, however, making this an open issue for continuous re-evaluation as more experience is acquired. One concern is that these deposits might aggravate the tendency for methanol to pre-ignite.

3.3 Emissions, fuel economy, and performance

Since there are no emission regulations for new methanol-fueled vehicles presently, it was agreed with CEC and CARB that meeting the 1983 California standards for gasoline vehicles (0.41 NMHC, 7.0 CO, 0.7 NOx) would be the program goal. There was also a range requirement of 230 miles (368 km) based on the EPA metro/highway driving cycle, and therefore, the minimum acceptable fuel economy was fixed also since the size of the fuel tank was fixed.

Four vehicles were hand built and used for the development work necessary to meet the program goals and vehicle requirements. The calibration of these prototype vehicles resulted in the emission and fuel economy data given in Table II. The data are the average of three tests each from three of the veh
cles using the cold-start Federal Test Procedure (FTP). The fourth vehicle was not available for emission testing because it was being utilized for general vehicle durability testing. The vehicles were 4-door sedans, with automatic transmission and air conditioning. (The station wagon model is tested at the same inertia weight.) The hydrocarbon emissions were measured with the FID which does not fully account for the oxygenated species. This is accepted procedure until new techniques are developed, however.

Table II.
Prototype Emission and Fuel Economy Results (9 Tests, 3 Vehicles) (CVS Cold Start, FTP)

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>BC</td>
<td>0.34 gm/mi</td>
</tr>
<tr>
<td></td>
<td>CO</td>
<td>3.51 gm/mi</td>
</tr>
<tr>
<td></td>
<td>NO(_x)</td>
<td>0.56 gm/mi</td>
</tr>
<tr>
<td>City FE*</td>
<td>8.45 1/100 km</td>
<td></td>
</tr>
<tr>
<td>Highway FE*</td>
<td>5.67 1/100 km</td>
<td></td>
</tr>
<tr>
<td>H/H FE*</td>
<td>7.20 1/100 km</td>
<td></td>
</tr>
<tr>
<td>Vehicle Range (M/H)</td>
<td>384 km (240 miles)</td>
<td></td>
</tr>
</tbody>
</table>

*Note: The FE is given in gasoline energy equivalent: 1.85 volume fuel methanol equals one volume gasoline.

The first ten (10) vehicles built on the production line went through drive evaluation. The idle mode is considered the weak spot and in fact, the engine idles better without the idle stabilizer (developed for the gasoline configuration and manifold vacuum). Five of these ten vehicles were emission tested in order to validate the prototype calibration. The results are given in Table III.

Table III.
Average Emissions and Fuel Economy: Five Production-line Vehicles (CVS Cold-Start, FTP)

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>BC</td>
<td>0.34 gm/mi</td>
</tr>
<tr>
<td></td>
<td>CO</td>
<td>1.76 gm/mi</td>
</tr>
<tr>
<td></td>
<td>NO(_x)</td>
<td>0.61 gm/mi</td>
</tr>
<tr>
<td>City FE*</td>
<td>8.67 1/100 km</td>
<td></td>
</tr>
<tr>
<td>Highway FE*</td>
<td>5.99 1/100 km</td>
<td></td>
</tr>
<tr>
<td>H/H FE*</td>
<td>7.46 1/100 km</td>
<td></td>
</tr>
<tr>
<td>Vehicle Range (M/H)</td>
<td>370 km (231 miles)</td>
<td></td>
</tr>
</tbody>
</table>

*Note: Gasoline energy equivalent (see Table II).

As can be seen, these five vehicles are meeting the goals of the program in spite of the fact that they were "green" vehicles with less than 80 km of operation. The fuel efficiency is expected to improve after the vehicles go through "break-in" and friction is reduced.

Figure 3 shows the torque and power for the 1983 methanol-fueled Escort compared to the 1983 HO gasoline-fueled Escort. The power for the base engine gasoline-fueled Escort is shown also since the methanol Escort is really a hybrid of the HO and base engine. As discussed earlier, the base camshaft and carburetor were utilized, trading power for fuel economy.

4. Five Advanced Technology Vehicles

The contract with the State of California includes the agreement to build five vehicles which meet 0.4 gm/mi NO\(_x\) with the same fuel efficiency as the vehicles calibrated to meet 0.7 gm/mi NO\(_x\). This work is in progress. The Escort with electronic fuel injection (EFI) was selected as the base vehicle. This engine utilizes the EEC-IV for engine spark and fuel control (electronic engine control). The previous development work for alcohol strategy and calibration conducted for Ford of Brazil with the EEC-IV has been very helpful even though Brazil does not have any emission regulations presently. These vehicles are still undergoing development. The best results to date are given in Table IV.
### Table IV.

**Preliminary Emission and FE Results**

1983 EFI Methanol Escort

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>HC</td>
<td>0.40 gm/mi</td>
</tr>
<tr>
<td>CO</td>
<td>2.24 gm/mi</td>
</tr>
<tr>
<td>NOx</td>
<td>0.47 gm/mi</td>
</tr>
<tr>
<td>City FE*</td>
<td>7.51 1/100 km</td>
</tr>
<tr>
<td>Highway FE*</td>
<td>5.23 1/100 km</td>
</tr>
<tr>
<td>M/H FE*</td>
<td>6.50 1/100 km</td>
</tr>
</tbody>
</table>

*Note: Gasoline energy equivalent (see Table II).*

These preliminary results show a fuel efficiency improvement, but the 0.40 gm/mi goal for NOx emissions has not been achieved. Also, this work has been done with a manual-transmission vehicle. It is planned to transfer this calibration to a vehicle with an automatic transmission, which will result in a decrease in fuel efficiency, but this should also decrease the NOx emissions.

### 5. Future Fuel System Materials

Evaluation of suitable plastics for the methanol vehicle fuel system in the future is underway. An alternative fuel tank material for methanol appears to be polyethylene. This material is compatible with alcohol and at the same time permits production of a larger volume tank for placement in essentially the same vehicle location and space because plastic can be molded into shapes not feasible with drawn steel.

A prototype fuel pump with a plastic housing is under test. In addition, a program has been initiated to study the feasibility of a plastic carburetor. While the use of stainless steel and nickel plating are solutions at present, the proper plastic material could offer even better durability, along with a cost reduction.

### 6. Summary

The results obtained to date with the LA County 40-car methanol fleet and the 587 1983 methanol-fueled Escorts built on the production line indicate that fuel methanol can be used successfully in transportation vehicles, providing the proper materials, fuel and lubricants are developed. The results show an opportunity for improvement in fuel efficiency and performance, while continuing

### Acknowledgements

The author wishes to acknowledge the dedicated work of the people in the Alternative Fuels Section, Powertrain Research Laboratory, without whom there would be no results to report. Also, throughout the methanol program the support received from the Fuels and Lubricants Department has been invaluable. In particular, the author thanks Granger Chui and Earle Cox for providing the material list in the Appendix.

### References

### Appendix

#### Material List for Methanol-Fueled Vehicles

<table>
<thead>
<tr>
<th>Component</th>
<th>Production 1.6 L Escort (Gasoline)</th>
<th>Los Angeles 1981 Escort Fleet (Methanol)</th>
<th>California 1981 Escort Fleet (Methanol)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Tank</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>. Tank Body</td>
<td>Terne coated steel</td>
<td>Tini plated steel, 409 SS (8/82)</td>
<td>444 Stainless Steel</td>
</tr>
<tr>
<td>. Vent Tube</td>
<td>Terne coated steel</td>
<td>Tin plated steel</td>
<td>Ni-Plated 304 S.S.</td>
</tr>
<tr>
<td>. Filler Tube</td>
<td>Terne coated steel</td>
<td>Tin plated steel</td>
<td>Ni-Plated 304 S.S.</td>
</tr>
<tr>
<td>. Solder (vent, filler tube to body)</td>
<td>60% Pb. 40% Sn.</td>
<td>93% Sn. 5% Sb</td>
<td>93% Sn. 5% Sb</td>
</tr>
<tr>
<td>. Locking Ring</td>
<td>Terne coated steel</td>
<td>Tin plated steel</td>
<td>Terne coated steel ('83 prod.)</td>
</tr>
<tr>
<td>. Support Strap</td>
<td>Terne coated steel (1983)</td>
<td>No change</td>
<td>Terne coated steel ('83 prod.)</td>
</tr>
<tr>
<td>. Tube &amp; Flange Assembly</td>
<td>Terne coated steel</td>
<td>Ni plated steel</td>
<td>Ni plated steel</td>
</tr>
<tr>
<td>. Float Arm</td>
<td>Terne coated steel</td>
<td>Ni plated steel</td>
<td>Ni plated steel</td>
</tr>
<tr>
<td>. Float</td>
<td>Terne coated steel</td>
<td>Ni plated brass</td>
<td>Ni plated brass</td>
</tr>
<tr>
<td>. Check Valve</td>
<td>None (1981)</td>
<td>No change</td>
<td>No change</td>
</tr>
<tr>
<td>. Case</td>
<td>None</td>
<td>No change</td>
<td>No change</td>
</tr>
<tr>
<td>. Element</td>
<td>Viton (1983)</td>
<td>No change</td>
<td>No change</td>
</tr>
<tr>
<td>. Fuel Filter</td>
<td>Terne coated steel</td>
<td>Stainless Steel</td>
<td>Stainless Steel</td>
</tr>
<tr>
<td>. Armor</td>
<td>Steel Zn plated &amp; dichromated</td>
<td>No change</td>
<td>No change</td>
</tr>
<tr>
<td>. Element</td>
<td>Steel Zn plated &amp; dichromated</td>
<td>No change</td>
<td>No change</td>
</tr>
<tr>
<td>. Carburetor</td>
<td>Nylon</td>
<td>No change</td>
<td>No change</td>
</tr>
<tr>
<td>. Body</td>
<td></td>
<td>Stainless steel</td>
<td>Stainless steel</td>
</tr>
<tr>
<td>. Power Valve Disc</td>
<td>Zinc Alloy</td>
<td>SAE 903 + Ni-plate with lead balls &amp; some brass restrictors in place</td>
<td>SAE 903 + SAE 925 + Ni-plate; lead balls &amp; some brass restrictors in place</td>
</tr>
<tr>
<td>. Power Valve Washer</td>
<td>925 (1933)</td>
<td>SAE 903</td>
<td>SAE 903</td>
</tr>
<tr>
<td>. Air Horn</td>
<td>Steel-dichromated</td>
<td>Steel</td>
<td>SAE 903, Ni plated</td>
</tr>
<tr>
<td>. Fuel Inlet Needle Spring</td>
<td>Steel-dichromated</td>
<td>SAE 903, Ni-plated</td>
<td>SAE 903, Ni plated</td>
</tr>
<tr>
<td>. Fuel Inlet Needle Tip</td>
<td>Zinc alloy, SAE 903</td>
<td>Phosphor bronze, Ni plated</td>
<td>Phosphor bronze, Ni plated</td>
</tr>
<tr>
<td>. Fuel Inlet Needle Clip</td>
<td>Phosphor bronze</td>
<td>Vernay Viton (new compound)</td>
<td>Vernay Viton (new compound)</td>
</tr>
<tr>
<td>. Vapor Valve Spring</td>
<td>Music wire, tin plated (1981)</td>
<td>Steel</td>
<td>Stainless steel</td>
</tr>
<tr>
<td>. Booster Venturi</td>
<td>Zinc alloy, SAE 903</td>
<td>Music wire, Ni plated</td>
<td>Not used</td>
</tr>
<tr>
<td>. Accelerator Pump Washers</td>
<td>Zinc alloy, SAE 903</td>
<td></td>
<td></td>
</tr>
<tr>
<td>. Accelerator Pump Pin</td>
<td>Steel</td>
<td></td>
<td></td>
</tr>
<tr>
<td>. Accelerator Pump Return Spring</td>
<td>Steel</td>
<td>SAE 903, Ni plated</td>
<td>SAE 903, Ni plated</td>
</tr>
<tr>
<td>. Flange Assy.</td>
<td>Steel</td>
<td>Steel, Ni plated</td>
<td>Steel, Ni plated</td>
</tr>
<tr>
<td>. Primary Throttle Shaft</td>
<td>Nitrophenyl/stainless steel</td>
<td>Steel</td>
<td>Stainless Steel</td>
</tr>
<tr>
<td>. Secondary Throttle Shaft</td>
<td>Steel</td>
<td>No change, stainless steel (8/82)</td>
<td>Stainless steel</td>
</tr>
<tr>
<td>. Throttle Shaft Screws</td>
<td>Steel</td>
<td>No change</td>
<td>Steel</td>
</tr>
<tr>
<td>. Float hinge pin</td>
<td>Brass</td>
<td>No change</td>
<td>Brass</td>
</tr>
<tr>
<td>. Idle adjustment needle</td>
<td>Steel</td>
<td>No change</td>
<td>Stainless steel</td>
</tr>
</tbody>
</table>

334
FURTHER DEVELOPMENT OF THE METHANOL - FUELED ESCORT
LOS ANGELES COUNTY 40 - CAR FLEET

- Over one million miles of service
- Highest mileage vehicle at 70,000 miles
- In-field changes
  - spark plug
  - throttle shafts
  - fuel tank
  - carburetor float
  - fuel composition / required jet changes
40 - CAR FLEET PERFORMANCE DATA

- Driveability
  - driver preference for higher power
  - rough idle / 3 - 5 minute warm-up

- Durability
  - minimal unscheduled maintenance
  - useful engine life: 140,000 km for worse case bore wear

- Emissions
  - 16 tests show vehicles continue to meet program goals
    (0.41 NMHC, 7.0 CO, 0.4 NOx)

- Fuel efficiency
  - Reference gasoline vehicles calibrated at 0.7 Nox
  - Advantage for methanol about 10%
Major Features

- Engine: 1.6L HO with base camshaft / carb, - 1984 head gasket
- Pistons: Compression ratio nominally 11.8 : 1
- Spark plugs: 2 ranges colder
- Distributor: recurved at part - load and WOT
- Fuel tank / fuel lines / straps
- Fuel pump: nickel plated
- Fuel sending unit: nickel plated
- Carburetor: nickel plated
- Carburetor spacer / heater: new design
- Engine oil: unique additive package
## EFFECT OF HEATER ON AIR FLOW

<table>
<thead>
<tr>
<th>Configuration</th>
<th>Intake Manifold Pressure Drop</th>
<th>Flow Rate (m³/min)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2.49 KPa</td>
<td>4.98 KPa</td>
</tr>
<tr>
<td>Spacer - no heater</td>
<td>1.92</td>
<td>2.69</td>
</tr>
<tr>
<td>Rectangular grid heater</td>
<td>1.91</td>
<td>2.68</td>
</tr>
<tr>
<td>Round grid heater</td>
<td>1.92</td>
<td>2.69</td>
</tr>
</tbody>
</table>
# PROTOTYPE EMISSIONS AND FUEL ECONOMY RESULTS

(9 tests, 3 vehicles)

CVS Cold Start, FTP

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>0.34 gm / mi</td>
</tr>
<tr>
<td>HC</td>
<td></td>
<td>3.51 gm / mi</td>
</tr>
<tr>
<td>CO</td>
<td></td>
<td>0.56 gm / mi</td>
</tr>
<tr>
<td>NO\textsubscript{x}</td>
<td></td>
<td>8.45 l / 100 km</td>
</tr>
<tr>
<td>City FE</td>
<td></td>
<td>5.67 l / 100 km</td>
</tr>
<tr>
<td>Highway FE</td>
<td></td>
<td>7.20 l / 100 km</td>
</tr>
<tr>
<td>M / H FE</td>
<td></td>
<td>384 km (240 miles)</td>
</tr>
<tr>
<td>Vehicle Range (M / H)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Note:** FE is gasoline energy equivalent
## Average Emissions and Fuel Economy:

**Five Production Line Vehicles**

CVS Cold Start, FTP

<table>
<thead>
<tr>
<th>Emission</th>
<th>Value (gm/mi)</th>
<th>Emission</th>
<th>Value (gm/mi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HC</td>
<td>0.34</td>
<td>CO</td>
<td>1.76</td>
</tr>
<tr>
<td>NOₓ</td>
<td>0.61</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fuel Economy</th>
<th>Value (l/100 km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>City FE</td>
<td>8.67</td>
</tr>
<tr>
<td>Highway FE</td>
<td>5.99</td>
</tr>
<tr>
<td>M / H FE</td>
<td>7.46</td>
</tr>
</tbody>
</table>

**Vehicle Range (M / H)**

370 km (231 miles)

Note: FE is gasoline energy equivalent
TABLE II

Fuel Methanol Specification
(Reference 4)

<table>
<thead>
<tr>
<th>Component</th>
<th>Specification</th>
<th>Use/Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unleaded Gasoline*</td>
<td>9-11%</td>
<td>a) Odorant</td>
</tr>
<tr>
<td></td>
<td></td>
<td>b) Coldstart aid</td>
</tr>
<tr>
<td></td>
<td></td>
<td>c) Flame Luminosity</td>
</tr>
<tr>
<td></td>
<td></td>
<td>d) Change vapor phase</td>
</tr>
<tr>
<td></td>
<td></td>
<td>flammability</td>
</tr>
<tr>
<td>Water</td>
<td>&lt;0.5%</td>
<td>Anhydrous methanol is</td>
</tr>
<tr>
<td></td>
<td></td>
<td>an impossibility</td>
</tr>
<tr>
<td>Total Chlorine</td>
<td>&lt;0.001%</td>
<td>Severe engine wear</td>
</tr>
<tr>
<td>(organic + inorganic)</td>
<td></td>
<td>linked to residual chlorinated solvents</td>
</tr>
<tr>
<td>Acidity</td>
<td>&lt;0.003%</td>
<td></td>
</tr>
<tr>
<td>Pb</td>
<td>&lt;0.003 gm/l</td>
<td></td>
</tr>
<tr>
<td>S</td>
<td>&lt;0.01%</td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>&lt;0.001 gm/l</td>
<td></td>
</tr>
<tr>
<td>Filterability</td>
<td>&lt;0.1 gm/liter</td>
<td></td>
</tr>
<tr>
<td>Distillation Residue</td>
<td>&lt;0.5%</td>
<td></td>
</tr>
<tr>
<td>Methanol</td>
<td>Balance (88% minimum)</td>
<td></td>
</tr>
</tbody>
</table>

Final fuel to have 6-9 Reid vapor pressure.

* Winter grade gasoline (11-13 RVP) suggested
## PRELIMINARY EMISSION AND FE RESULTS

1983 EFI Methanol Escort

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>HC</td>
<td>0.40 gm / mi</td>
<td></td>
</tr>
<tr>
<td>CO</td>
<td>2.24 gm / mi</td>
<td></td>
</tr>
<tr>
<td>NOₓ</td>
<td>0.47 gm / mi</td>
<td></td>
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<tr>
<td>City FE</td>
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<td></td>
</tr>
<tr>
<td>Highway FE</td>
<td>5.23 l / 100 km</td>
<td></td>
</tr>
<tr>
<td>M / H FE</td>
<td>6.50 l / 100 km</td>
<td></td>
</tr>
</tbody>
</table>

Note: FE is gasoline energy equivalent
ON-GOING METHANOL RESEARCH

- DISSOCIATED METHANOL \( (\text{CH}_3\text{OH} \xrightarrow{\text{catalyst}} \text{CO} + 2\text{H}_2) \)
  - OPERATE ON CO + H\(_2\) AT PART LOAD FOR GOOD THERMAL EFFICIENCY
  - INSTALLED ON 1.6L EFI ENGINE

- VARIABLE MIXTURE STUDIES
  - SENSOR TELLS EEC-IV (ELECTRONIC ENGINE CONTROL) WHAT MIXTURE OF METHANOL AND GASOLINE IS IN TANK (CAN VARY FROM 0 TO 100% METHANOL)

- ALL PLASTIC FUEL SYSTEM
  - POLYETHYLENE TANK
  - FUEL PUMP WITH PLASTIC HOUSING
  - PLASTIC CARBURETOR

- CONTINUE OIL/FUEL ADDITIVE STUDIES
GASOLINE FROM NATURAL GAS

by

Gerald F. Tice

and

Hal C. Spohn

Fluor Engineers, Inc.
Advanced Technology Division
Irvine, California

Thailand - U.S. Natural Gas Utilization Symposium
Bangkok, Thailand
February 7-11, 1984

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I. INTRODUCTION

SLIDE 1: SCOPE OF PAPER

Synfuels from competitively-priced natural gas are today a viable alternate to crude-derived products. This paper examines the major factors that will influence such projects. Particular emphasis is given to the prospects for gas-based synfuels to supply domestic product markets in Thailand. Some market and resource assessment data are given for other Pacific Basin countries.

Although the assigned topic of the paper concerns gasoline production, available technology offers the option of maximizing either gasoline or distillate product. Because this flexibility is potentially important, the paper includes both product options. In the discussion, references to transport fuels should be understood to include both gasoline and distillate fuels.

SLIDE 2: PROCESS OPTIONS

Liquid transport fuels can be produced from natural gas by three major routes:

- Methanol-to-Gasoline (MTG)
- Fischer-Tropsch
- Methanol (for fuel use)

The MTG process was developed by Mobil Corporation. The first commercial operation will start up in New Zealand in 1985. Gasoline production capability of that plant will be 14,000 BPD.

Operation of the Arge and Synthol Fischer-Tropsch processes began by Sasol in South Africa in 1955; two major capacity additions using the Synthol technology were completed in the early 1980s under Fluor project management. All of that capacity is based on syngas produced by coal gasification. The Synthol Process is owned by Sasol and the Arge Process is owned by Ruhrchemie, Lurgi, and Sasol. A number of developers have current programs aimed at new catalysts or reactor designs for the future.

Although methanol is the subject of another paper, it is included here to illustrate its relationship to the "standard" fuel options. Modern methanol processes are available from several licensors.
II. MARKETS

SLIDE 3: THAILAND CRUDE OIL AND NATURAL GAS BALANCE

The demand and supply of crude oil and natural gas in Thailand is shown in Slide 3, as forecasted by the World Bank. The forecast indicates a slow and controlled growth in oil use with a major increase in the use of domestic gas and a smaller increase in domestic oil production as envisioned by current exploration prospects. The forecast assumes increased use of hydroelectric power and lignite-based power production. Crude oil supply is primarily by imports; this suggests that an opportunity exists for import displacement.

SLIDE 4: POTENTIAL IMPACT OF SYNFUELS

The distribution of Thai oil products consumption is shown here for the purpose of comparing the petroleum product substitution capabilities of the synthetic fuel options.

Methanol (MeOH) has two distinct market uses for auto fuel. One is as a low volume blend (less than 5%) in gasoline with cosolvents and additives. The other use is as medium or high volume blends in gasoline where it can substitute for up to about 85 percent of the gasoline. Methanol used in high volume blends with gasoline is often called "neat" methanol. Low volume blends can be marketed interchangeably with gasoline as is being done today in the U.S. However, medium and high volume blends require fuel system and/or engine modifications. Since these blends cannot be used in automobiles that have not been designed or modified to accept them, they would become a new grade of fuel. This factor introduces a complexity in storage, distribution, and marketing that is not present in any of the other options.

The amount of methanol which can be used domestically in Thailand in low volume blends is quite small, at about 5 percent of the gasoline market. Neat methanol could replace a large volume of the domestic gasoline demand. A potential for methanol which is not shown may eventually exist in diesel fuel applications, which are currently under test.

Gasoline from the MTG Process has the potential to satisfy all domestic gasoline requirements, since this product is fully interchangeable with crude oil-derived gasoline. The current commercial configuration of the MTG Process does not provide distillate product capability.

Fischer-Tropsch processes yield products with the highest potential to substitute for petroleum products in the Thai market. They offer the potential to produce both gasoline and distillates which are interchangeable with oil-derived products. Synthetic light fuel oil could also be substituted for residual fuel oil if an overall benefit to the country resulted.

Current refinery nameplate capacity in Thailand is 176,000 BPSD and product imports amount to about 50,000 BPD.
Also shown on the slide to establish perspective is the nominal 15,000 BPD output of a single natural gas-to-synfuels plant. A single unit of this type would be small in comparison with either the total Thai market or existing refinery capacity. As a result, the installation of such a facility should not disrupt existing operations. A logical initial objective would be displacement of product imports.

III. NATURAL GAS RESOURCES

SLIDE 5: POTENTIAL FOR TRANSPORT FUELS FROM NATURAL GAS IN SELECTED PACIFIC BASIN COUNTRIES

The potential for producing transport fuels from natural gas in selected Pacific Basin countries is indicated in Slide 5. The potentials are shown in terms of the number of 15,000 BPD plants which could be built based upon uncommitted gas or on replacement of imported oil. Uncommitted gas quantities are based upon proven reserves less thirty years of current domestic and LNG-dedicated usage.

It is clear that the potential for domestic utilization of synthetic fuels to replace oil imports is quite large in Australia, Thailand, and New Zealand. The estimated currently uncommitted gas reserves are large enough to support large-scale domestic synfuels programs in each country shown, but Malaysia and Indonesia have a current surplus of oil for export. The long-term potential that may emerge with those exporters as oil production declines was not analyzed. Thailand, Australia, and New Zealand appear to have the best balance between gas availability and oil import substitution potentials.

It is not expected that these maximum synfuels potentials will be realized. Other uses are planned and will be selected for some of this uncommitted gas. On the other hand, a single 15,000 BPD synfuels plant requires only 150 MM SCFD of gas feed, giving a reserve requirement of 1.5 trillion cubic feet for thirty years of operation. Since this requirement is small relative to potential reserves in each of the countries shown, there is a good possibility for future synfuels projects to be developed in parallel with other gas-based projects.

The effect on world transport fuel markets of building a large number of these synthetic fuel plants would be small, as shown in the insert table on Slide 5.

SLIDE 6: SPECIFIC THAILAND NATURAL GAS AVAILABILITY

This is a more detailed review of the Thai potential for synthetic fuels from natural gas than that shown on Slide 5.
The first bar shows the reserves available as described in the Petroleum Authority of Thailand (PTT) brochure on The Gas Plant Project. Reserves are separated into proven, probable, and possible. Other sources contain higher estimates of reserves. The World Bank estimates a high total potential of 35 trillion cubic feet as compared to the PTT total of 24 trillion cubic feet. Some sources estimate a proven reserve of 13 trillion cubic feet. In spite of recent deratings of some natural gas reserves, the potential for increasing proven and probable reserves appears high considering the current high level of exploration.

The second bar represents thirty years of reserves assumed committed for domestic uses at 1983 levels, which amounts to 1.9 trillion cubic feet or about 30 percent of the proven reserves shown. A single 15,000 BPD synfuels project would require commitment of 1.5 trillion cubic feet for thirty years of operation, as shown in the third bar. This quantity would fit easily into the remaining uncommitted but proven reserves.

IV. TECHNOLOGY

SLIDE 7: BLOCK FLOW DIAGRAM

In each of the process options, the first step is the conversion of natural gas into syngas, a mixture of hydrogen and carbon oxides. This can be done by tubular steam reforming, autothermal reforming, or partial oxidation. The commonly used steam reformer reacts steam and hydrocarbon over a fixed bed of nickel catalyst within the radiant tubes of a furnace. Typical outlet operating conditions are 800-900°C and atmospheric to 35 atm pressure.

Fischer-Tropsch synthesis is the direct conversion of syngas into hydrocarbons. Typical reaction product liquid is a mixture of paraffins, olefins, aromatics, and oxygenates (alcohols, ketones, acids). Upgrading processes are used downstream to increase the yield and quality of transport fuels. Relative yields of distillate to gasoline can be highly influenced by the selection of the upgrading processes as well as the Fischer-Tropsch synthesis process. Downstream processing can include some combination of alkylation, oligomerization, cracking, catalytic reforming, and hydrotreating processes.

Methanol synthesis is the other primary conversion step for transport fuels from syngas. Methanol product can be blended with gasoline and additives as a substitute fuel, or can be converted to gasoline in the MTG process. Reaction product from MTG is a mixture of paraffins, olefins, and aromatics. Alkylation is used downstream to increase the yield and quality of the gasoline product.
Operating conditions of each of the synthesis processes are moderate, as shown here. Each process uses a solid catalyst and is exothermic. Temperature control in current commercial processes is achieved using specialized reactor designs, including:

- Entrained-bed
- Fixed-bed with gas quench
- Tubular fixed-bed with steam generation outside the tubes

The fixed-bed MTG Process is carried out step-wise. The first stage converts a portion of the methanol to dimethyl ether (DME) and water. Effluent from the first stage is converted to gasoline in a second stage.

The present commercial Fischer-Tropsch processes are the entrained-bed Synthol Process and the fixed-bed Arge Process, each using iron-based catalysts. Development programs now under way offer the potential of new catalysts and reactor designs for the future. One example of this work is the development of multifunctional catalysts combining zeolites with metals. Shape selectivity and water-gas shift activity can be achieved in addition to Fischer-Tropsch activity in this way. Alternate reactor systems are also being piloted or demonstrated, as shown on the next slide.

Methanol synthesis is the only option shown in which the per-pass conversion to syngas is equilibrium limited. The conditions shown represent the modern low temperature process, although some modern plants have design pressures as low as 50 atm.

While this is only a sampling of the numerous efforts being carried out worldwide in synthetic transport fuels technology, it does identify several major publicly-announced programs.

The fluid-bed version of MTG is expected to offer an improved service factor and thermal efficiency over the fixed-bed design. This program is sponsored by Mobil, URBK, Uhde, the U.S. Department of Energy, and the West German Ministry of Research and Development.

While objectives of the Fischer-Tropsch programs vary, most programs are geared to achieve at least some of the following:

- High per-pass conversions of synthesis gas
- Minimum formation of methane and light ends
- Minimum formation of oxygenated by-products
- Flexibility to alter the distillate/gasoline mix in the product
The Mobil and Union Carbide programs shown are being carried out under contract from the U.S. Department of Energy, while the Sasol and Gulf/Badger programs are privately funded.

In the product upgrading area, the Mobil Olefins to Gasoline and Distillate (MOGD) process can be used to maximize either gasoline or distillate production from olefins produced in the synthesis step. This process, which is the subject of another paper, has been tested commercially in refinery-scale equipment. It is based on a shape-selective zeolite catalyst.

SLIDE 10: DISTILLATE/GASOLINE FLEXIBILITY

The importance of process flexibility to alter the relative production of gasoline and distillate fuels is illustrated here.

The horizontal lines show the market demand for distillate as a percent of gasoline plus distillate. Values range from about 80 percent in Thailand, Indonesia, and Malaysia to 30 percent in the U.S.

The vertical bars show the approximate practical range of product slate design flexibility in the combined synthesis and upgrading sections for MTG and Fischer-Tropsch technology. While the current version of the MTG Process produces all gasoline, current Fischer-Tropsch processes produce both gasoline and distillate, with distillate ranging from about 35 percent to 75 percent of the liquid product. Developing Fischer-Tropsch technology offers the prospect of extending that range in both directions.

Fischer-Tropsch technology is therefore better able to match the aggregate product mixes of the existing markets in Thailand and the other Pacific Basin countries shown. While a single project would not have to match the national mix, it is expected that the desired mix will vary substantially from project to project. For example, Thailand's current 50,000 BPD of product imports are nearly all distillate materials. If an initial objective were displacement of product imports with synfuels, it appears that this would require high yields of distillate from natural gas.

V. ECONOMICS

SLIDE 11: DEFINITION OF CASES

An economic case study was made of the three major process options for producing transport fuels from natural gas. In all cases, the natural gas feed rate was set at 150 MM SCFD as methane. Methanol capacity in the methanol and MTG cases is 5,000 metric tons per day.
Product capacities shown are expressed as BPD gasoline equivalent, which includes credit for by-product LPG in the MTG and Fisher-Tropsch cases. In addition, the Fisher-Tropsch cases were credited for distillate co-product at its gasoline Btu equivalent. The thermal efficiencies shown likewise include credit for gasoline and distillate fuels as well as LPG. On this basis, product BPD is directly proportional to thermal efficiency.

Methanol has the highest thermal efficiency of the three options. The lower value for MTC, which includes both the methanol and gasoline production steps, reflects losses for processing of methanol to gasoline. Fisher-Tropsch processes cover a range of thermal efficiencies on either side of the MTC Process.

In the development of these cases, current generation technology was used as a basis for the MTG and methanol options. However, for the Fischer-Tropsch option, the cases span a range from current generation technology to processes that could emerge in the next few years from development work underway in that field.

SLIDE 12: MAJOR ECONOMIC ASSUMPTIONS

The major economic assumptions which are consistent with Symposium guidelines are displayed on Slide 12. All base case runs were at 100 percent equity, but one financed case with 75 percent debt at 10 percent interest was developed for comparison. Debt repayment in the financed case is on an eight year basis with level principal payments. All rate-of-return calculations are on a constant dollar after tax basis.

Operating costs were also calculated consistent with Symposium guidelines.

SLIDE 13: THAI PETROLEUM PRODUCT PRICES

These mid-1983 plant fence and dealer (retail) prices for gasoline, diesel and fuel oil in Thailand are shown here as a point of reference for comparison to the calculated prices of the study cases.

SLIDE 14: CAPITAL COSTS

The capital costs, including working capital, for the various processes to convert natural gas to transport fuels are shown in Slide 14.

Plant facilities costs are based on factored estimates (USGC basis). These estimates are for self-sustaining grass-roots facilities, including:

- All process units, including product upgrading units to make unleaded regular gasoline in the MTG and Fisher-Tropsch cases
- Utility supply and distribution
All offsites, including product storage and shipping facilities

Contingency

Depreciable capital includes plant facilities plus the following owner's cost items:

- Initial charge of catalysts and chemicals
- Startup and organization expenses

Methanol has the lowest capital cost. The capital cost for Mobil MTG falls within the range for Fischer-Tropsch processes.

SLIDE 15: REQUIRED PRODUCT PRICES AT PLANT FENCE

The prices required at the plant fence to develop a 10 percent constant dollar after tax ROI are shown in Slide 15. The $/gallon prices were calculated with credit for all non-gasoline products at their gasoline Btu equivalent. Natural gas prices were varied from $2/MM Btu to $4/MM Btu to establish the bottom and top of the price ranges shown for each option.

Methanol is the cheapest alternate based on calculated prices at the plant fence. It has an advantage of $0.29/gallon over MTG with $2/MM Btu feed gas and $0.35/gallon with $4/MM Btu feed gas. This price advantage would be reduced in distribution, storage, and marketing of the new grade of fuel that would result from use of methanol in medium and high volume blends. As stated earlier, a small volume of methanol could be used for low volume blends without creating the need for a new product infrastructure.

The calculated prices at the plant fence for the MTG and Fischer-Tropsch options are higher than for methanol, but the products in these cases are fully interchangeable with crude-derived products. Since the Fischer-Tropsch band represents the projected results from developing processes as well as from commercial processes, it covers a wider price range than the other options. Although current Fischer-Tropsch technology yields a somewhat higher gasoline price than that calculated for the MTG Process, the potential for cost reduction appears to be good. The greater product flexibility of the Fischer-Tropsch processes was described in the Technology section of this paper.

Mid-1983 Thai gasoline prices at the plant fence and at the dealer are shown for reference on the slide. The methanol, MTG, and Fischer-Tropsch options all show at least some calculated prices falling within the range between plant fence and dealer prices. The upper range of the prices based on Fischer-Tropsch cases exceeds the dealer prices.

None of these results consider the potential benefits of natural gas based synfuels development to the Thai economy. Ultimate project feasibility could be highly influenced by policies on gas pricing and taxation.
SLIDE 16: MOBIL MTG COST COMPONENTS

This is a breakdown of the calculated product cost components for the MTG Process, based on achieving a target 10 percent ROI (100 percent equity). The natural gas cost at $4.00/MM Btu is $200 MM per year, or about half of the total. Capital recovery requirements are a third of the required selling price. Operating costs and taxes amount to about 20 percent of the total required price. The total revenue required to achieve this ROI goal is $394 MM per year at a sale price at the plant fence of $1.73/gallon of gasoline produced.

SLIDE 17: SENSITIVITY OF ROI AND ROE TO PRODUCT PRICE - MOBIL MTG PROCESS

This plot shows rate of return as a function of product price for the MTG Process. For the 100 percent equity cases at $2/MM Btu and $4/MM Btu gas prices, each $0.25/gallon change in gasoline price causes a 4-5 percent change in ROI.

A single debt-financed case is shown at the $4/MM Btu gas price. It assumes a 75/25 debt/equity ratio and a 10 percent debt interest rate. Each $0.25/gallon change in gasoline price in this case causes about an 8 percent change in ROE.

SLIDE 18: SENSITIVITY OF ROI TO CHANGES IN MAJOR ECONOMIC VARIABLES - MOBIL MTG PROCESS

This shows the sensitivity of rate of return to changes in major economic variables for the MTG Process on a 100 percent equity basis. A range of ±20 percent is shown on each variable so the relative importance of the variables can be compared.

A given change in product price has about twice the impact on ROI as the same percent change in gas feed price or capital cost. Changes in operating costs have the lowest ROI effect of the major variables.

VI. CONCLUSIONS

SLIDE 19: COMPARISON OF TECHNOLOGIES

This slide summarizes key aspects of the alternate technologies studied. Although each of the processes is available for license, it is worth reiterating that only the Fischer-Tropsch and methanol processes are commercially demonstrated. Since operation of the first commercial MTG unit will not begin until 1985, all information presented in this paper on that process reflects predicted, rather than actual, performance.
Methanol has the lowest calculated price at the plant fence based on today's technologies, but has the highest limitations in the marketplace. Its use in low volume blends would be limited to a maximum penetration of about 5 percent of the Thai gasoline market. High volume blends, or neat methanol, could penetrate over time up to about 85 percent of the gasoline market; however, in this application, methanol would be a new grade of fuel requiring new infrastructure for storage, distribution, and marketing. Required additives to neat methanol fuel would be an added cost component. Specially designed or modified automobiles would also be required to accept neat methanol fuel. Costs and potential delays in developing the market for neat methanol were not analyzed here, but would be important in the final evaluation of that option.

The calculated price at the plant fence for gasoline via MTG is about 25 percent above that for methanol, reflecting the cost of converting methanol to gasoline. This process will produce gasoline which is interchangeable with crude-derived product.

The Fischer-Tropsch processes include a range of options from those now commercial to those projected from development programs. Calculated prices at the plant fence span a relatively wide range above and below those for the MTG Process. These processes produce fuels that are interchangeable with crude-derived products. Since they can be designed to produce both gasoline and distillate in varying proportions, Fischer-Tropsch processes offer the greatest potential to substitute for crude-derived products in the marketplace. The high level of development activity on these processes should have a positive future impact on this option.

**SLIDE 20: OVERALL CONCLUSIONS**

This slide shows the overall conclusions concerning the potential for synfuels from natural gas in Thailand.

The impact of a current and projected high dependence on imported oil for transport fuels provides an incentive to search for substitute fuels. Although the degree of import displacement could ultimately be very large, this can be carried out stepwise to avoid disruption of existing operations. A stepwise approach would also minimize any strain on domestic manpower and financial resources.

Proven but uncommitted domestic natural gas resources as of today would support at least three 15,000 BPD synfuels projects, which would approximately displace current product imports. When probable and possible reserves are also considered, the synfuels potential exceeds the total Thai oil import requirement, including crude oil imports.

Three technology options are available for these synfuels projects. The calculated synthetic gasoline prices at the plant fence for each of these are higher than comparable prices for gasoline from crude oil but generally lower than dealer prices. Product price is the economic variable having greatest impact on project ROI.
Further evaluation, including a full cost/benefit analysis of project impact on the Thai economy, is needed to establish the viability of synfuels from natural gas. Benefits at the national level will increase the competitive strength of such projects.

SLIDE 21: BENEFITS OF SYNFUELS DEVELOPMENT TO THAI ECONOMY

Important factors for consideration in a full cost/benefit analysis of synfuels development are shown on this concluding slide.

The primary financial impact of such projects on the Thai economy would be due to retention of product revenues within the nation. Earnings from natural gas would flow to the producers and the Central Government. Tax revenues would be generated as royalties on gas production and as corporate income taxes.

The cost of oil imported to Thailand in 1983 was in the region of $2 billion. Since synthetic fuels from domestic natural gas would be a substitute for imported oil, the balance of payments would improve with synfuels development. In addition, Thailand's energy independence would increase. Economic dislocations such as those caused by soaring international oil prices in 1973 and 1979 would be lessened.

Employment opportunities would increase in conjunction with engineering and construction as well as operation of new facilities from the wellhead through the synfuels plant.

While there are many alternates for natural gas utilization that would produce some of these benefits, synfuels production can do so with very low market risk. It does not depend on either growth of domestic product markets or on export markets to assure required revenue flows to a worldscale operation. The market exists today.
BIBLIOGRAPHY


SLIDE 1

SCOPE OF PAPER

• MARKETS
• NATURAL GAS RESOURCES
• TECHNOLOGY
• ECONOMICS
• CONCLUSIONS

† FLUOR
# PROCESS OPTIONS FOR TRANSPORT FUELS FROM NATURAL GAS

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*FLUOR*
### SLIDE 3

**THAILAND CRUDE OIL AND NATURAL GAS BALANCE**

*1981-1995 (MILLION BOE)*

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* World Bank Data
POTENTIAL IMPACT OF SYNFUELS IN
THAI PETROLEUM PRODUCT MARKET

- Current Refinery Capacity, BPSD
  - Fuel Oil: 200
  - Diesel: 70
  - Kerosene & Jet Fuel: 30
  - Gasoline: 30

- Synfuels Plant:
  - Gasoline: 1.5
  - Low Vol. Methanol Blends in Gaso: 25.5
  - Mobil MTG Gasoline: 30
  - Fischer-Tropsch Gaso & Distillates: 130

Including Substitution of Light Fuel Oil for Heavy

Potential Max. Market Capture
SLIDE 5

POTENTIAL FOR SYNTHETIC FUEL FROM NATURAL GAS IN SELECTED PACIFIC BASIN COUNTRIES

NO. OF 15,000 BPD PROJECTS

ONE PLANT
13 PLANTS (EQUIVALENT TO THAI OIL IMPORTS)
40 PLANTS (POTENTIAL FROM UNCOMMITTED GAS IN ALL 5 COUNTRIES)

WORLD TRANSPORT FUEL DEMAND

% OF 1985

0.06
0.8
2.5

NUMBER OF PROJECTS POSSIBLE W/UNCOMMITTED GAS RESERVES

NUMBER OF PROJECTS TO DISPLACE OIL IMPORTS

MALAYSIA
AUSTRALIA
THAILAND
INDONESIA
NEW ZEALAND
SPECIFIC THAILAND FEED AVAILABILITY FOR NATURAL GAS TO TRANSPORT FUELS @ 30 YEARS RESERVE LIFE

TRILLION CUBIC FEET OF NATURAL GAS

- PROVEN: 6
- PROBABLE: 9
- POSSIBLE: 10
- RESERVES*: 24

30 YR RESERVE AT ESTIMATED 1983 PRODUCTION RATE: 1.9
30 YR RESERVE FOR ONE 15,000 BPD GAS TO TRANSPORT FUEL PLANT: 1.5

* PTT DATA

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SLIDE 7

BLOCK FLOW DIAGRAM OF PROCESS OPTIONS
TRANSPORT FUELS FROM NATURAL GAS

- Natural Gas
  - Reformer
    - Fischer-Tropsch Synthesis → Product Recovery & Upgrading → Gasoline & Distillates
    - MTG → Product Recovery & Upgrading → Gasoline
    - Methanol Synthesis → Gasoline & Diesel Substitute

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* Two-Step Process
EXAMPLES OF
NEW TECHNOLOGY PROGRAMS

MTG

- 100 B/D FLUID-BED PILOT OPERATION IN WEST GERMANY

FISCHER-TROPSCH

- SASOL FIXED FLUIDIZED-BED AND SLURRY PILOT PROGRAMS; MID - 1983 STARTUP FOR FIXED FLUID-BED DEMONSTRATION PLANT

- MOBIL SLURRY PILOT PROGRAM

- GULF/BADGER FIXED AND FLUID-BED PILOT PROGRAMS; 37 B/D DEMONSTRATION PLANT UNDER CONSTRUCTION

- UNION CARBIDE CATALYST DEVELOPMENT PROGRAM

UPGRADING

- MOBIL SHAPE-SELECTIVE OLEFIN OLIGOMERIZATION (MOGD) PROCESS

♀ FLUOR
DISTILLATE/GASOLINE PRODUCTION FLEXIBILITY

DISTILLATE/GASOLINE COMPARISON WITH MARKET DEMAND

MTG

FISCHER-TROPSCH

ALL GASOLINE

MARKET DEMAND

UNITED STATES

AUSTRALIA, NEW ZEALAND

THAILAND

INDONESIA, MALAYSIA

MTG

FISCHER-TROPSCH

ALL GASOLINE

MARKET DEMAND

UNITED STATES

AUSTRALIA, NEW ZEALAND

THAILAND

INDONESIA, MALAYSIA

MTG

FISCHER-TROPSCH

ALL GASOLINE

MARKET DEMAND

UNITED STATES

AUSTRALIA, NEW ZEALAND

THAILAND

INDONESIA, MALAYSIA
## DEFINITION OF CASES

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* Based on gasoline HHV = 5.2 x 10^6 Btu/B

** Covers combined methanol and methanol-to-gasoline processes
SLIDE 12

MAJOR ECONOMIC ASSUMPTIONS*

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<td>USGC Dollars</td>
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<tr>
<td>Price &amp; Cost Units</td>
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<tr>
<td>Natural Gas Price</td>
<td>$4.00/MM BTU</td>
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<tr>
<td>Operating Factor</td>
<td>330 Days/Year</td>
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<tr>
<td>Income Tax Rate</td>
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<tr>
<td>Depreciation Type</td>
<td>10-Yr St. Line</td>
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<tr>
<td>Capital Contingency</td>
<td>20%</td>
</tr>
<tr>
<td>Startup &amp; Organiz. Expense</td>
<td>2% of Investment</td>
</tr>
<tr>
<td>Debt Interest Rate for ROE</td>
<td>10%</td>
</tr>
</tbody>
</table>

*Assumptions (Except ROI Goal) Set By Symposium Guidelines

© FLUOR
THAI PETROLEUM PRODUCT PRICES  
(MID-1983)

<table>
<thead>
<tr>
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<th>PLANT FENCE</th>
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<th>DEALER</th>
<th></th>
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<tr>
<td></td>
<td>BAHT/LITER</td>
<td>U.S. $/GAL*</td>
<td>BAHT/LITER</td>
<td>U.S. $/GAL*</td>
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<tr>
<td>PREMIUM GASOLINE</td>
<td>5.49</td>
<td>0.89</td>
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<tr>
<td>REGULAR GASOLINE</td>
<td>4.98</td>
<td>0.81</td>
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<td>DIESEL</td>
<td>4.96</td>
<td>0.81</td>
<td>6.70</td>
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<tr>
<td>LT. FUEL OIL</td>
<td>4.07</td>
<td>0.66</td>
<td>4.32</td>
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*At 1 BAHT = U.S. $0.043
### CAPITAL COSTS

<table>
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<tr>
<th></th>
<th>MOBIL MTG</th>
<th>FISCHER-TROPSCH</th>
<th>METHANOL</th>
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</thead>
<tbody>
<tr>
<td>PLANT FACILITIES COST</td>
<td>580</td>
<td>540 TO 800</td>
<td>470</td>
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<td>$MM (1983 USGC)</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>TOTAL DEPRECIABLE CAPITAL*</td>
<td>600</td>
<td>560 TO 860</td>
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<tr>
<td>WORKING CAPITAL</td>
<td>165</td>
<td>160 TO 215</td>
<td>150</td>
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</table>

* Includes initial catalyst/chemicals, startup and organization expenses

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REQUIRED PRODUCT PRICES @ PLANT FENCE

SLIDE 15

MID-1993
THAI PRICES, $/GAL

PLANT FENCE

DEALER

0.81
REGULAR GASO

0.89
PREMIUM GASO

1.76
REGULAR GASO

1.90
PREMIUM GASO

0.89
REGULAR GASO

MED. & HIGH VOL. BLENDS

0.97
1.33

1.26
1.73

1.07
2.40

FISCHER-TROPSCH

MOBIL MTG

METHANOL

NOTE: ALL PROCESSES EVALUATED AT BOTH $2.00 AND $4.00/MM BTU
FEED GAS PRICES AT A 10% TARGET ROI (CONSTANT DOLLAR, AFTER TAX).

$/GALLON GASOLINE EQUIVALENT

0.50 1.00 1.50 2.00 2.50

$/MM BTU

4.00 6.00 8.00 10.00 12.00 14.00 16.00 18.00 20.00

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MOBIL MTG
COST COMPONENTS

<table>
<thead>
<tr>
<th>Component</th>
<th>$ MM/yr</th>
<th>$/GAL GASO PRODUCED</th>
<th>$/MM BTU</th>
<th>% Total</th>
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</thead>
<tbody>
<tr>
<td>Natural Gas (@ $4.00/MM BTU)</td>
<td>200</td>
<td>0.88</td>
<td>7.09</td>
<td>51</td>
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<tr>
<td>Operating Costs</td>
<td>60</td>
<td>0.26</td>
<td>2.09</td>
<td>15</td>
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<tr>
<td>Capital Recovery</td>
<td>125</td>
<td>0.55</td>
<td>4.45</td>
<td>32</td>
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<tr>
<td>Income Tax @ 35% (W/10 YR. ST. LINE DEPR.)</td>
<td>26</td>
<td>0.11</td>
<td>0.84</td>
<td>6</td>
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<tr>
<td>By-Product Credits (Propane &amp; Butane)</td>
<td>(17)</td>
<td>(0.07)</td>
<td>(0.56)</td>
<td>(4)</td>
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<tr>
<td>Revenue Req'd @ 10% Const. DOLLAR AFTER TAX ROI</td>
<td>394</td>
<td>1.73</td>
<td>13.91</td>
<td>100</td>
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SLIDE 17
SENSITIVITY OF ROI & ROE TO PRODUCT PRICE
MOBIL MTG PROCESS

ROE @ $4.00/MM BTU GAS
ROI @ $2.00/MM BTU GAS
ROI @ $4.90/MM BTU GAS

ROI @ $2.00/MM BTU GAS
ROI @ $4.00/MM BTU GAS

ROI GOAL = 10%

% ROI OR ROE, CONSTANT $ AFTER TAX

$/GAL GASOLINE EQUIVALENT

$/MM BTU

ROE ASSUMPTIONS
25% EQUITY
10% INTEREST ON DEBT

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SLIDE 18

SENSITIVITY OF ROI TO CHANGE IN
MAJOR ECONOMIC VARIABLES
MOBIL MTG PROCESS

BASE CASE VALUES OF VARIABLES
PRODUCT PRICE $1.73/GAL
GAS PRICE $4/MM BTU
FACILITIES COST $580 MM
VARIABLE/FIXED COSTS $60 MM/YR

PRODUCT PRICE
NATURAL GAS PRICE
FACILITIES COST
VARIABLE & FIXED OPERATING COSTS W/O GAS FEED
SLIDE 19

COMPARISON OF TECHNOLOGIES

Methanol
- Lowest Cost at Plant Fence Today
- Non-Standard Fuel Requires New Infrastructure
- Lowest Substitution Potential in Marketplace

Methanol-To-Gasoline (MTG)
- Higher Cost Than Methanol at Plant Fence
- Standard Gasoline Fuel

Fischer-Tropsch
- Costs Span Range Above and Below MTG
- Standard Gasoline and Distillate Fuels
- Highest Product Flexibility
- High Substitution Potential in Marketplace
- Highest Level of Development Activity
OVERALL CONCLUSIONS

- Incentive For Oil Import Displacement
- Natural Gas Reserves Adequate To Support Synfuels Production
- Proven Technology Available To Convert Natural Gas To Transport Fuels
- Calculated Synthetic Gasoline Prices Higher Than Plant Fence Prices for Gasoline From Crude Oil But Generally Lower Than Dealer Prices
- Full Analysis of Benefits To Thai Economy Will Increase Competitive Strength of Synfuels
BENEFITS OF SYNFUELS DEVELOPMENT TO THAI ECONOMY

- Stimulates Revenues From Domestic Resource
- Creates Tax Revenues
- Positive Effect on Balance of Payments
- Increases Energy Independence
- Stimulates Employment

† FLUOR
THE PRODUCTION, ECONOMICS
AND USES OF SYNTHESIS GAS

BY

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Stone & Webster Engineering Corporation
Boston, Massachusetts
USA

Thailand - United States
Natural Gas Utilization Symposium
Bangkok, Thailand
Introduction

The OPEC oil crisis in 1973 was not the first time in history that the industrialized world experienced an energy shortage. An historical review will show that short-term energy shortages were commonplace. In fact, in the early 19th century, the United States literally ran out of wood, the principal source of energy at that time. In 1865, the noted social scientist, W. Stanley Jevans, predicted that English industry would grind to a halt due to the exhaustion of England's coal supply. The invention of new mining techniques and improved transportation systems soon solved England's problem and the conversion from wood to coal in the United States created the necessary energy supply to support industrial growth.

Recent analysis of historical evidence strongly suggest that primary energy sources and technological innovations go hand and hand. In 1980, Cesare Marchetti (1), proposed an interesting hypothesis (Figure 1) which suggests that as existing forms of energy saturate the market, new forms are developed and substitution from one energy source to another occurs. This substitution process does not seem to be entirely dependent upon the availability of the energy source. Statistical data plotted in Figure 1 clearly shows a decrease in coal utilization in favor of oil despite the relative availability of each resource.

This format for energy substitution, in particular the market saturation point for crude oil, is further supported by a comparison of the oil price index and fractional energy substitution over the last eighty years (Figure 2). Historically, the cost of energy has flared at least twice in the past and at precisely those points in time where specific sources of energy reached their saturation point. The current maxima in energy price shown in Figure 2 appears to predict the saturation point for oil in the energy market place. If the hypothesis is correct, this maxima suggests a future price reduction in oil and the gradual substitution to natural gas with perhaps long-term emphasis on nuclear power.
The transition from oil to natural gas would be impossible in a stagnant technological environment. Increased utilization of natural gas is not only dependent upon its availability and the ease with which one can extract and transport it, but also with the availability of certain innovations that will further its acceptance into existing energy use systems.

Referring again to history, and noting the pioneering work by Gerhard Mensch (2), statistical data relating to the frequency of innovations can be correlated with surprising accuracy with the Kondratieff long wave cycles of economic activity (Figure 3). Mensch shows that during each of the 55 year Kondratieff cycles, economic depression coincides with periods of high innovation activity. Innovation as defined by Mensch is the collection of a number of inventions which occur over a period of time, into the development of a new industry. These industries or innovations appear in bunches and apparently contribute to the upswing in economic activity completing the economic cycle.

Economic or long-wave cycles and innovation cycles appear to identify with energy substitution cycles. The last two innovation peaks have appeared at the saturation points for coal and wood as principal sources of energy. As a result, it is tempting to suggest a "connection" between economic trends, innovation frequency and energy substitution that occur in predictable cycles.

Extrapolation of Mensch's data predicts that the decade of maximum innovation should begin now and will peak in 1989. If Marchetti's conclusions regarding energy substitution are correct, the swing from oil to natural gas is also at hand. With this in mind, it may be possible to identify those innovations that will support the transition from oil to natural gas. To do this, all one has to do is identify those technological trends that point in the direction of natural gas as an energy source that will fit into today's energy use system.

The emergence of what many forecasters refer to as single carbon chemistry will certainly promote natural gas as a feedstock for not only traditional chemicals such as ammonia and methanol, but for such chemical intermediates as
acetic acid, ethylene glycol, as well as the basic building blocks of the chemical industry; olefins and aromatics (Figure 4). More importantly, the use of synthesis gas for the production of transportation fuels will be required before a complete transition from crude oil to natural gas can be made. The production of gasoline and diesel fuel from natural gas will represent that collection of inventions which could sponsor the formation of a new industry and increase the energy market share for natural gas. If there is but a single invention that would qualify in the development of this innovation, it is the discovery of manufacturing techniques and new uses for zeolite catalysts.

It can be said with relative confidence that zeolite catalysts are the key that will unlock the liquid transportation fuel market to natural gas (Figure 5). The development of zeolite catalysts has been actively underway for the last twenty years, with nearly 30% of all patents on zeolites issued in 1982 alone.

**Technology**

Mobil Oil Company is one of the principal patent holders for development work related to zeolite catalysts and are responsible with the New Zealand Government for the first commercial introduction of zeolite catalysts for the utilization of natural gas in the production of liquid transportation fuel.

The new Mobil technology that will be discussed in this paper is an offshoot of the same technology that is being commercialized in New Zealand and is based upon the conversion of methanol or light olefin feedstock to gasoline and distillate. The Mobil Olefin to Gasoline and Distillate Process (MOGD) provides an opportunity to expand current natural gas product markets into the diesel fuel area.

Synthesis gas is the key in producing light olefins via Fischer-Tropsch chemistry or methanol, which in turn provide suitable feedstocks for diesel fuel production using the Mobil technology. Synthesis gas is usually produced from the methane portion of the natural gas/liquids mix. Ethane, propane, LPG and natural gasoline are relatively high value chemical feedstocks which are traditionally recovered from the heavier than methane fraction of the natural gas/liquid mix (Figure 6).
Discounting the possibility of cracking LPG or natural gas liquids to olefins, there are three basic process concepts that can be utilized to produce liquid transportation fuels from natural gas. The first concept (Figure 7) involves synthesis gas conversion to methanol as an intermediate with the subsequent conversion of methanol at high selectivity to diesel fuel and/or gasoline. This concept is relatively effective with a potential product mix of 80% diesel and 20% olefinic gasoline.

Prior to the introduction of the Mobil MTG process in New Zealand, the principal source of hydrocarbons from syngas has been through Fischer-Tropsch chemistry. Fischer-Tropsch processes have been operated commercially at both high and low temperatures producing a product spectrum of light olefinic to heavier paraffinic hydrocarbon products.

The fixed bed low temperature Fischer-Tropsch process was commercially developed by Lurgi and Sasol at Sasolburg, South Africa over thirty years ago. This technology was incorporated by Sasol as a means to produce heavier distillate range material and hard waxes. To utilize low temperature Fischer-Tropsch for maximum diesel production would require a relatively sophisticated refinery as shown in Figure 3, with the incorporation of heavy wax hydrocracking, a technology that has yet to be tested on a commercial scale.

With the introduction of the MOGD process, the options for Fischer-Tropsch chemistry for producing diesel fuel have been expanded. The high temperature or Synthol Fischer-Tropsch process in combination with MOGD may provide an alternative to diesel fuel production from methanol. Since the Synthol process produces a principally olefinic hydrocarbon product, it is possible to upgrade the C₃ to 330°F material via MOGD and maximize diesel fuel (Figure 9). This integration of MOGD and Synthol processes has the advantage of greatly simplifying the downstream refinery necessary to recover gasoline and distillate products.

**Economics**

To test the economics of producing diesel and gasoline from natural gas, a block flow diagram, material balance, and order of magnitude capital costs were developed for the system shown in Figure 10.
For 100 MM SCFD of natural gas and condensate with the composition shown in Figure 10, it is feasible to produce 16,000 barrels per day of combined diesel and gasoline. This product mix consists of approximately 10,000 BPD high quality diesel blend stock, 2,500 BPD natural gasoline recovered as condensate from the natural gas and 3,500 BPD high octane byproduct gasoline.

The processing concept shown in Figure 10 has been placed in gross utility balance with net operating costs reflected as natural gas consumed. The overall process thermal efficiency is estimated at approximately 65%.

Incorporating a discounted cash flow rate of return of 10%, 100% equity financing, 35% tax, ten year straight line depreciation and an operating life of 15 years, product values were calculated at varying costs for natural gas (Figure 11). A capital cost basis for U.S. Gulf coast, mid-1983 dollars and the above economic criteria indicate that high quality diesel blend stock and gasoline can be produced at a cost of $49/barrel with natural gas selling for 4 dollars per million Btu.

A profitability analysis using the same economic basis shows that at rates of return of less than 10%, the product values for distillate and gasoline from natural gas approach those of producing the same products from crude oil (Figure 12). The economics of producing conventional liquid transportation fuels from natural gas can be improved substantially at lower feedstock costs and with profit tax incentives.

One of the difficulties of developing the preceding economic analysis lies in identifying the real value of MOGD diesel product. This problem is better understood by comparing the physical properties of MOGD distillate with the U.S. Industry Standard for diesel fuel. It can be seen from Figure 13 that MOGD distillate, with its high cetane, low pour point and high API gravity would make an excellent blending stock to upgrade lower quality distillates such as crude derived cat cracker cycle oils. This in itself would justify a higher than diesel fuel value for MOGD product and further improve the economics developed in this paper.
Bibliography

(1) Marchetti, C., Society as a Learning System: Discovery, Invention and Innovation Cycles Revisited, Technological Forecasting and Social Change, 18, 267-282 (1980)

(2) Mensch, C., Stalemate In Technology Ballinger Pub., Cambridge, MA. 1979
APPROXIMATE WORLD FRACTIONAL ENERGY SUBSTITUTION

BASED UPON STATISTICAL DATA PROJECTIONS


FIGURE 1
OIL COST INDEX VS FRACTIONAL ENERGY SUBSTITUTION

SOURCES:
1. BEIJDORFF & LUKAS, ENERGY PRICE: PERVERSIVE CARRIER OF INFORMATION, SIPM
INNOVATION FREQUENCY/ECONOMIC ACTIVITY

SOURCE: G. MENSCH, STALEMATE IN TECHNOLOGY, BALLINGER PUB. CO., 1979

FIGURE 3
SYNTHESIS GAS UTILIZATION OPTIONS

- AMMONIA
- HYDROGEN
- METHANOL
- ACETIC ACID
- VINYL ACETATE
- ACETIC ANHYDRIDE
- ETHYLENE GLYCOL
- ETHANOL
- OXO ALCOHOLS
- OLEFINS
- AROMATICS
- GASOLINE
- DIESEL/JET

TRADITIONAL OPTIONS

NEW OPTIONS
ZEOLITE CATALYSTS – OPTIONS FOR SYNGAS TO TRANSPORTATION FUELS

SYNGAS

FISCHER-TROPSCH

ZEOLITES

GASOLINE

DIESEL

METHANOL

ZEOLITES

GASOLINE

DIESEL

OLEFINs

ZEOLITES

AROMATICS

ETHYLENE

PROPYLENE

BUTYLENE

FIGURE 5
SYNGAS PRODUCTION ONLY

NATURAL GAS/LIQUIDS → C₄/C₅ SEPARATION → SULFUR REMOVAL → REFORMER → SYNTHESIS GAS

→ C₅⁺ GASOLINE

SYNGAS, LPG, ETHYLENE FEEDSTOCK, METHANE PRODUCTION

NATURAL GAS/LIQUIDS → CO₂ REMOVAL → FRACTIONATION UNIT

→ METHANE TO PIPELINE
→ ETHANE/PROPANE TO ETHYLENE PLANT
→ LPG
→ NATURAL GASOLINE
→ REFORMER → SYNTHESIS GAS

FIGURE 6
SYNGAS TO DIESEL FUEL VIA METHANOL

Reformer Furnace Fuel

Hydrogen

PSA

Methanol Synthesis

Synthesis Gas

LPG

Mobil Proprietary Processes

OLEFINIC GASOLINE 20%

Hydrotreater

DIESEL BLENDING STOCK 80%

FIGURE 7
SYNGAS TO DIESEL FUEL VIA LOW TEMPERATURE FISCHER-Tropsch SYNTHESIS GAS TAIL GAS PRIMARY FRACTIONATION CAT POLY OR MOGD GASOLINE DISTILLATE DEWAX DIESEL WAX HYDRO-CRACKING HEAVY FUEL OIL ALCOHOLS FIGURE 8
SYNGAS TO DIESEL FUEL
VIA HIGH TEMPERATURE FISCHER-TROPSCH

TO HYDROGEN RECOVERY

LIGHT HYDROCARBONS
TO ETHYLENE PLANT

C₃-C₄ OLEFINs

LPG

METHANE
TO REFORMER

SYNTHESIS GAS

METHANE TO REFORMER

CO₂ REMOVAL

TAIL GAS

TAIL GAS

HIGH TEMP. FISCHER-TROPSCH

LIGHT OIL

HEAVY OIL

LIGHT OIL

ALCOHOLS

Mobil MOGD

-330F

OLEFINIC GASOLINE

MOBIL MOGD

-330F

HYDRO-
TREATER

DIESEL FUEL

HYDROGEN FROM RECOVERY

RESID

FIGURE 9
NATURAL GAS TO DIESEL VIA METHANOL

NAT. GAS COMPOSITION

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<tr>
<th>COMPONENT</th>
<th>MOL %</th>
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<td>CH₄</td>
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<td>C₂⁺</td>
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ESTIMATED PRODUCT RATE

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<th>RATE</th>
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<tr>
<td>DIESEL</td>
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<tr>
<td>GASOLINE</td>
<td>6,000</td>
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FEED RATE 100 MM SCFD

FIGURE 10
PRODUCT COST
NATURAL GAS TO DIESEL

BASIS
100% EQUITY
10% DCF
35% TAX
10 YR DEPRECIATION
15 YR OPERATION

FIGURE 11
PROFITABILITY
NATURAL GAS TO DIESEL VIA METHANOL

FIGURE 12
# Distillate Product Quality

<table>
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<tr>
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<th>Typical MOGD Hydrotreated Distillate</th>
<th>US Industry Standard</th>
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<tbody>
<tr>
<td>Gravity, °API</td>
<td>50</td>
<td>30–37</td>
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<tr>
<td>Bromine No.</td>
<td>4</td>
<td>-</td>
</tr>
<tr>
<td>Pour Point, °F</td>
<td>-60</td>
<td>+20</td>
</tr>
<tr>
<td>Cetane No. *</td>
<td>56</td>
<td>45</td>
</tr>
</tbody>
</table>

*Engine Tested

Source: Mobil Oil Corp.

**Figure 13**
MOBIL OLEFINS TO GASOLINE AND DISTILLATE PROCESS (MOGD)

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Presented at:
Thailand-United States
Natural Gas Utilization Symposium
Bangkok, Thailand
February 7-11, 1984
MOBIL OLEFINS TO GASOLINE AND DISTILLATE PROCESS

Mobil Oil Corporation has recently developed a process for converting light olefins, such as propylene and butylene, to gasoline and distillates. When the Mobil Olefins-to-Gasoline-and-Distillates (MOGD) process is operated in the gasoline mode, distillate production can be kept very low. In the distillate mode, operations can be adjusted to yield as much as 80 weight percent of the total product as high quality distillate fuels: diesel, jet, and No. 2 fuel oil.

Mobil first demonstrated the feasibility of the process technology on a laboratory scale, using a variety of light olefins as feedstocks. Commercial-scale refinery testing confirmed both the process technology and the product quality.

The MOGD process is yet another application of the unique family of Mobil ZSM-5 shape selective catalysts. The process and the catalyst are covered by Mobil patents or patent applications both in the United States and abroad.

Mobil Commercial Zeolite Catalyst

The conversion of light olefins takes place through the use of a zeolite catalyst discovery by Mobil scientists (Slide 3). It is a commercially manufactured catalyst - one of a family of synthetic crystalline zeolite (ZSM-5 class) catalysts. The landmark discovery came as part of Mobil’s continuing efforts to find better catalysts for improved petroleum refining.
The catalyst is characterized by a well-defined two directional pore structure, with the pores approximately 5 1/2 angstroms in diameter. The MOGD reaction takes place inside these long channels which results in the formation of a shape selective olefinic product. In general, the product structure is a long straight chain with an occasional methyl group sitting on it (Slide 3).

The high selectivity characteristics of the ZSM-5 type catalysts have made possible the development of several Mobil processes which, themselves, have proved the performance of this catalyst. Since the mid-1970's, Mobil has commercialized and licensed five different fixed bed processes. The Mobil Methanol to Gasoline (MTG) process, now being commercialized in New Zealand, will be the sixth. Throughout the world, about 30 such catalytic units are now operating commercially or under construction for processing petroleum and petrochemical feedstocks, with the largest commercial reactor processing 55,000 barrels per day of feed.

These fixed bed processes were scaled up directly to commercial size after development work in laboratory bench units similar to that used for developing the MOGD process. In all cases, the catalyst has performed satisfactorily. Also, for MOGD a 210 bbl/day test run was made using commercial scale equipment in a Mobil refinery. This test successfully demonstrated both gasoline and distillate modes and gave results analogous to our bench units.

Mobil, which has several decades of experience in catalyst manufacture, produces catalyst suitable for use in the MOGD process on a commercial scale.
The MOGD process has potential applications for converting olefins derived from petroleum refining, natural gas and synthetic fuels manufacture, with greater than 90 weight percent yield of gasoline plus distillate (Slide 4).

Examples of potential feedstock sources include the C$_3$-C$_9$ olefins derived from the Fischer-Tropsch synthesis, from methanol-to-olefin conversions, and from conventional refinery catalytic cracking operations. Saturate (non-olefin) streams, such as liquified petroleum gas (LPG) and natural gas liquids (NGL), can be converted to acceptable feedstocks using conventional steam cracking or dehydrogenation processes. MOGD is particularly attractive for synthetic fuels processes where light olefins are a major intermediate product (Slide 1). Also, for a mixed feed of olefins and non-olefins, the non-olefins need not be extracted and will pass through the MOGD process unreacted.

The value of the MOGD process lies primarily in its mode flexibility - its ability to convert light olefins from the above sources into high quality gasoline and/or distillates. While a number of competitive processes are available for conversion of C$_3$-C$_4$ olefins to gasoline, such as alkylation and catalytic polymerization, few will convert these same materials to acceptable distillate products. The MOGD process, which can upgrade C$_5^+$ as well as C$_3$-C$_4$ olefins, produces jet and diesel fuels having superior burning and fluidity qualities.
Products From MOGD

Mobil has developed typical data for MOGD products—diesel fuel, jet fuel and gasoline—based on commercial-scale refinery testing of the process. The charge stock was a C₃-C₄ olefin mixture.

The enclosed figures (Slides 6, 7, and 8) compare the properties of MOGD-produced diesel fuel with the standard commercial diesel fuel derived from crude oil by non-MOGD processes and presents a similar comparison of MOGD-derived jet fuel. The MOGD product data relative to pour point and sulfur content are worthy of note. In general, MOGD distillate fuels, after olefin bond saturation, not only meet or exceed normal commercial specification, but exhibit many properties which make them premium value blend stocks. Data is also shown on the quality of the MOGD gasoline which can be coproduced with the distillate.

MOGD Process Design

The accompanying diagram provides a simplified MOGD process flow scheme for maximum distillate production (Slide 5). As shown, a normal design uses three reactors with interstage cooling and liquid recycle for heat removal. Raw MOGD distillate is sent to a conventional hydrotreating facility as the final step in producing a high quality jet or diesel fuel. Operating conditions and materials of construction are quite similar to conventional petroleum refinery and petrochemical processing facilities throughout the world. This is true, as well, for regeneration of the catalyst. The process can be designed to alternate operation between the distillate mode and the gasoline mode, using a broad range of light olefins from refineries or synfuels plants.
SLIDE 1
NATURAL GAS TO FUELS

Natural Gas

Steam Reform

Syn Gas

CO + H₂

Fischer Tropsch

C₃ Olefins

Mobil Olefin to Gasoline and Distillate

Gasoline

Distillate

Lt. Oxygenates

Mobil Hydrotreating/Dewaxing

Distillate

Methanol Synthesis

Methanol

Mobil Methanol to Gasoline

Gasoline

Dehydrogenation

Mobil Methanol to Olefins

Mobil Olefin to Gasoline and Distillate

Gasoline

Distillate

Liquids

Dehydrogenation

Methyl

Methanol to Gasoline
MOGD

MOBIL OLEFIN TO GASOLINE AND DISTILLATE

- Upgrades C$_2$ to C$_{10}$ olefinic stocks

- Gives high G+D yield from light olefins
  Greater than 90\% G+D

- Product flexibility — wide range of G/D ratios
  From 0.12 to >100

- Produces high quality gasoline and distillate
  92 R+O Gasoline
  52 Cetane Distillate

- Proven in demonstration run
  3 Month run in Mobil Refinery
SLIDE 3

CATALYST IS ZSM-5

CATALYST CHANNEL STRUCTURE

SHAPE SELECTIVE REACTION PATH

Light Olefins $\Rightarrow$ Gasoline $\Rightarrow$ Distillate

\[
C = C - C \rightarrow C - C = C - C - C - C - C - C - C - C
\]

Propylene \hspace{1cm} Product \hspace{1cm} Structure
### MOGD Process Yields

**C<sub>3</sub>+/C<sub>4</sub>+</** FEED

<table>
<thead>
<tr>
<th></th>
<th>Max Distillate Mode</th>
<th>Gasoline Mode</th>
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<tbody>
<tr>
<td><strong>C&lt;sub&gt;1&lt;/sub&gt;-C&lt;sub&gt;3&lt;/sub&gt;</strong></td>
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<tr>
<td><strong>C&lt;sub&gt;4&lt;/sub&gt;</strong></td>
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<td>5</td>
</tr>
<tr>
<td><strong>C&lt;sub&gt;5&lt;/sub&gt;-165°C Gasoline</strong></td>
<td>18</td>
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<td><strong>165°C+ Distillate</strong></td>
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<tr>
<td><strong>C&lt;sub&gt;5&lt;/sub&gt;-200°C Gasoline</strong></td>
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<tr>
<td><strong>200°C+ Distillate</strong></td>
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</tbody>
</table>
SLIDE 5

MOGD PROCESS FLOW
Max Distillate Mode

Chg

Adiabatic Reactors

Interreactor Coolers

Recycle Pump

Make-up Air

Regeneration Circuit

LPG

Gasoline to Stabilization

Distillate to Hydrotreating
### MOGD DISTILLATE QUALITY

<table>
<thead>
<tr>
<th>MOGD Product</th>
<th>MOGD Product</th>
<th>Industry Standard</th>
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<tr>
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<tr>
<td>Specific 15°/15°</td>
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<td>.78</td>
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<td>Bromine No.</td>
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<tr>
<td>Pour Point, °C</td>
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<td>Viscosity, cs @ 40°C</td>
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<td>Cetane Number (Engine)</td>
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<tr>
<td>Sulfur, wt %</td>
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<td>&lt;.002</td>
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<td>90% B.P., °C</td>
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## MOGD JET FUEL QUALITY

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<td>Specific 15°/15°</td>
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<td>Smoke Point, mm;</td>
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<td>JFTOT, °C</td>
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<tr>
<td>Sulfur Content, wt %</td>
<td>&lt;=.002</td>
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</table>
MOGD GASOLINE QUALITY

R + O 92
M + O 79

Gravity,
Specific, 15°/15° 0.73
UNIT AND OPERATION

Modified wax hydrofinisher
210 bbl/day of FCC C_3/C_4 mix (62% olefin)
70 days on stream

OBJECTIVE

- Demonstrate all modes of operation in large scale
- Demonstrate controllability in large multireactor adiabatic unit
- Provide sufficient distillate products for fleet testing
- Demonstrate catalyst regenerability

RESULTS

Same as small pilot plant
SLIDE 10

ADVANTAGES OF MOGD

- Feedstock can be a broad range of light olefins and paraffins from refinery or syn fuels plants
- Requires no supplemental feedstocks
- Catalyst is a commercially made solid extrudate which is regenerated conventionally
- Process can be designed to operate alternately in distillate or gasoline mode
- High quality products contain no sulfur or nitrogen compounds
CURRENT EGAT POWER GENERATION UTILIZING FUEL GAS

to be presented at
Natural Gas Utilization Symposium to be held in February, 1984
at Bangkok, Thailand

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CURRENT EGAT POWER GENERATION UTILIZING FUEL GAS

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Discovery of natural gas in the Bay of Thailand created the opportunity for the Electricity Generating Authority of Thailand (EGAT) to reduce the importation of fuel oil which had caused an unfavorable balance of trade for the Kingdom of Thailand in the late 1970's. EGAT was the one industrial customer that had the potential to burn large quantities of the new fuel gas. Black & Veatch International (BVI) was requested to study the possibility of converting Units 3, 4, and 5 at the South Bangkok Thermal Plant to gas, oil or combination firing units.

South Bangkok

The South Bangkok Thermal Plant consists of five steam electricity generating units made up of two 200 MW units and three 300 MW units. When the original equipment was procured in the early 1970's, the possibility of natural gas being available was not envisioned and all units were designed for heavy fuel oil firing only.

BVI prepared a study addressing the various performance factors and influences of a change in the primary fuel and also made an economic analysis. The studies indicated that the fuel change was economically attractive and that the units could be readily converted for natural gas firing, although the new fuel would place some operating restrictions on the units.

It was initially anticipated that because of the low Btu content of the fuel gas, that the units would be limited in load because of high superheater and reheater metal temperatures due to the increased mass gas flow through the units. When the units were actually placed in service,
the heating value of the gas supplied was higher than anticipated. The mass flow of the combustion products was lower and metal temperatures did not become as critical as had been anticipated.

The South Bangkok units when first fired with natural gas were limited in generating capacity to about 230 MW. The limitation was caused by excessive reheat and superheat spray requirements. The gas recirculation flow was reduced to 20 per cent of original flow and the units were able to reach 300 MW with a reasonable reheat desuperheating flow.

Natural gas was fired in the first 300 MW converted unit in September, 1981. Shortly thereafter the other two 300 MW units were successfully operated on natural gas.

**Combined Cycle**

The second action taken by EGAT was to purchase eight 60 MW gas combustion turbines with associated heat recovery steam generators and two steam turbine generators to form two blocks of a combined cycle plant. This plant was located at the Bang Pakong site which is 60 kilometers south and east of Bangkok, located on the Bang Pakong river about 5 kilometers from the Bay of Thailand, near the City of Cholburi. This equipment was designed by BVI to fire either natural gas or fuel oil.

The first block of four gas turbines was delivered in early 1980. The gas turbines were installed and operating before construction started on the combined cycle plant, permitting the firing of natural gas in September, 1981 when the gas became available and providing the needed peaking capacity for the EGAT system. The first operation of the combined cycle plant as a complete entity occurred late in 1982. The second block of combined cycle plant was first operated in the second quarter of 1983. Currently Bang Pakong is the largest operating combined cycle plant in the world.
The combined cycle plant design philosophy was for a low cost peaking type of plant. In keeping with this philosophy the only heat recovery equipment in the steam cycle is the deaerator. An auxiliary dual fueled startup steam generator provides quick start capability for the steam cycle.

Both combined cycle plants are controlled from a single centrally located control room. A computerized data acquisition system is installed for ease of operation. The gas turbines were initially operated from individual local control panels.

**Thermal Plant**

EGAT's third action was to initiate purchase, engage BVI to design and to begin the construction of two 550 MW conventional gas and oil fueled units to be located at the Bang Pakong site. The thermal units are high thermal efficiency design with eight turbine extraction points for feedwater heating and steam turbine drives for the boiler feed pumps. A demineralizer provides high quality makeup water for the 2400 psig steam cycle. The surface condenser has titanium tubes for protection from the brackish Bang Pakong river water. A sponge-rubber ball condenser tube cleaning system is provided.

The forced draft fans are efficient variable-pitch axial type to maintain minimum auxiliary power requirements at all loads. The centrifugal induced draft fans are supplied with variable speed couplings for ease of control and to effect power savings at low load operation.

Unit 1 was first synchronized to the EGAT system in August, 1983 and Unit 2 will operate in mid 1984.

**Fuel Gas Operation**

During the plant design period, natural gas availability was uncertain. For this reason, all generating units were designed for both fuel oil and natural gas firing.
Shortly after fuel gas firing was initiated, foreign particles were discovered in the natural gas. This caused some erosion of the gas turbine blades and gas control valves. A natural gas scrubber was retrofitted at the Bang Pakong site to protect against the erosion. The particles consisted mainly of ferrous material picked up in the gas transmission pipeline. After initial operation, the cross country pipeline was repigged and additional gas filters were installed in the on-site natural gas system for further protection against erosion.

The natural gas control valve stations were excessively noisy at startup. After application of noise insulation and installation of an EGAT constructed silencer, the noise was reduced to an acceptable level.

EGAT has been able to fire with all of the natural gas made available to them and is eager to increase their gas usage as more gas becomes available.
COMBINED CYCLE COGENERATION

Presented at
Thailand-United States
Natural Gas Utilization Symposium
February 7-11, 1984
Bangkok, Thailand

R. I. Gavin, J. M. Osborn, W. C. Walke

Sargent & Lundy
55 East Monroe
Chicago, Illinois 60603

SARGENT & LUNDY
COMBINED CYCLE COGENERATION

R. I. Gavin/J. M. Osborn/W. C. Walke

I. INTRODUCTION

Cogeneration is generally defined as the simultaneous production of electric power and process steam in a single thermodynamic cycle. Cogeneration has long been recognized as an efficient conversion process due to its minimization of steam condensing losses and gas turbine exhaust gas losses.

The use of cogeneration cycles was extensively applied by many industries early in this century to satisfy both their power and process steam demands. However, with the extensive development of large, centralized electric power generation plants, only the most energy-intensive industries were able to economically justify onsite cogeneration due to the economies of scale associated with large central stations and the resulting low-cost electric power from electric utilities. This trend was illustrated by experience in the United States, where electric rates continued to decrease until the 1970's.

In the early '70's, however, utility rates for electric power started increasing due to increasing fuel costs (particularly liquid fuels), higher costs of capital, and additional pollution abatement control measures for coal-fired power plants. These high fuel costs and high purchased electric power costs have fostered the increased application of cogeneration facilities. This is particularly true for petrochemical and process industries, which require large quantities of process steam.

This paper will discuss the technical aspects of cogeneration cycles, cycle configurations, anticipated heat rates, construction schedules, conceptual cost estimates, and economics. Examples of the economics of cogeneration considering the lifetime generating costs are also given.

II. TYPES OF COGENERATION INSTALLATIONS

One of the main concerns in developing a cogeneration scheme is the establishment of the required ratio of electrical power to process steam. As a design basis, two classic cycles are available for producing all steam or all electric power. These are a simple boiler plant and a condensing steam turbine-generator plant, as shown in Figure 1. These cycles represent extreme noncogeneration cases producing 100% steam and 100% electrical generation.

The cycles used for cogeneration of power and steam energy have ranged between these two extremes, with the use of various combinations of condensing or noncondensing steam turbine-generators, gas turbine-generators, and waste heat recovery steam generators to meet varying electric-to-steam demand requirements.

For comparative purposes, four representative thermodynamic cycles (one noncogeneration cycle as a base case and three cogeneration cycles) are presented to illustrate available cycle configurations. Typical heat balances, estimated installed costs, construction schedules, and economics will be developed for each cycle.

The cycles chosen have a constant process steam export capability of 450,000 pounds per hour of nominal 150 psig/406°F steam output. Full condensate return from process has
been assumed at a temperature of 100°F. The level of electric power generation varies as a function of the thermodynamic cycle. The following cycle configurations will be reviewed:

Cycle 1 - simple boiler plant

Cycle 2 - boiler and noncondensing turbine-generator plant

Cycle 3 - plant consisting of a gas turbine-generator with an unfired heat recovery steam generator (HRSG)

Cycle 4 - combined cycle plant consisting of a gas turbine-generator with a supplementally fired waste heat recovery steam generator and a noncondensing turbine-generator.

Figure 2 illustrates the simple boiler noncogeneration base case (Cycle 1). Cycle equipment consists of the natural-gas-fired boiler, condensate and boiler feed pumps, and one feedwater heater - a nominal 30-psig direct contact (DC) deaerating heater. A throttling station is also included to provide 30-psig steam to the DC heater from the main steam.

Figure 3 is a schematic diagram of Cycle 2, which consists of a boiler and noncondensing turbine-generator plant. Steam conditions for this cycle are 1250 psig/900°F. Electric power production is provided by the generator associated with the noncondensing steam turbine. A nominal 150-psig DC heater uses steam directly from the noncondensing steam turbine exhaust. A desuperheating station using deaerated condensate from the DC heater is included to maintain process steam conditions.

Cycle 3, consisting of a gas turbine-generator and unfired HRSG, is illustrated in Figure 4. Exhaust gas from the gas turbine is used to produce process steam requirements in an unfired HRSG. The HRSG also produces the steam requirements for the nominal 5-psig DC heater. Electric power production occurs in the generator associated with the gas turbine. The gas turbine represents the largest frame size commercially available in the U.S. market.

The combined cycle cogeneration plant is shown in Figure 5. It consists of a gas turbine-generator, identical to that used in the previous cycle, and a supplementally fired waste HRSG. Supplemental firing is needed to produce the required steam flow at 1250 psig/900°F steam conditions to the noncondensing steam turbine-generator. All process steam is provided by the exhaust from the noncondensing steam turbine. As in Cycle 2, a desuperheating station is required to maintain process steam conditions. A 5-psig DC heater that obtains steam from a low-pressure section of the HRSG is included in the cycle. Electric power production occurs from both the gas turbine and noncondensing steam turbine; hence the term combined cycle.

Variations of power-to-steam ratio, energy conversion efficiencies, and electrical generation heat rates with nominal 84% steam credits are shown for each cycle in Table 1. The use of nominal 84% steam credits is a common method used to better reflect the value of steam production compared with that of electric power production in heat rate calculations for cogeneration cycles.

For the four cycles considered, the ratio of power to steam increases for each case, beginning with the basic noncogeneration boiler plant to the combined cycle plant. Cycle efficiency decreases in each case from the boiler plant to the combined cycle plant.
Cycle modifications, such as the inclusion of condensing turbines, can be added to increase the ratio of electric generation to steam generation. However, more condensing steam turbine-generator capacity additions to the described cycles degrade the cycle efficiency and increase the effective electric generation heat rate.

III. CAPITAL COST ESTIMATES

Conceptual cost estimates have been prepared for the four representative thermodynamic cycles based on a hypothetical semienclosed plant. A construction and engineering lead time of approximately 3 years has been assumed.

The estimated construction costs for each of the four cycles are presented in Appendix A. All material and equipment costs are based on U.S. procurement. Labor costs have been adjusted to reflect lower labor rates in Southeast Asia, with appropriate corrections for skilled craft labor as required from the United States. As shown, the estimated capital cost increases progressively from the simple boiler noncogeneration base case (Cycle 1) to the combined cycle plant (Cycle 4).

IV. ECONOMIC ANALYSIS

The economic comparison of the four gas-fired alternatives has been performed using a discounted cash flow analysis. Under this methodology, the after-tax present value of costs is determined for each alternative. The costs have been derived using parameters representative of the economic environment in Southeast Asia. The results are based on a constant dollar analysis in which all capital and operating cost cash flows are expressed in mid-1983 dollars.

The revenues derived from the sale of the final product of the production facility are not required in this economic comparison, since they are independent of the steam and electricity source selected and equal under all cogeneration alternatives. The ultimate revenues derived from the sale of the product are dependent upon international market forces and are not affected by the energy source selected. Similarly, revenues have not been included for the steam quantities supplied, since the steam outputs of each alternative are also equivalent. Therefore, the economic comparison of the alternatives is based upon the cost components that are different for each alternative.

Ultimately, an economic evaluation must be performed comparing the perceived revenues from the sale of the product with the estimated costs associated with the production and cogeneration facilities. Such an analysis is beyond the scope of this paper, and it has been assumed that the venture is profitable regardless of the cogeneration alternative.

The major cost components for each alternative include the capital-investment-related costs, natural gas costs, electricity costs, and nonfuel operation and maintenance costs. The capital-investment-related costs include the capital investment in plant and equipment, tax effects of depreciation, operating insurance, and general administrative expenses. The capital investment in plant and equipment is based upon the costs associated with the construction materials and construction, erection, and design labor. The total capital investment cost is depreciated over a 10-year period using straight-line depreciation. The annual operating insurance and general administrative expenses are each based upon 2% of the initial facilities investment. The tax effects of depreciation and the insurance and general administrative expenses have been present valued to 1983 using a 10% per year present value rate.
The natural gas fuel costs are based upon the amount of fuel consumed by each alternative, which, in turn, is based upon the configuration and efficiency of the alternative. The natural gas costs are $4.00 per million Btu in mid-1983 dollars. The configuration of the alternatives is such that the natural gas consumption increases with electrical output.

The electricity cost for each alternative is based upon a power cost of 6¢ per kilowatt hour in mid-1983 dollars and the power requirements of each alternative. The external power requirements of each alternative are based upon an assumed 125-MW demand of the production facility with a reduction by the internal generation of the alternative.

The nonfuel operation and maintenance (O&M) costs include the staff labor, maintenance materials, and operating supplies and expenses. The staff labor consists of the personnel required to operate and maintain the plant. The costs of spare parts and tools required to repair the plant during forced and scheduled outages are included in the maintenance materials costs. The operating supplies include consumables such as lubricants and chemicals.

A detailed listing of the major economic parameters used in the analysis is shown in Table 2. The parameters have been sorted by cost component. Figure 6 shows results of the discounted cash flow analysis for the base case. These results indicate that Cycle 4, the combined cycle facility, is the least expensive alternative, with an after-tax present value of costs equal to $304.57 million. The trend of the comparison indicates that as more electricity is internally generated, the after-tax present value of costs is reduced based upon the economic parameters selected for this study. This indicates that the incremental capital investment, natural gas, and nonfuel O&M costs required to produce the additional electricity are less expensive than the costs of external electricity purchases.

Sensitivity studies were performed to determine how the results vary with deviations in key cost parameters. The first sensitivity study was performed by increasing and reducing the base natural gas costs by 50%. The results are shown in Figures 7 and 8. Under this sensitivity study, only the natural gas fuel cost component of the alternatives has been changed, with the electricity costs remaining constant. The results of increasing and reducing the fuel costs indicate that Alternative 4, the combined cycle facility, is still the least expensive alternative. The effect of increasing the fuel cost by 50%, as shown in Figure 7, narrows the difference between the alternatives, since the alternatives that produce more electricity require more natural gas input. The total costs of the alternatives with greater natural gas cost components increase more rapidly due to the 50% increase in gas prices, thereby narrowing the dollar differences. Conversely, the effect of reducing the natural gas fuel cost is to widen the differences between the alternatives.

An additional sensitivity study was performed by increasing and reducing electricity costs by 50%. The resulting cost trends for the alternatives are the exact opposite of the fuel cost sensitivity. This occurs because those alternatives that internally produce substantial quantities of electricity have a small purchased power cost component and are not significantly affected, while those requiring a significant amount of purchased electricity are affected considerably. The result of increasing the electricity cost by 50%, as shown in Figure 9, increases the spread between the results. Again Alternative 4, the combined cycle facility, is the least expensive alternative. The effect of reducing the electricity cost by 50%, shown in Figure 10, narrows the cost differential and changes the results. Alternative 1, the gas-fired boiler unit, becomes the least expensive alternative, while Alternative 4 becomes the most expensive alternative.
SUMMARY

Under the economic ground rules selected for this analysis, the combined cycle plant represents the most attractive cycle. Sensitivity studies performed on major cost components also indicate that the combined cycle facility is attractive. However, individual cost analyses must be performed on a case-by-case basis to reflect the prevailing economic conditions of each specific study.
<table>
<thead>
<tr>
<th>Cycle Type</th>
<th>Cycle Power-to-Steam Ratio (kWh/$10^6$ Btu)</th>
<th>Cycle Fuel Efficiency</th>
<th>Cycle Power-Generated Heat Rate (Btu/kWh)</th>
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</thead>
<tbody>
<tr>
<td>Boiler</td>
<td>0</td>
<td>84%</td>
<td>0</td>
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<tr>
<td>Boiler/noncondensing turbine</td>
<td>57</td>
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<tr>
<td>Gas turbine/HRSG</td>
<td>195</td>
<td>74%</td>
<td>5480</td>
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<tr>
<td>Combined cycle</td>
<td>240</td>
<td>73%</td>
<td>5550</td>
</tr>
</tbody>
</table>
Table 2
Major Economic Parameters

I. General Parameters
- Commercial operation date: 1983
- Evaluation period: 15 years
- Present value rate: 10%/yr
- Operating factor: 330 days/yr
- Tax rate: 35%

II. Investment Related Parameters
- Capital investment cost ($ x 10^6) in 1983:
  - Cycle 1: 26,597
  - Cycle 2: 41,227
  - Cycle 3: 58,393
  - Cycle 4: 71,901
- Depreciation: Straight line - 10 years

III. Fuel Costs
- Natural gas price: $4/MMBtu in 1983
- Fuel consumption (10^6 MMBtu/yr):
  - Cycle 1: 4.89
  - Cycle 2: 5.87
  - Cycle 3: 9.24
  - Cycle 4: 10.26

IV. Purchased Power Costs
- Purchased power cost: $0.06/kWh in 1983
- Purchased power quantities (10^8 kWh/yr):
  - Cycle 1: 10.00
  - Cycle 2: 7.76
  - Cycle 3: 1.95
  - Cycle 4: 0.21
- Production facility electrical demand: 125 MW

V. Nonfuel Operation and Maintenance Costs
- Operating labor:
  - Skilled: 5% of total investment
  - Unskilled: $4,000/yr in 1983
  - Unskilled: $1,650/yr in 1983
Figure 1—Plant Configurations

Fuel in → Boiler → Steam turbine → Power out

Fuel in → Boiler → Condenser

Figure 2—Simple Boiler Cycle

Fuel in

Boiler

Fuel in

530,800 lb/hr
618 MBtu/hr

450,000 lb/hr
150 psig, 400°F
1,220 H

30 psig
Heater

274°F
196.3 H

80,800 lb/hr

100°F condensate from process
68 H

Auxiliary power
1.2 MW
Figure 3—Boiler/Noncondensing Turbine Cycle

- Fuel in: 565,900 lb/hr, 1250 psig, 900°F
- 1,238.4 H steam turbine
- Boiler: 1,254.8 H
- 133,000 lb/hr, 741.2 MBtu/hr
- 150 psig, 409°F
- Condensate from process 68 H
- Auxiliary power: 2.3 MW
- 17,100 to desuperheater

Figure 4—Gas Turbine/Heat Recovery Steam Generator Cycle

- Fuel in: 1,167 MBtu/hr, 1000°F
- 100 MW gas turbine-generator
- 59,900 lb/hr, 10 psig
- 5 psig heater
- Auxiliary power: 0.9 MW
- 509,900 lb/hr to process 196.3 H
Figure 5—Gas Turbine/Combined Cycle Cogeneration Cycle

1,167 MBtu/hr natural gas
Fuel in

129 MBtu/hr Suplemental fuel in

1,160.6 H
Auxiliary power
1.5 MW

1,160.6 H

1,254.8 H

100°F condensate returns
68.0 H

1,220.0 H

22.6 MW

1,250 psig, 300°F 435,200 lb/hr
10 psig 59,900 lb/hr

450,000 lb/hr 150 psig, 400°F
to process

500.4-F5
01-84--243

Figure 6—Economic Comparison of Alternatives

<table>
<thead>
<tr>
<th>Cycle</th>
<th>Nonfuel O &amp; M</th>
<th>Purchased power</th>
<th>Natural gas</th>
<th>Capital investment</th>
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</thead>
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<td>7.57</td>
<td>296.49</td>
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<td>3</td>
<td>16.40</td>
<td>57.80</td>
<td>182.78</td>
<td>61.42</td>
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<tr>
<td>4</td>
<td>20.01</td>
<td>6.11</td>
<td>202.99</td>
<td>75.46</td>
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</table>
Figure 7—Economic Comparison of Alternatives

Sensitivity study—increase natural gas costs 50%

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<tr>
<th>After-tax present value of costs ($x 10^6)</th>
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<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
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<tbody>
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<td>477.19</td>
<td>509.78</td>
<td>406.06</td>
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<tr>
<td>458.99</td>
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<td>409.78</td>
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<tr>
<td>406.06</td>
<td></td>
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</tbody>
</table>

Total after-tax present value of costs by cost component

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
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<td>Nonfuel O&amp;M</td>
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<td>11.46</td>
<td>16.40</td>
<td>20.01</td>
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<tr>
<td>Purchased power</td>
<td>296.49</td>
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<td>57.79</td>
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</tr>
<tr>
<td>Natural gas</td>
<td>145.19</td>
<td>174.09</td>
<td>274.17</td>
<td>304.48</td>
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<tr>
<td>Capital investment</td>
<td>27.94</td>
<td>43.20</td>
<td>61.42</td>
<td>75.46</td>
</tr>
</tbody>
</table>

Figure 8—Economic Comparison of Alternatives

Sensitivity study—reduce natural gas costs 50%

<table>
<thead>
<tr>
<th>After-tax present value of costs ($x 10^6)</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>380.40</td>
<td>342.93</td>
<td>203.07</td>
<td></td>
<td></td>
</tr>
<tr>
<td>342.93</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>227.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>203.07</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total after-tax present value of costs by cost component

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nonfuel O&amp;M</td>
<td>7.57</td>
<td>11.46</td>
<td>16.40</td>
<td>20.01</td>
</tr>
<tr>
<td>Purchased power</td>
<td>296.49</td>
<td>230.24</td>
<td>57.79</td>
<td>6.11</td>
</tr>
<tr>
<td>Natural gas</td>
<td>48.40</td>
<td>58.03</td>
<td>91.39</td>
<td>101.49</td>
</tr>
<tr>
<td>Capital investment</td>
<td>27.94</td>
<td>43.20</td>
<td>61.42</td>
<td>75.46</td>
</tr>
</tbody>
</table>
Figure 9—Economic Comparison of Alternatives

Sensitivity study—increase purchased power costs 50%

After-tax present value of costs ($ x 10^6)

<table>
<thead>
<tr>
<th>Cycle</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>516.08</td>
<td>347.29</td>
<td>307.62</td>
</tr>
<tr>
<td>2</td>
<td>577.03</td>
<td>307.62</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total after-tax present value of costs by cost component

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nonfuel O&amp;M</td>
<td>7.57</td>
<td>11.46</td>
<td>16.40</td>
<td>23.01</td>
</tr>
<tr>
<td>Purchased power</td>
<td>444.73</td>
<td>345.36</td>
<td>86.69</td>
<td>9.16</td>
</tr>
<tr>
<td>Natural gas</td>
<td>96.79</td>
<td>116.06</td>
<td>182.78</td>
<td>202.99</td>
</tr>
<tr>
<td>Capital investment</td>
<td>27.94</td>
<td>43.20</td>
<td>61.42</td>
<td>75.46</td>
</tr>
</tbody>
</table>

Figure 10—Economic Comparison of Alternatives

Sensitivity study—reduce purchased power costs 50%

After-tax present value of costs ($ x 10^6)

<table>
<thead>
<tr>
<th>Cycle</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>280.54</td>
<td>285.84</td>
<td>289.50</td>
</tr>
<tr>
<td>2</td>
<td>285.84</td>
<td>289.50</td>
<td>301.51</td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total after-tax present value of costs by cost component

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nonfuel O&amp;M</td>
<td>7.57</td>
<td>11.46</td>
<td>16.40</td>
<td>20.01</td>
</tr>
<tr>
<td>Purchased power</td>
<td>148.24</td>
<td>115.12</td>
<td>28.90</td>
<td>3.05</td>
</tr>
<tr>
<td>Natural gas</td>
<td>96.79</td>
<td>116.06</td>
<td>182.78</td>
<td>202.99</td>
</tr>
<tr>
<td>Capital investment</td>
<td>27.94</td>
<td>43.20</td>
<td>61.42</td>
<td>75.46</td>
</tr>
</tbody>
</table>
### Appendix A

#### Conceptual Cost Estimate for Cogeneration Cycles

**General Data**

<table>
<thead>
<tr>
<th>Description</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gas-fired steam generators</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number</td>
<td>1</td>
<td>1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity (lb/hr, each)</td>
<td>535,000</td>
<td>570,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Steam pressure and temperature</td>
<td>150 psig/406°F</td>
<td>1250 psig/900°F</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Heat recovery steam generators</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Capacity (lb/hr, each)</td>
<td>-</td>
<td>-</td>
<td>515,000</td>
<td>500,000</td>
</tr>
<tr>
<td>Steam pressure and temperature</td>
<td>-</td>
<td>-</td>
<td>150 psig/406°F</td>
<td>1250 psig/900°F</td>
</tr>
<tr>
<td><strong>Turbine-generators</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Back pressure (noncondensing)</td>
<td>Not required</td>
<td>Not required</td>
<td>Not required</td>
<td>Not required</td>
</tr>
<tr>
<td>Number</td>
<td>-</td>
<td>1</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Nominal gross rating-MW</td>
<td>-</td>
<td>30</td>
<td></td>
<td>30</td>
</tr>
<tr>
<td><strong>Condensing</strong></td>
<td>Not required</td>
<td>Not required</td>
<td>Not required</td>
<td>Not required</td>
</tr>
<tr>
<td>Number</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Nominal gross rating-MW</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Combustion gas</strong></td>
<td>Not required</td>
<td>Not required</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Nominal ISO rating-MW</td>
<td>-</td>
<td>-</td>
<td>100.0</td>
<td>100.0</td>
</tr>
<tr>
<td><strong>Fuel required (Btu/hr x 10^6)</strong></td>
<td>618</td>
<td>741</td>
<td>1167</td>
<td>1296</td>
</tr>
</tbody>
</table>
Appendix A

Conceptual Cost Estimate for Cogeneration Cycles

Cost Data

<table>
<thead>
<tr>
<th>Description</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Boiler</td>
<td>Boiler/Noncondensing</td>
<td>Gas Turbine/HRSG</td>
<td>Combined Cycle</td>
</tr>
<tr>
<td>Structural</td>
<td>$3,562,000</td>
<td>$5,583,000</td>
<td>$6,061,000</td>
<td>$7,740,000</td>
</tr>
<tr>
<td>Mechanical</td>
<td>11,295,000</td>
<td>18,685,000</td>
<td>28,837,000</td>
<td>35,587,000</td>
</tr>
<tr>
<td>Electrical</td>
<td>1,895,000</td>
<td>2,453,000</td>
<td>3,564,000</td>
<td>4,374,000</td>
</tr>
<tr>
<td>Subtotal</td>
<td>$16,752,000</td>
<td>$26,721,000</td>
<td>$38,462,000</td>
<td>$47,701,000</td>
</tr>
<tr>
<td>Contingency (20%)</td>
<td>3,350,000</td>
<td>5,344,000</td>
<td>7,692,000</td>
<td>9,540,000</td>
</tr>
<tr>
<td>Total estimated construction cost</td>
<td>$20,102,000</td>
<td>$32,065,000</td>
<td>$46,154,000</td>
<td>$57,241,000</td>
</tr>
<tr>
<td>Indirect costs</td>
<td>4,390,000</td>
<td>7,002,000</td>
<td>10,079,000</td>
<td>12,500,000</td>
</tr>
<tr>
<td>Allowance for housing</td>
<td>2,000,000</td>
<td>2,000,000</td>
<td>2,000,000</td>
<td>2,000,000</td>
</tr>
<tr>
<td>Allowance for transfer of knowledge</td>
<td>50,000</td>
<td>50,000</td>
<td>50,000</td>
<td>50,000</td>
</tr>
<tr>
<td>Land acquisition</td>
<td>55,000</td>
<td>110,000</td>
<td>110,000</td>
<td>110,000</td>
</tr>
<tr>
<td>Grand total estimated cost</td>
<td>$26,597,000</td>
<td>$41,227,000</td>
<td>$58,393,000</td>
<td>$71,901,000</td>
</tr>
</tbody>
</table>

Annual cash flow

<table>
<thead>
<tr>
<th>Year</th>
<th>Cycle 1</th>
<th>Cycle 2</th>
<th>Cycle 3</th>
<th>Cycle 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>1984</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>1985</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>1986</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>1987</td>
<td>$2,823,000</td>
<td>$3,312,000</td>
<td>$3,737,000</td>
<td>$4,204,000</td>
</tr>
<tr>
<td>1988</td>
<td>6,843,000</td>
<td>11,826,000</td>
<td>21,045,000</td>
<td>25,085,000</td>
</tr>
<tr>
<td>1989</td>
<td>13,690,000</td>
<td>21,070,000</td>
<td>27,026,000</td>
<td>33,970,000</td>
</tr>
<tr>
<td>1990</td>
<td>3,241,000</td>
<td>5,019,000</td>
<td>6,585,000</td>
<td>8,642,000</td>
</tr>
<tr>
<td>Total</td>
<td>$26,597,000</td>
<td>$41,227,000</td>
<td>$58,393,000</td>
<td>$71,901,000</td>
</tr>
</tbody>
</table>
Appendix A

Conceptual Cost Estimate for Cogeneration Cycles

NOTES
1. Commercial operation date is January 2, 1990.
2. The project contingency is 20% of the total estimate cost.
3. All material and equipment costs are based on U.S. procurement.
4. All material and equipment costs are F.O.B. site.
5. All costs are based on competitive bidding.
6. Exclusions: Costs for the following items have not been included.
   - Process plant modifications
   - Steam and condensate distribution piping within the process plants
   - Tie-ins with process plant, except process steam and condensate lines to the battery limit of associated plant
   - Facilities not located on the plant site, except allowance for housing
   - Permanent plant staff costs, including operator's training and manuals
   - Inventory costs
   - Allowance for funds used during construction (AFDC)
   - Escalation.
Since 1850, energy supply sources have changed dramatically and this trend is expected to continue for the next 100 years. For example, in 1850, the United States derived 75% of its energy from wood, more than 15% from water and wind, and less than 1.0% from coal.

Fifty years later, in 1900, energy from coal had increased to 75% and wood's share had declined to 20% of total supply.

Another dramatic shift took place during the next 70 years. By 1970, petroleum and natural gas accounted for 75% of total energy supply compared with only 20% from coal.

During the next 50 years, further significant changes in energy supply are forecast. The portion of energy supplied from crude oil and natural gas will diminish substantially while energy's share from coal, shale oil, tar sands and nuclear power will increase significantly. The age of synthetic fuels, however, is expected to be brief because of the advent of "clean" nuclear energy from fusion and harnessing energy from our own sun.

Some experts believe that during the second half of the 21st century, more than 90% of the world's energy supply will be fusion and solar.

The significance of the foregoing as well as other factors that I will elaborate on serve to make it logical and rational for Thailand to consider a policy of immediate utilization rather than conservation or restricted application of this valuable indigenous resource.
When a temporary world wide shortage of energy at the end of 1973 and the beginning of 1974, many prominent economists called for restricting the use of natural gas solely as a chemical feedstock and proclaimed that it was unconscionable to burn it as fuel. I disagree with this view. I believe that any indigenous natural resource should be utilized for whatever applications that will most benefit a nation's economy and create the largest number of meaningful jobs.

Before discussing a number of direct heating applications for natural gas, let us put Thailand's natural gas reserves into perspective. Thailand's estimated proved gas reserves as of January 1, 1982, amounted to 12 trillion cubic feet (TCF).\(^1\) This is equivalent to approximately 2.2 billion barrels of crude oil. This compares with proved natural gas reserves of 198 TCF in the United States. Only four Asian countries have larger reserves (China, Indonesia, Malaysia and Pakistan) whereas India's reserves are about equal to those of Thailand. Excluding Communist areas, the Middle East and North Africa, Thailand's reserves amount to 1.5% of the world's total.

Thailand's present consumption of oil is about 250,000 B/D or equivalent to about 0.5 TCF per year of natural gas. If 90,000 B/D of oil is replaced by natural gas, and assuming an annual increase in demand of 10%, then the 12 TCF reserves will last 21 years. However, if the increase in demand for oil is 12% per year and if Thailand starts to replace 125,000 B/D of oil by natural gas, then the 12 TCF reserve will be consumed in about 16 years.

\(^1\)For simplicity, it is assumed that 1 TCF (or \(10^{12}\) cubic feet) of gas is equivalent to 1 Quadrillion BTU's and equivalent to 183 million barrels of crude oil.
The depletion of Thailand's natural gas reserves within two decades should be no cause for alarm if it is used to speed up industrialization and create meaningful jobs. In this connection, it should be noted that the United States consumes 20 TCF per year of natural gas amounting to 28% of total energy demand. At the present rate of consumption, existing proved reserves will be exhausted in 10 years.

Regardless of which yardstick is used to measure the size of Thailand's gas reserves, the only conclusion that can be drawn is that it is a very valuable resource and its consumption must be planned to give the maximum economic benefit to the Thai people.

Many top government officials, leading economists and prominent businessmen are evaluating Thailand's options in the development of natural gas. I will, therefore, not be so presumptuous as to make recommendations. I can, however, summarize the more important applications of natural gas in the United States industry because, in some cases, a parallel can be drawn.

Since the use of gas in the power generating, the chemical and the petroleum industries is discussed by others at this Symposium, I will restrict my remarks to the use of gas for direct heating in other industrial applications.

Apart from space heating and the generation of electric power, the largest consumer of gas in the United States in 1981 were the following industries:

<table>
<thead>
<tr>
<th>Industry</th>
<th>1981 Consumption in TCF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>1.812</td>
</tr>
<tr>
<td>Petroleum and Coke</td>
<td>0.701</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>0.649</td>
</tr>
<tr>
<td>Food</td>
<td>0.397</td>
</tr>
</tbody>
</table>

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The above industries consumed a total of 6.82 TCF of natural gas or about 34% of total gas consumption in the United States. Electric power generation accounted for an additional 3.93 TCF or nearly 20% of consumption.

With the exception of cement and paper, natural gas was the predominant fuel used by all of the above industries. Overall, of the 22 Quads of BTU's of energy (equivalent to 22 TCF of natural gas) consumed by United States industries in 1981, natural gas accounted for 49% of the total compared with 37% for oil and 14% for coal.

The United States steel industry consumed 0.65 TCF of natural gas in 1981 but very little was used for direct reduction of iron ore. This use of natural gas is becoming more prevalent in areas of the world that have inexpensive and abundant gas. Principal use of gas in the United States iron and steel industry is for pelletizing, blast furnace injection, boilers, open hearth melting, soaking pits, reheat furnaces, annealing furnaces and atmosphere generators.
Natural gas supplies over half of the energy requirements of the food industry and 70% of that is used to fire boilers for steam processes and power generation. Natural gas is the only fuel for many drying and baking applications and cannot be replaced without converting these units to indirect firing. Gas is the only fuel clean enough to contact food products directly. During 1981, 0.346 TCF was consumed principally for boilers, dryers, baking ovens, candy stoves, coffee roasters and fryers.

The paper industry consumes 2 TCF of energy annually, but nearly 50% of this is generated from waste material. Since 1972 the industry has decreased the use of gas and oil by converting boilers to waste product or to coal firing. During 1981, the paper industry consumed 0.341 TCF of natural gas and major fuel applications were boilers, strip dryers and drying cans.

Non-ferrous metals consumed 0.332 TCF of natural gas in 1981. Major applications consisted of calcining kilns, electrode furnaces, roasters, smelters, crucible melters, ladle heaters, core ovens, dye casters, shell molders, forging furnaces and annealing furnaces.

Fabricated metal products consumed 0.233 TCF of natural gas in 1981, accounting for 49% of total energy consumption in this industry. Principal applications were heat treating furnaces, paint drying ovens, brazing furnaces, flame cutting and core ovens.

Glass products consumed 0.161 TCF of natural gas in 1981 accounting for 79% of energy consumption in this industry. Principal applications are glass melters, containing forming machines, bulb forming machines, fire polishing, annealers, forming furnaces and fiberglass curing ovens.
Transportation equipment consumed 0.135 TCF of natural gas in 1981 accounting for 37% of the energy used in this industry. Major applications are the same as for iron and steel and fabricated metal products. Another application which may grow significantly in the coming decade is the use of natural gas as an automatic fuel, a much less expensive alternative than a rechargeable electric car.

Most of the energy used by the clay products industry is for the manufacture of building brick, structural clay tile and sewer pipe. Energy consumption varies widely from year to year depending upon the condition of the housing industry. In 1972, 0.154 TCF was used compared to 0.084 TCF in 1981 due to recession in the housing industry. Principal applications are clay and tunnel dryers and various kinds of kilns.

The textile industry consumed 0.056 TCF of natural gas in 1981 amounting to 37% of total energy used in this industry. Principal applications were boilers, tentor frame dryers, calendar rolls, ink dryers and dye vats.

In 1974, natural gas accounted for 45% of total energy used in the cement industry. Since then, coal use has increased dramatically in response to natural gas price increases. Coal enjoys a premium because the ash increases product output. Air pollution advantage of natural gas has little effect on particulate emission. By 1981, consumption for this application declined from 0.201 TCF in 1974 to 0.037 TCF in 1981 representing only 20% of the energy used for this application.

From the foregoing, it can be concluded that natural gas in Thailand can play a very important role in industrial development as well as power generation. In deciding how best to utilize this valuable indigenous resource,
Thailand should carefully weigh the economics of in-country consumption for industrial development and job creation versus exporting its gas in the form of LNG as some of its neighbors are doing or are planning to do. Since natural gas is one of the cleanest forms of energy and can be used in a variety of different industries prudent management of this resource is an absolute necessity.
ENERGY SUPPORT SERVICES, INC.

PROFILE

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ESSI's clients include Houston Light and Power Company, Mississippi Power and Light, Carolina Power and Light, Exxon, Arco and the Ministry of Defense and Aviation in Saudi Arabia.

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        Asheville, North Carolina 28816
        Tel. (704) 258-8888
NATURAL GAS RECIPROCATING ENGINES IN ON-SITE POWER PLANTS

BY

DAVE NOELKEN

SENIOR APPLICATION ENGINEER

CATERPILLAR TRACTOR CO.

THAILAND-UNITED STATES NATURAL GAS UTILIZATION SYMPOSIUM AND FIELD TRIP

FEBRUARY 7-11, 1984.

BANGKOK, THAILAND
1. Good afternoon ladies and gentlemen. It is an honor to address such a distinguished symposium as has gathered here today. As all are aware, Thailand is undergoing a very unique era concerning her energy needs and requirements.

With steady industrial development, Thailand's energy requirements grew at the rate of 7.6% annually between 1978-1981.

Because of escalating oil prices, the need has been obvious to expedite the search for alternative future sources of energy to slow the drain on the Thai economy from imported oil. The Thai Government has encouraged energy conservation and at the same time stepped up exploration for oil and gas. By 1982, the growth in energy consumption dropped 5.4%.

Simultaneously, recent discoveries of natural gas resources have been found off the Gulf of Thailand, with reserves estimated to contain about 16 trillion cubic feet of gas. Some of this gas is already being used and has reduced oil imports to only 61% of 1982 levels -- a 12.8% reduction.

With continued exploration in the Sirikit field, and increased gas production in the future, it is estimated that Thailand will need to import slightly less than half of her energy requirements by 1986.
The natural gas can be burned in reciprocating engines to produce a reliable source of power. Simultaneously, hardware exists today that can be used to recapture waste heat from the generator set for thermal needs. Reciprocating generator sets as such provide an economically viable use for a portion of this gas from the Gulf of Thailand. On-site generating systems under 1 MW applied in commercial and light industrial installations can provide a source of electricity for the end user and provide load management for each of the three state utilities. Bringing these natural gas reserves into full production for commercial and light industrial needs is our area of mutual interest this afternoon.

2. Since most of us are familiar with diesel engines, let's begin by comparing them with natural gas engines. Basically, these two types of engines have different design limitations. Diesels are theoretically limited by the mechanical loading of components such as bearings, crankshafts and head bolts. Gas engines, on the other hand, are thermally limited by combustion temperatures which affect valves, piston rings and piston crowns. Gas engines work on a constant air-fuel ratio throughout the load range and do not have excess air to assist with cooling as do diesels.
3. These facts force gas engine manufacturers to make a choice in the basic engine design stage. Build a structurally lighter engine with the capability to handle the higher thermal loads? Or, retain the inherent diesel structural strength and add special components as required to perform under the higher gas engine combustion temperatures?

At Caterpillar we choose to build natural gas engines with most of the same basic components as our diesels, even though the gas engines operate at lower compression ratios and at peak pressures 40-50% less than the diesels. Only combustion area components such as pistons and valves are different to accommodate the higher temperatures. Superior durability results, with over 80% parts commonality between corresponding gas and diesel models.

4. The gas engines differ from their diesel counterparts in three basic functional areas:

1) Fuel system
2) Ignition system
3) System compression.

Understanding these basic differences is fundamental when discussing diesel and gas engines.
5. The combustion method differs in that the diesel, shown on the left, utilizes compression ignition to initiate the burning process. Pure fuel is injected to the cylinder by the fuel pump and the intake valve introduces air. Ignition occurs when the piston moves upward, compressing the fuel/air mixture until heat of compression ignites the charge.

The gas engine, shown on the right, relies on a spark plug to ignite the fuel/air mixture in the cylinder, just like your automobile engine. The fuel/air mixture enters the cylinder thru the intake valve. Ignition occurs as the piston approaches the top of the cylinder and the spark plug fires.

6. The gas and air are mixed together in a carburetor such as this prior to entering the cylinders. This Impco valve-type carburetor provides constant mixing over a broad operating range, requires no choking on start-up and offers reliable service.

7. A gas engine ignition system consists of a low voltage electrical generator, a transformer at each cylinder to raise the voltage and finally the spark plug itself. Solid-state spark ignition systems are now widely used since the electronic switching of current ensures ignition at peak combustion chamber pressures.
8. Most gas engine manufacturers, including Caterpillar, offer high and low compression ratio engines allowing use of a wide variety of fuels. When the high compression ratio (10:1) is used, the number of gaseous fuels which can be utilized is limited; but the specific fuel consumption (fuel consumption rate) is low. Conversely, the low compression ratio (7:1) engines have a higher specific fuel consumption; but they can use a broader range of fuels.

9. As we know from diesel engines, turbocharging and aftercooling permit increased power in a smaller, lighter package than naturally aspirated engines. Owning costs are lowered since "smaller" is generally less expensive.

10. Now let's take a look at some of the fuel gases which you might consider as energy sources. Dry natural gas is a mixture of methane, ethane, not more than 5% propane, and a fractional percentage of butane. It can also be referred to as commercial pipeline natural gas. We could define this as a preferred fuel gas.

The term "dry" refers to the absence of petroleum products such as butane or propane which become liquid under pressure at typical ambient temperatures.
The Btu content of dry gas varies. Caterpillar Gas Engines are factory adjusted and rated with a dry natural gas having a low heat value of 905 Btu/cu.ft.

11. Propane of at least 95% purity (the remaining 5% not being heavier than butane) which meets specification HD-5 can be used in all types of engines when the necessary adjustments are made. These adjustments may consist of carburetor and ignition timing changes. High compression engines using this fuel are limited to nonlug applications such as centrifugal pumps and generator sets. Propane and butane are heavier than air so proper engine room ventilation is of major importance.

12. Butanes are recommended only for low compression ratio, naturally aspirated gas engines. Timing must be retarded from that recommended for natural gas.

13. Field gas is the gas available at the wellhead in a gas field. It is also referred to as "wellhead" gas. Some of this gas may have undesirable components such as sulfur. In those instances, fuel treatment must be used. Oil changes should also be made more often, and lube oil samples should be analyzed regularly. The composition of field gas varies widely between gas fields. A gas analysis is required to determine suitability of the fuel.
14. Sour gas contains the impurity hydrogen sulfide (H₂S). Salt may also be present in this field gas. Both of these impurities can harm the engine. Special considerations must be made if more than a trace is present. Hydrogen sulfide levels greater than 0.1% by volume must be treated to lower the H₂S level below 0.1%.

15. At the present time, there are thousands of Caterpillar natural gas engines in operation around the world. Application areas include electric power generation, irrigation, sewage treatment, petroleum recovery, refining and distribution. These engines shown are operating on a variety of fuel gases including dry natural gas, wellhead gas and even sewage gas. For the next few minutes, let's look at some examples of gas engines at work.

16. This is a 3306 NA gas engine rated 130 hp driving a deep well pump to supply water for irrigation in the United States. The 90 degree gear head behind the engine changes the direction of the power flow from the engine to the pump. These gear heads are available in a wide range of gear ratios from auxiliary equipment manufacturers.

17. In this slide, 3-G398 industrial engines producing over 400 hp each are driving water pumps in a public water supply system.
18. Here, 5-G398 engines drive AC generators to produce electrical power for a
beef packing operation.

19. This particular industrial application includes 4 separate natural gas
engines. 3-G398 industrial engines drive air compressors while 1-G342
generator set in the foreground provides electrical power.

20. This postal office in the United States relies on gas engines for all of
its' electrical power and some heating.

21. 5-G398 generator sets rated 500KW each supply all of the electrical energy
requirements and also make use of engine jacket water waste heat to supply
a portion of the buildings heating requirements.

22. We mentioned petroleum applications earlier. Here is a G398 industrial
engine driving a gas compressor package. The compressor is an integral
part of a transmission system. Note the remote location. The large
radiator is used to cool both the engine jacket water and the compressed
gas. Special components such as gas compressors and radiators are not
available from Caterpillar, but are sourced from other manufacturers.

23. This G342 industrial engine is driving a pump at a water-injection project
in a petroleum application.
24. Before moving away from the subject of applications, I would like to say a few words about the use of reciprocating natural gas engines versus gas turbines. As you are now aware, Caterpillar builds reciprocating gas engines in the 100-1,000hp range. But thru our Solar Turbines Division, we also build gas turbines in the 1,000 to 12,000 hp range.

Each type of engine has its own merits. We suggest you consider the following points when choosing between reciprocating engines or turbines in the 1000 hp range:

- thermal efficiency expectations - 30% recip/15% turbine
- fuel gas quality - turbines more sensitive
- actual power requirement - recips limited over 1,000 hp
- local maintenance costs - turbine could be higher
- purchase price
- weight limitations - turbine generally lighter
- availability of qualified operations personnel.

25. All of the applications discussed so far have been straightforward systems which utilized only the engines flywheel horsepower. Now let's look at a more advanced concept which can make gas engines even more economical.
26. **COGENERATION** - Cogeneration is defined as:

The simultaneous production of electrical and/or mechanical power and useful thermal energy by utilizing internal combustion engines or turbines.

To understand this concept, we need to examine the efficiency of the reciprocating engine.

27. This is a typical breakdown of what happens to fuel burned in a reciprocating engine:

- About 33% of the fuel's energy is converted to flywheel horsepower.
- Approximately 30% of the fuel's energy is rejected to the jacket water cooling system.
- 30% is expelled by the exhaust.
- Approximately 7% is radiated as heat from the engine surfaces.

As energy costs continue to rise, the economics of recovering the wasted heat have become increasingly attractive.
28. By capturing the jacket water heat, the fuel energy utilization increases from about 33% to over 60%. Of the 30% energy which is lost through the exhaust system, about one-half can be captured thru the use of heat recovery mufflers. Utilization of the flywheel horsepower output plus jacket water and exhaust heat can bring engine efficiency into the range of 70-80%.

This recovered heat can be used in many ways:

- domestic hot water supply
- laundries
- washing units
- boiler feed preheating
- process heating for liquids other than water
- combined steam systems with absorption air conditioning.
- industrial or agricultural drying processes.

29. The benefits of cogeneration can be summarized in these six points:

1) Increased efficiency -- cogeneration saves money by using the same fuel to produce two forms of useful energy.
2) Reliable source of power -- generating one's own electricity can mean having power when you need it.

3) Beneficial for environment -- greater efficiency can mean less pollution.

4) Lower utility costs -- generating one's own electricity can mean purchasing less from utilities.

5) Good investment -- cogeneration facilities can yield a high rate of return on one's investment.

6) Reduce dependence on foreign oil -- generating electricity on site with natural gas can save thousands of barrels of oil a year.

30. Let's look at a hypothetical light industrial customer who presently has an electrical demand of 1,000 kW with a corresponding requirement for hot water for an industrial process. Presently, he buys electricity from the public utility at 1.38 Bht/kW H ($0.06 U.S.). In addition, natural gas is consumed in a 75% efficient boiler and is purchased at 92 Bht ($4.00 U.S.)/(1,000,000 Btu). Operation is 330 days per year -- 24 hours per day.
For straight on-site power generation and assuming 9.2 baht/100,000 BTU, for natural gas, the customer's cost per kW-hr would be approximately 1.28 Bht (including maintenance at 0.1725 Bht/kW/hr) at 100% load. This increases up to 1.45 Bht/kW/hr at a 50% load factor on the generator set. (refer to chart)

Let's assume the thermal load could be supplied by the heat in the jacket water circuit. Because this heat must be dissipated, notice the affect by using this heat in a simple heat exchanger vessel. Effective power generation costs would be 0.95 Bht/kW/hr at 100% and 1.00 Bht./kW-hr at a 50% load factor. (refer to chart)

We can go one step further by also using the waste heat from the exhaust. We could use this heat by introducing the exhaust heat in series after recapturing the jacket water heat. This further enhances the economies of power generation down to 0.7935 Bht/kW/hr at 100% and only 0.69 Bht/kW/hr at 50% load factor. (refer to chart)

31. Although the benefits from using on-site generating systems are substantial, suppliers of equipment must be interested in developing systems which provide true economic value. Important system considerations are:
- The amount of electrical demand.
- The amount of heat required.
- The amount of heat available
- Present and projected costs of power and heat.
- Projected cost of on-site generation power and heat.
- Cost of supplementary power supplied by the utility.
- Tax environment
- Cost and availability of fuel for on-site generation.

32. The principal benefit to look for in cogeneration is, of course, a reduction in total energy cost. Remember, the idea is to generate electricity and usable heat in a more efficient, cost-effective manner.

33. There is a tool available from Caterpillar to help determine the economic feasibility of cogeneration.

The On-Site Power, Cost Feasibility Analysis is a computer program which performs a complete cash flow analysis for individual applications. Using basic cost information, this program will give an accurate estimation of projected cash flow for a specified number of years for these sophisticated systems. It takes into account tax rates, depreciation methods, investment tax credits and the cost of borrowing capital for the investment. The final output will be a payout period in years for the cogeneration plant to pay for itself and a rate of return on owners investment.
But before leaving the subject of cogeneration, a few words of caution.

A true cogeneration installation is a sophisticated engineering system. The gas engine and generator become a relatively minor portion of the total installation. Owners of cogeneration systems must be prepared to deal with:

- heat recovery systems
- water treatment
- valving
- pumps and piping
- condensers
- protection devices
- system controllers
- switchgear

Competent operations personnel and a fully qualified, technically capable system supplier are necessities. The financial rewards from a cogeneration system can be very attractive, but only if the system is professionally designed, installed and operated.
35. One final concept I would like to introduce today is **Peak Shaving**.

Peak shaving is defined as "a reduction of peak electrical power demands on public utility systems by utilizing alternate power sources".

The alternate power source in the context of our discussions would be a natural gas powered generator set. It might be a unit specially purchased to handle peak shaving or, less common for a gas fueled system, a standby generator set which provides a peak shaving function during periods of regular power supply from the utility.

36. This is a typical 24-hour electrical load profile based on a 12-hour workday. A vast majority of power is used on this basis. The utility electric rates generally increase as the kilowatt demand increases and rates may also vary according to the time of day.

The objective of peak shaving is for the user to generate his own less expensive electrical power on-site during the peak demand periods, rather than paying the high utility rates.
37. Peak shaving, when properly practised, can:

- assure power for critical operations
- reduce energy costs
- increase use of expensive standby equipment which might otherwise be idle
- increase reliability of the on-site generating system due to the regular utilization and care.

38. Which applications might benefit the most from peak shaving?

Basically, these would be applications with a high energy input to production output ratio. Ideal candidates would be those requiring large amounts of energy over very short periods of time, thereby causing spikes in demand. For example:

- Food and kindred products
- Textile Mill Products
- Lumber and Wood Products
- Paper and Allied Products
- Printing and Publishing
39. There are several characteristics of a customer's power usage which make peak shaving more economically attractive.

A. There must be a definite peak.

B. The peak should be at least three times greater than the base load.

C. The peak load lasts less than ten hours per day.

D. The peak demand is greater than 1000 KW.

Keep in mind these are general guidelines and each case should be analysed in depth due to the variety of utility rate structures.
Generally, the more of these characteristics that are displayed in the load profile, the greater opportunity for peak shaving to pay for itself.

Diesel engines are more commonly found in standby generator applications. But if a gas generator set is purchased for standby power, the return on investment can be greatly enhanced if it is used to peak shave. The additional investment needed for peak shaving may be small compared to the potential savings. Basically, greatest kW demand reduction with fewest number of operation hours results in greatest savings.

40. In summary, there is a significant and growing opportunity for Thailand to take positive approaches to improve her current energy situation. Precious natural gas reserves can serve many useful purposes by providing load management to the utilities and reduced energy charges for many sectors of the Thai economy. Through the prudent use of natural gas, petroleum imports can be reduced, easing the outflow of GNP earnings, thereby allowing Thailand to better compete in the world marketplace.

These are truly unique times for those of us involved with energy in Thailand -- times which call for careful consideration of all potential energy sources.
Based on:

(1) 1000 kW electrical requirement

(2) Natural gas cost of 9.2 baht per 100,000 BTU
GAS TURBINES FOR INDUSTRIAL USE

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In order to select a driver most suited to the requirements in industrial use, the basics of industries and available driver types must be fully understood. The characteristics of the process in which the driver must perform should be understood and process and driver must match. In essence the driver must fit the process characteristics. Consideration must be given to proper coordination of driver and driven equipment, and the effects of the operating environment should be fully studied. A proper selection of equipment with these facts known and considered will provide the most economical and reliable installation.
Drivers of various types are used in virtually every industry. These industries include those in which gas turbines are predominantly, or frequently encountered as the prime movers of major equipment. Combustion gas turbines will be found in gas pipelines, oil pipelines, oil production, gas treatment, gas gathering, gas storage, refining, tanker unloading, air separation, LNG production, blast furnace, power generation and others. They are also used frequently for ship propulsion.

In order for a potential user to decide on the optimum driver for the application, a review of the available drivers is generally advisable. It is at this stage that the operating characteristics and common uses for the various types must be studied. A brief review of driver types, their characteristics and common applications follows:

1. **Steam Turbines**

Steam turbines are suitable for a wide variety of pump, compressor and generator applications. They can be geared or direct coupled to driven equipment, and can be readily sourced in a range of very small power to 60,000 KW for mechanical drive applications, and approximately 1400 MW for power generation. Larger units are available but are not common.

The flexibility of speed is inherently a steam turbine feature. They can be designed for 1500 RPM to 35,000 RPM and generally have a variation capability of 25% to 105% of design speed.

Large amounts of purified water and steam producing boilers are required. This is one main consideration as the application for such turbines must be located where this energy source is available.

2. **Electric Motors**

Motors of both induction and synchronous types are available in fractional power ratings to 25,000 KW and larger. They are available from low speeds (180 RPM) to a maximum of 3600 RPM, and with the exception of wound rotor motors or variable frequency control systems, are fixed speed drivers.

Motors can be direct coupled, geared, belted or otherwise configured to the driven equipment. They require an appropriate amount of electrical power and load/starting requirements in the process usually play a significant role in selection of motors for drivers.
3. Industrial Engines

There are several types of diesel or gas industrial engines, ranging in size from approximately 50 KW to 1000 (M) KW and speeds from 300 RPM for large power units to 3000 RPM for smaller units. Speed variation typically ranges from 60% to 100% of the rated speed. Engines are usually available as drivers to be direct coupled to driven equipment or as an integral unit with a compressor. There are additionally many applications where gearing is effectively utilized.

Industrial engines are most suitable when gaseous fuels are readily available. This, of course, is the engine energy source. They are considerably more efficient than combustion gas turbines and suit well applications where fuel supply is limited or costly. An engine, partially damaged is usually capable of partial delivery of product, where a combustion gas turbine is not. Additionally, they require little or no electrical support and are therefore suitable for applications where electrical power is limited or where it is unreliable.

A major consideration when selecting an industrial engine is the anticipated duty it will be subject to. Continuous operation requires substantial derating of higher speed units (greater than 1000 RPM). Failure to do so will cause increased downtime and require extensive maintenance. The availability of qualified and capable maintenance personnel is a vital factor in the use of industrial engines. Users generally install a back-up engine due to frequent maintenance requirements.

4. Liquid (Hydraulic) Turbines

The liquid, or hydraulic turbine is simply, or effectively a reverse rotation pump. These machines can be custom built over a wide speed and power range, and require only a liquid at some differential pressure. This pressure can be obtained statically or dynamically, but is common only where liquid is flowing from a higher to a lower elevation, such as a waterfall.

5. Gas Expanders

Gas expanders may be employed where a gas exists at one pressure, and can be used or disposed of at a lower pressure. These units are found primarily in power recovery or in refrigeration processes where the cooling effect of expansion is required.

6. Combustion Gas Turbines

Combustion gas turbines are designed to be direct coupled or geared to their respective driven equipment. The range of available turbines for industrial use today is from approximately 180 - 50,000 KW for mechanical drives and up to 300,000 KW for generator drives. Two major configuration classifications, single and two shaft, allow a wide range of speed variation. The single shaft unit is limited to approximate usable speed variations of 10%. The two shaft design, however, effectively allows continuous operation between approximately 55 and 105% of rated speed.
Combustion gas turbines are relatively light weight drivers and have proven to be exceptionally reliable. They require, in general, little or no water and minimize the need for electrical power.

The energy source for the combustion gas turbine may be obtained through the use of gaseous or liquid fuels, and the unit generally can be configured to utilize both fuels. They are therefore most suitable for processes and/or locations where these fuels are readily available, such as pipeline transmission, gas treatment, gathering, storage and pressurization and other oil and gas related applications. They are well suited to power generation as well, when gaseous fuels are most accessible.

**COMBUSTION GAS TURBINE DESIGN CONSIDERATIONS**

Gas turbines have been designed with reliability, efficiency and safety as foremost considerations. The superior machines are the result of careful study of applications and other factors which influence the physical characteristics of the machinery, and in particular, its operatability in the application.

Applications for such machinery are found in nearly every natural environment in the world. They must stand up to the cold of the arctic, where ice storms and constant frigid temperatures are the norm. The same units must operate reliably and efficiently in the tropical climates — amidst high levels of ambient temperature, extreme humidity, torrential rains and other environmental hazards such as insect swarms. They must be capable of equal performance in the hot and dry desert climates of the world, where dust and sand storms pose potential hazards and a lack of cooling media may create special design needs.

Since the gas turbine is lighter and more compact than other equivalent drivers, its design must incorporate the needs of off-shore operation and a salt laden atmosphere which can accelerate corrosion of internal and external metal parts.

Another consideration in the design of a gas turbine is the variety of fuels that may be available. Certain applications may require operation on very low heat content fuel, such as sewage treatment waste gas, and other applications may provide fuels with very high heat content like propane. Yet another application will make available liquid fuels, and others, both liquid and gas. The capability of dual fuel is essential in turbine design to allow flexibility of application.

Another environmental consideration which must be taken into account is noise pollution. In remote areas, noise control is generally considered unimportant. But in other areas such as an off-shore platform where space is limited, or near populated cities or towns, it is vital to provide adequate noise insulation and control for the comfort and livelihood of the people that live near the installation. On the off-shore platform, these same people must operate and maintain the machinery.
The control systems of such machines are vital to the machine operation and the process of which they are a vital part. These systems must be reliable, easy to operate and easy to maintain. They must be capable of controlling a single machine or multiple units configured in series or parallel operation. A well engineered and designed control system must be capable of performing its function based on many different parameters, such as compressor or pump suction or discharge pressure, process flow, speed or temperatures.

Gas turbines, whose designers have considered the wide variety of applications and environments will be as self contained as possible, and will require minimum support utilities. In many remote areas there is no water or steam and little electrical power. Gas turbines are generally designed such that water is unnecessary and electricity needs are minimized. Good, self contained units will provide shaft driven oil pumps which would otherwise consume large amounts of power. A small emergency battery pack is all that is required to keep the unit in operation in the event of power loss, if configured in this way.

A final consideration in the design (and selection) of combustion gas turbines is foundation requirement. The rotary motion of these machines produces far less vibration than the back-and-forth motion of reciprocating machines. Generally, with the lighter aero derivative gas turbine a mere concrete pad is sufficient. For off-shore applications, the platform's own structural steel provides an adequate foundation for the aero derivative gas turbine.

**BASIC INDUSTRIAL GAS TURBINE TYPES**

Today, there are two basic combustion gas turbine types available each with several different configurations. For example: both are available in single shaft or two shaft design and both can be obtained with regeneration for higher efficiency. The two basic types, however, are quite different in design concept and physical characteristics. They are the heavy duty industrial type, and the aero derivative industrial type.

A comparison of these two types of gas turbines is essential when selecting a prime mover for industry. Major considerations range from fuel consumption to maintainability, and the priorities placed on each category must consider fuel availability and cost, geographic location, operator expertise, service availability, the critical nature of downtime and many other criterion.
1. Fuel Consumption

The aero derivative turbines are generally more efficient and thus require less fuel for equal output. They derive much of their high efficiency from their higher turbine inlet temperatures and higher compression ratios. The highest efficiency levels in the industry today are achieved with these machines. The heavy industrial type can attain approximately equal efficiency levels by adding regeneration. These increases in efficiency are attained by the regeneration raising the turbine inlet pressure and temperature, but a consequent loss in output power results. An increase in turbine size can restore this lost power, but at increases in other costs such as maintenance and service, and fuel costs as well.

2. Reliability and Availability

Reliability is the percentage of total operating time the machine is actually operated. It can be expressed as an equation:

\[
\text{Reliability} = \frac{\text{Hours Operated}}{\text{Hours operated} + \text{Unscheduled downtime}}
\]

Availability is the percentage of time the machine is operating or available for operation with respect to the total installed time. It is expressed in the equation:

\[
\text{Availability} = \frac{\text{Installed time} - \text{Total downtime}}{\text{Installed Time}}
\]

Decades of experience have proven that gas turbines generally rank high in terms of reliability and availability. Figures of 98% and higher are not unusual concerning reliability, and many gas turbines have registered impressive availability of 99.5% and beyond.

These figures of reliability and availability are significant in that downtime relates directly to lost product. It is useful to briefly study some of the design characteristics of one type of turbine in relation to another. This type of comparison can indicate expected reliability and availability.

3. Service/Maintenance

The majority of service to the aero derivative turbine is to the gas generator, not the power turbine. The gas generator, and/or associated modules can be completely removed and replaced in a few hours with a crew of no more than four. Heavy duty turbines require days and sometimes weeks to accomplish inspection and maintenance.
Generally, aero derivative turbines are provided with boroscope capabilities which permit visual access to any significant component within the machine. This feature allows detection of required maintenance with no requirement for disassembly. Potential problems are also detected in advance, and allow the service and maintenance personnel to prepare. Downtime can then be scheduled for times of minimum cost or inconvenience. The turbine requires maintenance on-condition, and not at regular prescribed intervals. The fixed time between overhauls is the general requirement of the heavy duty type, which then requires disassembly at more frequent intervals. The boroscope feature has been accepted by industry such that newer designs of the heavy duty type turbines generally incorporate this feature.

4. Installation

The compactness of aero derivative gas turbines will generally provide opportunities for significant installation savings. Physical size of units, inlet and exhaust requirements and certainly weight are considerably less. This results in savings of space and foundation structures which are direct cost areas. Additionally, transportation and support structure costs will be less.

HISTORY OF AERO DERIVATIVE GAS TURBINES

The evolution of the gas turbine over the past 35 years has been spectacular. From a laboratory concept at the end of World War II, this machinery has come to dominate aircraft propulsion and has seen broad applications in non-flying uses throughout the world. Vast sums of money and massive engineering development programs lie behind this machinery advance. The importance, of course, is more than the competitive pressures of an intensely competitive industry, but involves the fundamental security of nations through their air power. Furthermore, this art is far from reaching a technical plateau and substantial advances are yet to be made.

Because a running controversy exists among users and vendors of industrial gas turbines over the relative merits of heavy construction designs compared with aircraft derived machines, it is of interest to trace the development of each concept. In the beginning, the first practical gas turbines were conceived for fighter aircraft in the latter part of World War II. These engines offered a giant step forward in aircraft performance and consequently attracted massive government investments following the end of hostilities. At this time, development was channeled toward aircraft performance with little thought in mind that these machines might have other uses. In fact, the objective was to provide engines with maintenance requirements up to standards of piston type aircraft engines of approximately 1,000 hours of operation between removals for major rework.
While government funding was pouring into this endeavor, numerous machinery companies saw the benefits the gas turbine principle could bring to a variety of industrial applications. Private efforts were, therefore, undertaken to evolve such machinery with varying degrees of success. Because industrial applications did not face the difficult parameters of light weight and small frontal area essential to airplane engines, the industrial effort proceeded to design along the type of construction that was familiar from the older steam turbine technology. This resulted in reliable prime movers, which, with the passage of time, have been increased in size, versatility and breadth of application.

Meanwhile, the aircraft engine development, while concentrating first of all on weight, fuel consumption, frontal area, etc. also began to display durability beyond expectations. Instead of matching the durability of the piston aircraft engine, the gas turbines in aircraft use were soon operating on overhaul cycles many times that of the type they displaced. One engine for example, which entered airline service with a Federal Aviation Administration authorization for 1,000 hours between overhaul removal was within a few years authorized to operate for 11,000 hours according to FAA regulations. Other aircraft engines in use on airlines followed this pattern of extended service intervals.

Aircraft service is much more rigorous in a number of particulars than a normal industrial application. Operating time for an airplane engine is accumulated in short intervals of only one or two hours on the average between stops and starts. Aircraft engines are also subject to maximum firing temperature during take-off, with the attendant shortening of repair intervals. It therefore, became obvious by the late 1950's that an engine that could perform this well in flight had potential to operate reliably in industrial use. In the early 1960's a number of companies undertook trial installations of aircraft engines, primarily to drive centrifugal compressors in gas pipeline service. Like all new machinery applications, a variety of problems were encountered and changes were required. None of these, however, disproved the concept that the aircraft engine could satisfy industrial needs, and over the past two decades the share of industrial applications turning to the aircraft derived engine has steadily increased.

Today, aircraft derived engines are in broad usage around the world, and interestingly enough are becoming favored for the most rigorous and remote projects. Projects such as the Alaska Pipelines, Siberian Pipelines, desert and off-shore platform type projects find the aircraft derived engine provides significant advantages over the heavy weight earlier industrial type designs.

A primary advantage of the aircraft derived industrial turbine is the higher on-line availability it offers the user, as described previously.
Considering the history of the aero derivative turbine cited in prior pages, government funding has allowed nearly limitless development capital to perfect weight, size, efficiency and in particular, reliability. This technology will always be ahead of the industrial technology. No industrial company could afford to fund such development on their own, nor could they access the development assets of people, testing facilities and laboratories available to governments.
The following is an example of a typical economic evaluation of an aero derivative vs. heavy duty type of industrial turbine.

Capital costs, such as equipment and its installation are considered single future amounts. Fuel and maintenance costs are examples of single future amounts for the given year, since inflation is taken into account. The method of the evaluation is Discounted Present Worth, where future expenditures are converted to present costs. This procedure utilizes an assumed value for the cost of money.

While a complete present worth documentation would include all items of cost for each alternate under consideration, the same results can be obtained by working with differential costs only. By eliminating costs that are judged to be equal for all machines and working with cost differentials only, the mechanics of tabulating the essential data is appreciably reduced. This is the procedure followed, with the exception of unit price. This item could also be handled on a differential basis, but it is more common to include it at full value.

1. Equipment Compared
   A. Aero derivative (5,000 ISO HP)
   B. Heavy duty (5,000 ISO HP)

2. Operating Conditions
   a) Site elevation - sea level
   b) Design ambient - 95°F
   c) Horsepower required per unit - 3,600 HP at site
   d) Four (4) units installed 1985
   e) Operating speed - 100% of design
   f) Operating time - 330 days/yr (7,920 hrs/yr)

3. Assumptions for Evaluation
   a) Project life - 15 years
   b) Cost of money - 10% per year
   c) Cost of fuel - $4.00/MMBTU
   d) Inflation - 5% per year
4. Economic Evaluation

a) Capital cost for 1985 shipment

1. Aero derivative - $6,000,000
2. Heavy duty - $5,000,000

b) Thermal efficiency and heat rate of turbines at site

1. Aero - at 3,600 horsepower (site requirement)
   9,800 BTU/HP·HR
2. Heavy - at 3,600 horsepower (site requirement)
   10,400 BTU/HP·HR

c) Calculate and tabulate annual fuel cost

1. Aero \( FC_1 = 9,800 \times 3,600 \times 7,920 = 279,418 \) MMBTU/yr
2. Heavy \( FC_2 = 10,400 \times 3,600 \times 7,920 = 296,525 \) MMBTU/yr

Fuel cost differential = \( 296,525 - 279,418 = 17,107 \) MMBTU/yr
Actual differential cost = \( 17,107 \times 4 = 68,428/yr \)
Since four (4) units are running, total fuel cost differential is $273,712/yr.

As can be seen from the tabulation of present worth, costs associated with installation and fuel are higher for the heavy duty units, and the differential is represented in the tabulation. This differential is significant. Over the 15 year life of this project, the evaluation is $1,904,695 in favor of the aero derivative type of machine, even though the initial capital cost is considerably higher.
### Table 1: Present Worth of Heavy Duty Industrial

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<tr>
<th>Year</th>
<th>(1) Present Worth Factor</th>
<th>(2) Capital Cost of Machine</th>
<th>(3) Difference in Installation Cost</th>
<th>(4) Difference in Fuel Cost</th>
<th>(5) Difference in Maintenance Cost</th>
<th>(6) (2+3+4+5) Total Cost in Year Considered</th>
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* Add differences in cost to present worth of machine which has higher cost considered

**Total** 7,900,604

### Table 2: Present Worth of Aero Derivative Industrial

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<th>Year</th>
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**Total** 6,000,000

478
I. Introduction

The concept of turboexpanders dates back to 1900 when George Claude of France applied a small engine to an Air Separation Plant. About 40 years ago Dr. Swearingen, President of our Company, built and operated the first Natural Gas Cryogenic Expansion Turbine in the United States.

By the 1950's turboexpanders were standard equipment in Oxygen, Nitrogen Plants and widely used for Helium and Hydrogen purification.

In early 1960 the first commercial Natural Gas Cryogenic Turboexpander Plant started operation in Southwest Texas.

Today the turboexpanders are proven, reliable, and used widely in the following Natural Gas applications:

- Ethane and Propane Extraction
- Natural Gas (NG) Dewpoint Control
- Production of Liquefied Natural Gas (LNG)
- Flashing Hydrocarbon Liquids
- NG Pressure Letdown Energy Recovery
- Oilfield Cogeneration

Before discussing these applications, I would like to first show what
a turboexpander looks like and the various loading devices available.
We will also show a few of the many design features that have contributed
to the Expanders high reliability and efficiency, their ability to
operate uninterrupted for years with very low maintenance.

II. Turboexpander Description
An NG Turboexpander is used mostly to produce low temperature refrigeration.
The refrigeration produced is the mechanical equivalent of power (2545 Btu/
Hr per HP) and is derived from the expansion energy of the pressurized gas.

The amount of refrigeration or power depends on the amount of gas and the
expansion pressure ratio (Head) (a reasonable ratio is four to one). In
a natural gas process the refrigeration is of primary importance and the
power, although valuable, is secondary. However, the power developed must
be absorbed and the most frequent device is a direct driven compressor.

A typical turboexpander compressor for NG process is shown in Fig. 1.
A cross section of such a unit is shown in Fig. 2. The expander is at
the left and compressor at the right. The wheels are overhung on each
end of the shaft which is supported by bearings immediately behind the
labyrinth shaft seals.

An important feature of this design arrangement is that all the moving
parts are mounted in this Mechanical Center Section (MCS) which provides
for an inexpensive backup or spare which can be installed to replace the
operating MCS in case of problems or for maintenance.

From this cross-sectional view we can also see the provision made for
seal gas or buffer gas needed to separate the low temperature feed gas in the expander casing from the bearing housing.

III. Turboexpander Applications
Since 1963 when the cryogenic natural gas process was first introduced, close to 1,000 units are presently in operation including several on offshore platforms.

This diagram (Fig. 3) shows a simplified flow scheme of such a process. Gas is dried to a dew point compatible with the low temperature of the product stripper and then processed through the expander. The power is used to partially recompress the lean residue gas.

Several modifications of this basic scheme have been used including multi-stage arrangement, all depending on the feed gas composition, the desired recovery (of LNG or LPG) or the seal gas specification.

If the process plant is located at or near the field and the gas needs to be sent via pipeline to an optimum location for final treatment or liquefaction, the objective is to avoid condensate forming on the pipeline. A similar simpler process is then used to provide the required water and hydrocarbon dew point.

A turboexpander system for this purpose can be designed such that the liquid condensed in the expander and separated gives the residue gas the proper dew point and the expander driven compressor will deliver the desired pipeline pressure, thus eliminating the sales gas compressor shown in the diagram shown earlier.
Our Firm delivered twelve 6,000 HP Expander Compressors to Sonatrack for their Hassi "R" Mel Field in Algeria utilizing such a process.

Other options for treatment of gas, be it for dew point control or to provide specified heating value of sales gas or for NGL recovery, are available such as Joule Thompson Expansion, External Refrigeration, Absorption Process, and the above mentioned Expander process.

As an initial guideline to select the process, the following is quoted from the "Natural Gas Processors Suppliers Association" Engineering Handbook (Ref. 1).

"Selection of a turboexpander process cycle is enhanced when one or more of the following conditions exist:
1) Availability of "free" pressure drop in the gas stream.
2) Lean gas.
3) High ethane recovery requirements (i.e., over 30% ethane recovery).
4) Compact plant layout requirement.
5) High utility costs.
6) Flexibility of operation (i.e., easy adaptation for wide variation in pressure and products).

There are multiple factors in addition to the ones listed above that affect a final process selection. If two or more of the above conditions are coexistent, generally a turboexpander process selection will be the best choice."

Studies made prior to selecting a process for treatment of rich associated gas from Occidental's Piper Field in the UK Sector of the North Sea (Ref. 2) showed that about 28% and 22% more condensate is produced for
the external refrigeration and the turboexpander options, respectively, than for the J-T case. This is due to the greater cooling provided in these cases compared to the J-T case. As condensate has a higher value than gas when exported from the platform, Cases 2 and 3 will provide higher revenue than Case 1. Further, the energy consumed for Case 3 is lower than either Case 1 or Case 2, a factor in favor of the turboexpander system. Besides the direct process considerations of greater condensate and lower utility needs, the turboexpander process has the least equipment count. For an offshore platform this has a definite advantage for space requirements and reduction in complexity. Detailed estimation of weight of the equipment associated with the turboexpander indicates that this system is lighter than the external refrigeration scheme. The use of an expander also has other advantages. For example, in the range of 4 million to 20 million KJ/hr of refrigeration, an expander system costs from one-half to one-third that of an equivalent refrigeration system. This is in addition to the advantage of producing power instead of consuming it. As indicated previously for offshore application, weight and space is of vital importance. An expander process has the further advantage of using one-third the floor area and weighing only one-quarter the weight of an equivalent refrigeration plant. Our Firm has delivered 10 Expander Compressors for operation on offshore platforms.

Since many of the natural gas fields are some distance from the market area, extensive pipeline systems are installed to transport the gas. During heavy demand periods in the winter, the need for a peak-shaving supply of gas becomes mandatory. Turboexpander processes have been used in many such peak-shaving plants. A proposed scheme is shown in Fig. 4 (Ref. 3).
Base load LNG plants could well utilize the expander process especially if a large LNG plant is on an offshore platform or on a barge as has been proposed.

The space and power savings of the expander process would benefit in such plants also. Recovering energy from high-pressure liquids is a well-established energy-saving scheme using standard pumps rotating in reverse. However, if the liquid flashes as the pressure drops, a turboexpander can offer economic advantages in producing energy and refrigeration. In 1972 such 350 HP Expander Compressor for cold flashing liquids was installed in a Natural Gas Treatment Plant in Texas (Ref. 4). This turboexpander recovers most of the power from the liquid-pressure reduction and also a large amount of power from the accompanying expansion of the gas and vapor. (Fig. 5).

Another such flashing liquid expander was installed for Norsk Hydro expanding Liquid Nitrogen of close to 2000 psi. In this system the expander power was absorbed by a generator through a speed-reducing gear. So far we have been looking at turboexpander processes where the refrigeration obtained from the expansion has been the prime factor and power secondary.

However, with the current efforts to find alternate sources of energy and to build more energy-conserving plants, we find turboexpanders playing a new and important role. As mentioned above, most of our natural gas is transported in pipeline systems to the various market areas. Such
pipelines operate at approximately 600 psi and are reduced for distribution within populated areas.

San Diego Gas and Electric placed in operation a pressure letdown turbo-expander generator unit at their pressure-reducing station north of San Diego, California (Fig. 6). This expander generator now handles the base flow of gas which previously was passed though reducing valves and thus recovers approximately 300 kw from the pressure letdown. Since the U. S. Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978 which encourages the production of electricity from renewable resources and from cogeneration, many such installations are being planned.

This law requires that utilities must buy electricity from such small electric producers at a cost equal to what it would have cost them to generate the power themselves. Six months ago Rotoflow delivered a large 4000 kw Expander Generator for Chevron USA’s Oil Fields near Bakersfield, California (Fig. 7). This "topping turbine" reduces steam pressure from 1600 psi to the field injection pressure of 600 psi. Chevron expects this installation will be paid off in a few years through electricity and fuel savings.

Turboexpander Qualities and Features

From the preceding applications it is apparent that a turboexpander is a special turbine which should be designed with quality features to meet the following requirements:

- Maintain high efficiency with varying flow
- Toleration of dust or condensation of gas stream
- Bearing strength to avoid damage if the rotor should be unbalanced by ice deposits, or damaged by erosion
- High efficiency (usually requiring high speed)
- Proven reliability
- Positive shaft seals or other special seals
- Wide range of sizes

V. Variable Flow Control

A high quality turboexpander has variable flow control nozzles capable of withstanding the total pressure and acting as the flow control for the main gas stream through the plant. The variable nozzle should be matched with a rotor to give high efficiency over a wide range of flows (usually from 50% to 120% of design or wider) (Ref. 5, Ref. 6, Fig. 8). They should be designed for negligible blow-by and for durable performance, even if constantly moved as by a pressure-controller or other controlling signal (Fig. 9).

VI. Expansion of Condensing Streams

As to the utilization of turboexpanders for condensing streams, this is solved by a very interesting development in which the blades in the expander rotor are so shaped that their walls are at every point parallel to the vector resultant of the forces acting upon suspended fog droplets (or dust particles) (Ref. 7, Ref. 8, Fig. 10). Then the suspended fog particles do not drift toward the walls, collect and interfere with performance and erode the blades. Over 100 turboexpanders are in successful operation involving condensing liquids.

VII. Dust

Dust-laden streams can also cause operational problems. A turboexpander that can efficiently process condensing streams (gas with fog droplets suspended) can usually handle a stream with suspended solid particles, as long as the particle size, if they are highly erosive, does not exceed
2 to 3 microns. A new design has been developed for reducing erosion of an expander back rotor seal by disposing of the dust that accumulates at the seal and discharging it through the balancing holes in the expander rotor (Fig. 11, Ref. 7). We believe large expanders can be designed to handle dust or particles up to 10 microns.

VIII. Thrust Bearing Force Meters (Fig. 12)

Machines with an expander inlet pressure of the order of 10 Bars carry thrust loads usually within the capabilities of the thrust bearings. At higher pressures, it is essential to carefully balance the thrust loads against each other. Thrust loads, even though originally correctly balanced, may change greatly and exceed the thrust-bearing load-carrying capacity. This imbalance of thrust loads may be caused by either erosion of a seal, icing or off-design operating conditions. This problem has been solved by a force-measuring meter on each thrust bearing, and in some cases, a thrust control valve which controls the thrust by control of pressure behind the thrust-balancing drum (Ref. 10).

Because of features such as these, the reliability of turboexpanders is exceptionally good. Operation for several years without repair is most common.

Turboexpander sizes range from a few horsepower up to 15,000 HP with proven operating record. Inlet pressures up to 3,000 psi is standard. The temperatures range from 400°F. down to close to absolute zero.

IX. Conclusion

Turboexpander natural gas applications have evolved as a result of available turboexpanders with the required high-performance capabilities
and reliability; and conversely, the development of these processes has pointed the way toward further improvements in turboexpanders.

In summary, the state of the art of modern turboexpanders has reached a very high level of reliability and efficiency.

Mechanical designs of low temperature, high speed machinery are routine.

Stiff shaft designs have eliminated shaft and bearing criticals in the entire operating range.

Rotor resonance problems are well known to the designers and are, in most cases, totally eliminated.

Thrust bearing problems (the weakest area in high speed machinery) can be accurately monitored and controlled.

Condensing streams and some dust in gas can be handled without erosion.

These are the most important features that make the use of turboexpanders ideal for natural gas processing and recovery of power from the vast resources of pressurized gas streams.
FIGURE 1
N.G. TURBOEXPANDER COMPRESSOR

FIGURE 2
EXPANDER COMPRESSOR CROSS-SECTION
FIGURE 3.
EXPANDER COMPRESSOR
NATURAL GAS PROCESS
FLOW SCHEME
FIGURE 4.
L.N.G. EXPANDER PROCESS

FIGURE 5.
PRESSURE/VOLUME EXPANSION
FIGURE 6.
EXPANDER GENERATOR UNIT FOR SDG&E
FIGURE 7.
STEAM EXPANDER GENERATOR FOR COGENERATION
FIGURE 9.
VARIABLE INLET GUIDE VANES

FIGURE 10.
CONDENSING EXPANDER ROTOR
FIGURE 11.
ROTOFLOW'S DUST-FREE DESIGN

FIGURE 12.
ROTOFLOW'S THRUST METER SYSTEM
References


METHODS AND ECONOMICS FOR SEPARATING CARBON DIOXIDE FROM VARIOUS GAS STREAMS

By

Roland E. Meissner, III
Kenneth G. Braden
H. Robert Scivally

The Ralph M. Parsons Company
Pasadena, California
U.S.A.

Prepared for Presentation at

Thailand - United States of America
Natural Gas Utilization Symposium
Bangkok, Thailand

February 7 to 11, 1984

Abstract

The removal of carbon dioxide from natural gas is desirable before the gas is used as a feedstock for petrochemical production. For production of hydrogen and ammonia within a petrochemical or fertilizer complex, CO₂ removal is necessary. This paper discusses processes and comparative economics for separation of CO₂ from natural gas, hydrogen, and ammonia synthesis gas. Processes include those which use physical and chemical solvents. The BASF Activated MDEA process is introduced as a low capital and low energy alternative which is applicable to all three separations.
INTRODUCTION
For the past thirty years, The Ralph M. Parsons Company has been involved in
design and construction of high pressure natural gas plants in Canada, the North
Sea, Middle East, and North Slope of Alaska. For example, from the mid-1950's
to mid-1970's Parsons designed and built a substantial percentage of high
pressure sour gas processing plants operating in Western Canada today. These
plants process approximately 2.25 billion standard cubic feet per day (SCFD)
of natural gas, recover about 100,000 barrels per day (BPD) of liquids, and
produce 13,200 long tons per day (LTD) of sulfur. Interestingly, the majority
of these plants use the Societe Nationale (Elf) Aquitaine (SNEA) high load
diethanolamine (DEA) process for removal of acid gas constituents from sour
natural gas.

The Petroleum Authority of Thailand (PTT) is planning a large petrochemical
and fertilizer complex which will convert well fluid feedstock from offshore
to salable products including natural gas, gasoline, ammonia, hydrogen, ethy­
lene and various polymers derived from ethylene. As shown in Figure 1, a
common denominator in the production of natural gas, ammonia and hydrogen is
the requirement to remove $\text{CO}_2$ from a gas stream. For natural gas and hydrogen,$\text{CO}_2$ is removed to purify the product. For ammonia production, $\text{CO}_2$ is removed
from the synthesis gas stream prior to reaction. The recovered $\text{CO}_2$ can be used
to produce urea by reaction with ammonia at high pressure and to produce soda
ash.

PROCESSES AVAILABLE
As shown in Table I, processes for removal of $\text{CO}_2$ from natural gas, ammonia
synthesis gas, and hydrogen include not only the alkanolamine processes such
as monoethanolamine (MEA), diethanolamine (DEA), activated hot potassium
carbonate such as Benfield, Catacarb, or Flexsorb HP but also physical solvent
processes such as Selexol, Sepasolv MPE, Rectisol and Purisol. A key advantage
of physical solvent processes over alkanolamine or hot carbonate processes is
that the solution can be regenerated by flashing rather than by steam stripping
used in conventional alkanolamine and hot carbonate processes. Regeneration by
flashing results in large energy savings.
A decided disadvantage of physical solvent processes is that they absorb hydrocarbons present in hydrocarbon wet natural gas. These hydrocarbons are absorbed by the circulating physical solvent and expelled with the CO₂ in the flashing and stripping operations. In the cases of hydrogen purification and removal of CO₂ from ammonia synthesis gas, hydrogen is also coabsorbed with CO₂. With a physical solvent process, costly recycle of the flash gas to the absorber feed is required to increase hydrocarbon or hydrogen recovery in the treated gas. This recycle requires compression and increases the required capacity of the plant.

Hydrocarbons expelled with CO₂ can represent losses of salable hydrocarbon liquid (LPG) unless the CO₂ and hydrocarbons can be burned in the plant to recover fuel value of the hydrocarbons. The plant fuel system is more complicated if a low BTU hydrocarbon stream containing CO₂ must be burned. Hydrogen expelled with CO₂ represents loss of valuable hydrogen product.

For handling CO₂ bearing natural gas, hydrogen or ammonia synthesis gas, an ideal solvent would be one which has the hydrocarbon or hydrogen solubility properties of an aqueous alkanolamine or hot carbonate process, yet has a low energy requirement characteristic of a physical solvent process.

For the purification of hydrogen there exists a widely used process for removing CO₂ and other contaminants known as Pressure Swing Adsorption (PSA). This process uses molecular sieves as an adsorbent rather than a solvent to adsorb CO₂ from the hydrogen stream. Hydrogen purity of 99.999 percent can be achieved with PSA rather than the conventional 97 percent purity that can be achieved with a solvent. Regeneration of the molecular sieves is accomplished by pressure reduction.

**PROCESS SELECTION**

The selection of the most cost-effective process for removing CO₂ from natural gas, ammonia synthesis gas or hydrogen depends mainly on the gas treating pressure, gas composition, and treated gas specifications. To simplify the
gas treating, the same solvent should be used for treating the various gas streams in the PTT petrochemical and fertilizer complex. Using the same solvent minimizes storage requirements, permits use of a common solvent regeneration facility and minimizes the amount of operator training required. The choice of the most suitable gas treating process depends on several other criteria (Table II):

COMMERCIAL EXPERIENCE
Process selection should be based on past experience in similar gas treating services.

ENERGY REQUIREMENTS
Suitability of a particular gas treating process depends on the energy required to remove CO$_2$. The more energy used by the process the less natural gas will be exported by the complex.

TREATED GAS SPECIFICATION
The capability of a particular process to produce a treated gas which meets specification is of prime importance in selection of a suitable process.

BY-PRODUCT FORMATION
The solvent should not react with contaminants present in the feed gas, forming undesirable by-products which degrade the solvent. Degraded solvent must be replaced which increases operating costs. In processes using hot potassium carbonate, formic acid may be formed from CO present in the gas. Non-regenerable potassium formate may be generated which must be purged from the system.

CAPITAL COST
In any gas treating process selection, prime consideration must be given to capital cost of the constructed plant. Provided the gas treating process will perform as required, the process with minimum capital cost is desired.
OPERATING COST
Cost of utility and chemicals consumed must be minimal for the process selected.

ACID GAS COMPOSITION
Processes which minimize the solubility of hydrocarbon or hydrogen are desirable since loss of valuable product with CO₂ is minimized.

CORROSION
The gas treating process should not use a solvent which is extremely corrosive or forms by-products which are extremely corrosive for commonly used industrial metallurgy.

BASF ACTIVATED MDEA PROCESS
Late in 1981, Parsons began discussions with BASF Aktiengesellschaft concerning its long-used Activated Methyldiethanolamine (MDEA) process. The process has been used to remove CO₂ from synthesis gas. After further investigation, Parsons learned that BASF had a long and very satisfactory experience with the process in its Ludwigshafen plants and elsewhere. Since the solution is aqueous, hydrocarbon absorption is minimal. This process requires less capital and far less energy than others. The key to these savings is that the solution is regenerated by flashing rather than by the more conventional steam stripping.

The BASF Activated MDEA technology was developed in a series of steps which started with the use of pure water for removing CO₂ from ammonia synthesis gas. In an ammonia synthesis plant, removal of CO₂ represents at least 10 percent of the capital and operating costs. In addition there is a high solubility of hydrogen under pressure in water. This results in a large loss of hydrogen. Further process developments for CO₂ removal were necessary to reduce capital and operating costs as well as hydrogen losses.

One step in the series was the development of the BASF TEA wash process which uses the tertiary amine, Triethanolamine (TEA). This process, which first started up in 1966 and is still operating today, treats 62.4 MMSCFD of synthesis
gas produced by the partial oxidation of heavy oil. In the process the TEA aqueous solution was regenerated by flashing. This process has been commercialized in several installations. BASF then discovered that the tertiary amine, MDEA, with an activator to absorb \( \text{CO}_2 \) was much better than TEA. Solubility of \( \text{CO}_2 \) in the activated MDEA is twice that for TEA, and the mass transfer of \( \text{CO}_2 \) with activated MDEA is higher. In 1971 the first BASF Activated MDEA process started up and operated satisfactorily.

The BASF Activated MDEA technology is a cost-effective method for removing \( \text{CO}_2 \) from high pressure natural gas, particularly when the natural gas is hydrocarbon wet. Although the BASF Activated MDEA process is applicable for removing both \( \text{H}_2\text{S} \) and \( \text{CO}_2 \) from a high pressure gas stream, this discussion will concentrate on removal of \( \text{CO}_2 \) only.

**SOLUTION ISOTHERMS**

Figure 2 shows the solution isotherms for the solubility of \( \text{CO}_2 \) as a function of \( \text{CO}_2 \) partial pressure in 50 weight percent MDEA solution (about 4.5 molar). Also shown for comparison purposes are the solubility of \( \text{CO}_2 \) in the BASF Sepasolv MPE solution, a physical solvent, and in a 25 weight percent monoethanolamine (MEA) solution (about 4.1 molar).

The solubility of \( \text{CO}_2 \) in the physical solvent increases linearly with \( \text{CO}_2 \) partial pressure. Thus, the solvent circulation is almost independent of \( \text{CO}_2 \) partial pressure. It is determined mainly by total pressure and quantity of gas to be purified.

In gas treating processes, it is possible to use a single-stage \( \text{CO}_2 \) absorption in which the semi-lean solution used is produced by flashing the rich solution. This can be followed by a second stage of \( \text{CO}_2 \) absorption in which a portion of the semi-lean solution is well-stripped, with heat input, and used to remove the residual \( \text{CO}_2 \) from the gas.

In the case of the physical solvent, the second-stage absorption will require about the same solvent circulation as the single-stage absorption so that the
advantage of the second-stage absorption is minimal. By contrast, the curvature of the solution isotherm which is characteristic of the chemical solvent MDEA gives an economic advantage when two absorption stages are used.

For example, starting with a typical CO$_2$ partial pressure of about 5 bars, the thermodynamically feasible difference in CO$_2$ loading of the MDEA solution can be used in the first stage for the bulk removal of the majority of the CO$_2$ from the gas without any significant use of stripping steam. According to the figure, $\Delta X$ is equal to 30 M$^3$/M$^3$ of CO$_2$ per M$^3$ of solution. (This is the difference between 58 M$^3$/M$^3$ at 5 bar and 28 M$^3$/M$^3$ at 1 bar.)

Further purification, producing a treated gas containing less than 100 ppmv CO$_2$ can be achieved in a second absorption stage with the same MDEA solution but with a substantially smaller solvent circulation. Only the smaller second-stage solvent circulation must be thermally regenerated.

Also shown in Figure 2 is the CO$_2$ solution isotherm of a 4.1 molar MEA solution. This isotherm rises very sharply to almost the saturation level. This sharp rise causes a relatively small difference of about 11 M$^3$/M$^3$ in the CO$_2$-loading between CO$_2$ partial pressures of 5 bar and 1 bar so that a bulk removal of CO$_2$ by an adiabatic flash loop is uneconomical. Accordingly the MEA process is usually performed in a single stage with the entire solution being regenerated by heat.

From a chemical reaction viewpoint (Table III), the MDEA solution contains a tertiary bonded nitrogen atom as the active basic group. With MDEA solution, carbon dioxide is absorbed merely by formation of metastable bicarbonate, so that thermal regeneration with relatively small heat input is possible. For MEA and other primary and secondary alkanolamines, the reaction of CO$_2$ with the solution is reversible at higher temperatures. Chemical bonding of carbon dioxide with the primary nitrogen atom of MEA takes place partly with the formation of carbonate which is relatively stable and requires a higher heat input to generate.
As shown by the solution isotherms in Figure 3, solubility of CO$_2$ in MDEA is about twice its solubility in TEA. Furthermore, the shape of the MDEA isotherm shows that MDEA is a more suitable solution for regeneration by flashing. A greater difference in solution loading can be achieved with MDEA at comparable differences in CO$_2$ partial pressure. The higher CO$_2$ solubility and higher difference in solution loading results in lower circulation. Thus MDEA has an inherent economic advantage over TEA.

TEA PROCESS

As previously mentioned, in 1966, the first TEA wash plant operation commenced in Ludwigshafen, West Germany. The plant removed CO$_2$ from a raw synthesis gas at a pressure of about 70 bars. The raw gas composition is shown in Table IV. Figure 4 shows the process scheme used.

The raw synthesis gas enters the absorber where it is countercurrently contacted with TEA solution. The rich solution from the bottom of the absorber is fed to a hydraulic turbine where the pressure of the solution is reduced. Fluid energy is thus converted to mechanical energy which supplements the power required for the main circulation pump. The rich amine solution is then flashed in the first flash drum, where CO$_2$ and other minor constituents are expelled from the solution.

The semi-rich solution is then fed to the second hydraulic turbine for further pressure reduction and energy recovery. Semi-rich solution from the second hydraulic turbine is fed to the second flash drum where most of the remaining CO$_2$ is expelled from the solution. The semi-lean solution is recycled to the absorber, thus completing the circulation loop.

In this scheme the CO$_2$ content of the raw gas is reduced from about 34 volume percent to about 2.6 volume percent. The treated gas from this process is fed to a downstream Alkazid process where residual CO$_2$ is removed. The only heat input into the process for this application is a small quantity of stripper overhead from the Alkazid process (not shown on process flow diagram). The Alkazid stripper overhead contains about 5,300 pounds per hour of low pressure steam and an equivalent amount of CO$_2$. 
Thus with minimal energy input, the bulk of the CO₂ is removed from the synthesis gas. This process is still operating today.

APPLICATION TO AMMONIA SYNTHESIS GAS

In 1971, the first Activated MDEA plant operation commenced at BASF. The plant removed CO₂ from a raw ammonia synthesis gas at a pressure of about 28 bars. The raw gas composition is shown in Table V. Figure 5 is a schematic process flow diagram of the BASF Activated MDEA two-stage absorption process.

Raw ammonia synthesis gas enters the absorber where it is countercurrently contacted with activated MDEA solution. To minimize process energy requirements and to take advantage of MDEA's ability to be partially regenerated by a simple pressure reduction, the process employs two stages of CO₂ absorption.

The bulk of the CO₂ is removed in the lower section of the absorber with semi-lean MDEA solution. The remaining CO₂ is removed in the top section of the absorber with steam-stripped solution.

Rich MDEA Solution Regeneration

Rich solution from the absorber is reduced in pressure by letdown in two successive flash stages similar to those used in the single-stage TEA absorption process. It first flows through a power recovery turbine and then to the first rich solution flash drum. The mechanical energy recovered by the turbine is used to drive the semi-lean circulation pumps. Flash gas liberated from the rich solution in the first flash drum contains most of the H₂ and N₂ which were absorbed from the raw synthesis gas feed. In high pressure natural gas applications, a small amount of absorbed hydrocarbons will be expelled in the high pressure rich solution flash drum.

Flashed solution from the first stage is again flashed at low pressure in the second and final flash drum. The two stages of rich solution pressure reduction liberate most of the CO₂.
Lean MDEA Solution Regeneration

The regenerator provides required lean solution by stripping a portion of the total semi-lean solution from the low pressure flash drum. Semi-lean solution to the regenerator is heat exchanged against the hot lean solution from the regenerator. Vapors from the stripping section of the MDEA regenerator are used to strip and heat the semi-lean solution in the low pressure flash drum. Vapors leaving the low pressure flash drum enter the bottom section of the MDEA regenerator where most of the water contained in the gas is condensed.

The lean solution is pumped to the top of the absorber to complete the circulation loop. The treated gas from this process contains less than 50 ppmv CO₂.

Capital and Operating Cost Comparison

A comparison of the capital and operating costs of the BASF Activated MDEA process to the Benfield process shows that for processing the synthesis gas feed stream in Table V using a two-stage process, the capital cost for the two processes are about the same. However, there is a twenty percent savings in heat for solution regeneration with the BASF Activated MDEA process. Capital and operating costs would favor the Activated MDEA process at a higher feed gas pressure than 28 bars since more solution could be regenerated by flashing than by steam stripping.

APPLICATION TO NATURAL GAS

In South Texas, U.S.A., an existing DEA unit was converted to the single-stage Activated MDEA process. The rich DEA flash drum became the high pressure flash drum; the stripper became the low pressure flash drum. No other major modifications were made to the plant other than installing bypasses around the lean/rich exchanger and lean solution cooler.

As shown in Table VI, prior to conversion, the plant processed 9 MMSCFD of natural gas at about 950 PSIG. The gas contained 8 percent CO₂ and 50 ppmv H₂S. Required treated gas specifications were 3 percent or less CO₂ and 1 grain/100 SCF H₂S. Approximately 10 MMBTU/HR of heat were required.
After conversion, the treated gas specifications were easily met. The plant still processed 9 MMSCFD. Energy input was reduced to zero. Solution Circulation remained the same. All solution regeneration was accomplished by flashing rather than stripping.

APPLICATION TO HYDROGEN PURIFICATION

The two-stage BASF Activated MDEA process for purifying hydrogen is similar to the one discussed for purifying ammonia synthesis gas. Savings in heat utilization cannot be as advantageous as in ammonia plants since there is excess low level heat available in hydrogen plants.

With a PSA process, about 15 percent of the hydrogen is coadsorbed with the CO₂ and utilized in the fuel system when the molecular sieves are regenerated. To produce a specified quantity of hydrogen requires excess hydrogen in the feed to the PSA process. This means that additional natural gas feed to the hydrogen plant is required.

No excess feed is required for aqueous solvents such as alkanolamines since coabsorption of hydrogen with CO₂ is minimal.

In general, when the natural gas feed to the hydrogen plant has about the same value as fuel gas, the PSA process is a standoff or more cost-effective than an aqueous solvent process for removing CO₂ from hydrogen. When natural gas feed is worth more than fuel, an aqueous solvent such as Activated MDEA is more cost-effective.

SALIENT FEATURES

There are a number of salient features which make the single-stage and two-stage Activated MDEA process most suitable for economically treating high pressure gas.

COMMERCIAL EXPERIENCE

Since 1966 BASF has acquired a great deal of commercial experience with the BASF tertiary amine processes. The installed capacity of the two-stage BASF Activated MDEA process is about 750 MMSCFD at BASF installations throughout
the world. The two-stage process was selected for the Northwest Pipeline project to remove CO₂ from 2.2 billion SCFD of natural gas at the North Slope of Alaska.

ENERGY REQUIREMENTS
The single-stage process does not require costly solution regeneration equipment required for chemical solvent processes. Steam stripping of the solution is not required. Thus capital costs for the process are lower. Energy requirements are limited to supplementary power required to drive the main circulation pump. The solution has a high concentration of MDEA and high solution loadings of CO₂ are achieved. Both reduce circulation.

For the two-stage process only a portion of the semi-lean solution is regenerated which reduces capital cost and energy requirements. The average amount of process heat required is only about 18,300 BTU per lb-mole of CO₂ removed. Energy consumption for this process can be as low as 10 to 20 percent of that required for other comparable chemical solvent processes.

METALLURGY
Metallurgy requirements for the BASF Activated MDEA process are based on 11 years of operating experience. The solution is not corrosive to carbon steel; thus, the majority of the plant is constructed of carbon steel. Since the MDEA does not degrade, corrosion by degradation products is not a problem.

HYDROCARBON AND HYDROGEN SOLUBILITY
Since an aqueous solution is used, hydrocarbon and hydrogen solubility in the circulating solution is minimized. Thus losses of hydrocarbons or hydrogen with CO₂ are minimal.

SOLUTION LOSSES
For the TEA process during 17 years of operation in West Germany, solution loss has been minimal. In the 11 years of operation of the BASF Activated MDEA process in West Germany, solution makeup per year has been about 15 metric tons per year. Total solution inventory is 160 metric tons so that
in 11 years of operation, the solution inventory has barely been turned over once. In the existing TEA and Activated MDEA processes there has been no solution degradation nor solution filtering nor solution reclaiming is required. The solutions are stable and not subject to degradation.

PLOT AREA
For the single-stage process, plot area requirements for the process are minimal due to the few pieces of equipment. A plant processing 50 to 100 MMSCFD of gas will require a plot area approximately 45 feet by 45 feet. The two hydraulic turbines and main circulation pumps are mounted on the same shaft with the pump motor, which also helps to conserve space.

Plot area requirements for the two-stage process are slightly larger than for the single-stage process, depending on the size of the regenerator and ancillary equipment.

RELIABILITY
In 17 years of commercial operations, the process has proven to be highly reliable in achieving treated gas purity with minimal operator attention and maintenance.

CONCLUSION
There exists a low energy process for treating high pressure gas containing CO₂. Capital investment for this process is less than other chemical solvent processes while energy requirements can be as low as 20 percent of other chemical solvent processes.
BIBLIOGRAPHY


Volkamer et al, "New Developments in the Purification of Synthesis Gas", 2nd World Congress of Chemical Engineering and World Chemical Exposition, October 4 to 9, 1981.
FIGURE 2
CO\textsubscript{2} SOLUTION ISOTHERMS IN MEA, MDEA, AND SEPA\textsubscript{SOLV} MPE (0\degree C)

CO\textsubscript{2} PARTIAL PRESSURE (BAR)

CO\textsubscript{2} LOADING
\[ \frac{\text{M}^3\text{ GAS}}{\text{M}^3\text{ SOLV}} \]

\[ \Delta X \]

MEA 4.1 MOLAR, 60\degree C
MDEA 4.5 MOLAR, 70\degree C
FIGURE 3
CO₂ SOLUTION ISOTHERM IN TEA AND MDEA
FIGURE 4
BASF TEA WASH PROCESS

- TREATED GAS TO ALKAZID PROCESS
- FLASH GAS
- ACID GAS

FLOW DIAGRAM:
- RAW GAS to ABSORBER
- FLASH DRUM
- MAIN CIRCULATION PUMP
- PARSONS
FIGURE 5
BASF ACTIVATED MDEA PROCESS

TREATED GAS

LEAN SOLUTION COOLER

LEAN/RICH EXCHANGER

CO2 VENT GAS

L.P. STEAM

H.P. FLASH GAS

ABSORBER

L.P. FLASH DRUM

H.P. FLASH DRUM

R.EGENERATOR

RAW SYNTHESIS GAS

HYDRAULIC TURBINE

MAIN CIRCULATION PUMP

PARSONS
<table>
<thead>
<tr>
<th>TABLE I</th>
<th>GAS TREATING PROCESSES AVAILABLE</th>
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<tbody>
<tr>
<td>• CHEMICAL SOLVENTS</td>
<td></td>
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<tr>
<td>— MEA</td>
<td></td>
</tr>
<tr>
<td>— DEA</td>
<td></td>
</tr>
<tr>
<td>— ACTIVATED HOT CARBONATE</td>
<td></td>
</tr>
<tr>
<td>— ACTIVATED MDEA</td>
<td></td>
</tr>
<tr>
<td>• PHYSICAL SOLVENTS</td>
<td></td>
</tr>
<tr>
<td>— SELEXOL</td>
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<td>— SEPA SOLV MPE</td>
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<tr>
<td>— RECTISOL</td>
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<tr>
<td>— PURISOL</td>
<td></td>
</tr>
<tr>
<td>• OTHER</td>
<td></td>
</tr>
<tr>
<td>— PRESSURE SWING ADSORPTION</td>
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</tr>
<tr>
<td>TABLE II</td>
<td>GAS TREATING PROCESS SELECTION CRITERIA</td>
</tr>
<tr>
<td>----------</td>
<td>-----------------------------------------</td>
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<tr>
<td>• MINIMUM NUMBER OF SOLVENTS</td>
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</tr>
<tr>
<td>• COMMERCIAL EXPERIENCE</td>
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<tr>
<td>• ENERGY REQUIREMENTS</td>
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<tr>
<td>• TREATED GAS SPECIFICATION</td>
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<tr>
<td>• BY-PRODUCT FORMATION</td>
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</tr>
<tr>
<td>• CAPITAL COST</td>
<td></td>
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<tr>
<td>• OPERATING COST</td>
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</tr>
<tr>
<td>• ACID GAS COMPOSITION</td>
<td></td>
</tr>
<tr>
<td>• CORROSION</td>
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## TABLE III
### AMINE REACTIONS

#### PRIMARY AND SECONDARY AMINES

\[
\begin{align*}
RR'NH + CO_2 &= RR'NCOO^- + H^+ \\
RR'NCOO^- + H_2O &= RR'NH + HCO_3^- \\
RR'NH + H_2S &= RR'NH_2^+ + HS^-
\end{align*}
\]

#### TERTIARY AMINES

\[
\begin{align*}
R_2NR' + CO_2 &= \text{NO REACTION} \\
R_2NR' + CO_2 + H_2O &= R_2NHR'^+ + HCO_3^- \\
R_2NR' + H_2S &= R_2NHR'^+ + HS^-
\end{align*}
\]
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<tr>
<th>COMPONENT</th>
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<td>H₂</td>
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<tr>
<td>CO</td>
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<tr>
<td>CO₂</td>
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<tr>
<td>CH₄</td>
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<tr>
<td>AR</td>
<td>.27</td>
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<tr>
<td>H₂S</td>
<td>.10</td>
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<tr>
<td>N₂</td>
<td>.21</td>
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**TOTAL** 100.00

**FLOW RATE, MMSCFDD** 62.4
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<td>N₂</td>
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<td>AR</td>
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<tr>
<td>CO</td>
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<td>CO₂</td>
<td>16.9</td>
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<tr>
<td>CH₄</td>
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**TOTAL** 100.0

**FLOW RATE, MMSCFD** 161.4
<table>
<thead>
<tr>
<th></th>
<th>DEA</th>
<th>ACTIVATED MDEA</th>
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<tr>
<td>FEED GAS RATE, MMSCFD</td>
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<tr>
<td>CO₂ CONTENT, VOL. %</td>
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<td>PRESSURE, PSIG</td>
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<td>950</td>
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<tr>
<td>TREATED GAS SPECIFICATION, VOL. %</td>
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<tr>
<td>SOLUTION CIRCULATION, GPM</td>
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<tr>
<td>REBOILER HEAT INPUT, MMBTU/HR</td>
<td>10</td>
<td>0</td>
</tr>
</tbody>
</table>
PLANNING PETROCHEMICAL COMPLEXES

BASED ON NATURAL GAS

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M. J. Maddock, Manager, Process Planning & Economics
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INTRODUCTION

This symposium is focused on Thailand's long term plans for the utilization of natural gas. The cornerstone of the plans include the present construction of a 350 million cubic feet per day gas separation plant. The gas plant will produce methane off-gas, LPG for domestic needs and ethane and propane feedstocks for the planned petrochemical complex. The methane off-gas will serve as a feed for the fertilizer complex.

The core unit of the planned Thai petrochemical complex includes olefin units to produce ethylene and propylene as basic petrochemicals that can serve as raw materials for the manufacture of petrochemical intermediates and end-products ranging from plastics and resins to synthetic rubber and building materials.

This paper outlines the long range planning, project planning and project execution steps associated with the development of a petrochemical complex.

The complex and interrelated nature of the multi-unit process plants in a petrochemical complex requires special expertise during the conceptual technical planning and economic optimization phases of a project. The decisions that are made in the early stages of a project have the most significant economic impact on a project. As a consequence for these large and capital intensive projects, the planning and optimization phase is perhaps the single most important step in the series of events beginning with general concepts and culminating in a smoothly operating and profitable commercial plant.

The factors that have to be evaluated in the planning of a petrochemical project are:

1. Petrochemical Feedstock Availability
2. Present and Future Petrochemicals Market Demand
3. Project Feasibility
4. Project Execution Plan

The orderly development of a successful project would involve the following steps:

PETROCHEMICAL FEEDSTOCK AVAILABILITY

Though a petrochemical complex could be developed solely on ethylene, production of propylene and butadiene would allow for a wider range in finished products flexibility. Ethylene can be produced in the olefin unit by cracking ethane, but in order to produce significant quantities of propylene, propane and heavier feedstocks must be cracked
One of the major considerations in the olefin unit design concerns the selection of the conversion level per pass in the cracking heaters. The olefin unit investment is generally reduced by high conversions minimizing heater recycle and hence plant throughput. The economics and operability of an ethane cracker normally result in conversion levels per pass in the range of 55-65%. The corresponding conversion levels for co-cracked propane are 90-95%. Typical high conversion levels for ethane pyrolysis, with both ethane and co-produced propane recycled to extinction, are 80-85 wt.% ethylene depending upon furnace type and operating conditions.

Pyrolysis of propane at high conversion produces mainly ethylene. For example, with both propane and co-produced ethane recycled to extinction, typical pyrolysis yields for propane feed at high conversion are:

- Ethylene: 40-45 wt.%
- Propylene: 14-12 wt.%

At lower propane conversion levels, higher propylene/ethylene ratios are realized. For example, typical yields for propane feed at low conversion are:

- Ethylene: 39-40 wt.%
- Propylene: 27-24 wt.%

Typical pyrolysis yields for ethane and propane are illustrated in Table 1. More selective yields may be obtained with different pyrolysis heaters, but the yield trends are similar with high propylene to ethylene ratios only realized at low propane conversions per pass.

Alternatively, propane catalytic dehydrogenation may be used to improve the propylene yield. In the case of the planned Thai petrochemical complex, the proposed combined olefin unit and propane dehydrogenation units results in the minimum total feedstock for the required ethylene and propylene production rates.

In Table 1 we can also see that relatively small quantities of butadiene are produced when cracking ethane and propane. However, large tonnages of butadiene can be produced via dehydrogenation of the normal butane in natural gas. In fact, the bulk of the butadiene produced in the United States utilizes this method. However, it is unlikely future plants of this type will be built in the U.S. since future butadiene will probably be recovered from heavy feedstock (i.e. naphtha, gas oil) crackers.

For long range planning alternative feedstocks will be required to meet the demands for other petrochemical intermediates. In particular, there will be a demand for aromatics which could be produced from naphtha by catalytic reforming/aromatics extraction processes.
PRESENT AND FUTURE PETROCHEMICALS MARKET DEMAND

In developing a long range plan for a petrochemical complex, companies will generally select those products which will satisfy current market requirements, have potentially high growth rates, and which can be produced from the available and domestic raw materials. In addition, the companies must anticipate which manufacturing facilities will be available to process their semi-finished products into finished products, and be able to market their products in the event that such manufacturing facilities do not exist.

The major building blocks which are the foundation of the petrochemical industry are the unsaturates (ethylene, propylene, butenes, butadiene), and the aromatics (benzene, toluene and xylenes).

The end uses consist of a very wide variety and cover a vast field. The following lists the major end uses of the most common petrochemicals.

<table>
<thead>
<tr>
<th>Major Petrochemical</th>
<th>Major End Uses</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) Plastics</td>
<td></td>
</tr>
<tr>
<td>Low and linear low</td>
<td>Film for packaging, paper coating,</td>
</tr>
<tr>
<td>density polyethylene</td>
<td>wire cable insulation, agriculture,</td>
</tr>
<tr>
<td>(LDPE-LLDPE)</td>
<td>storage tanks, trash containers,</td>
</tr>
<tr>
<td></td>
<td>toys, marine floatation devices,</td>
</tr>
<tr>
<td></td>
<td>sporting goods, floor underpads</td>
</tr>
<tr>
<td>High density poly-</td>
<td>Containers for liquids, household,</td>
</tr>
<tr>
<td>ethylene (HDPE)</td>
<td>personal care bottles, bags,</td>
</tr>
<tr>
<td></td>
<td>structural parts, i.e., pallets,</td>
</tr>
<tr>
<td></td>
<td>crates, machine housing, pipes.</td>
</tr>
<tr>
<td>Polypropylene (PP)</td>
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<td>fibers for carpeting, upholstery,</td>
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<td>industrial containers, produce bins,</td>
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<td></td>
<td>trays, automotive parts</td>
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<td>Polyvinyl chloride</td>
<td>Floor tiles, wall covering, pipes</td>
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<td>(PVC)</td>
<td>and fittings, electrical conduits,</td>
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<td></td>
<td>packaging film, rigid bottles,</td>
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<td></td>
<td>cosmetics, house siding, carpet</td>
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<td>backings</td>
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<tr>
<td>Polystyrene (PS)</td>
<td>Packaging - food produce containers,</td>
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<tr>
<td></td>
<td>trays, ethical drug containers,</td>
</tr>
<tr>
<td></td>
<td>disposable dinnerware, furniture</td>
</tr>
<tr>
<td></td>
<td>industry - panels, frames, audio</td>
</tr>
<tr>
<td></td>
<td>cassettes</td>
</tr>
</tbody>
</table>

526
<table>
<thead>
<tr>
<th>Major Petrochemical</th>
<th>Major End Uses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Styrene Copolymers -</td>
<td>Clear food containers, boxes</td>
</tr>
<tr>
<td>with butadiene</td>
<td>Battery cases, refrigerator drawers, trays, vacuum cleaner parts, humidifier parts</td>
</tr>
<tr>
<td>with acrylonitriles</td>
<td></td>
</tr>
<tr>
<td>(SAN)</td>
<td></td>
</tr>
<tr>
<td>Phenolic resins</td>
<td>Auto body tops, handles, knobs, electrical appliance bases, switch gears, circuit breakers</td>
</tr>
<tr>
<td>b) Elastomers</td>
<td></td>
</tr>
<tr>
<td>Copolymers</td>
<td></td>
</tr>
<tr>
<td>Styrene/Butadiene</td>
<td>Synthetic rubber, pipe, automotive components</td>
</tr>
<tr>
<td>Acrylonitrile-(ABS)</td>
<td>Appliance components, components for business machines, telephones</td>
</tr>
<tr>
<td>Butadiene-Styrene</td>
<td></td>
</tr>
<tr>
<td>c) Filaments, yarn</td>
<td></td>
</tr>
<tr>
<td>Poly (glycol) esters</td>
<td>Staple fibers, filament yarn</td>
</tr>
<tr>
<td>Acrylics</td>
<td></td>
</tr>
<tr>
<td>Caprolactams - nylon</td>
<td></td>
</tr>
<tr>
<td>d) Detergents</td>
<td></td>
</tr>
<tr>
<td>Linear Alkyl Benzene</td>
<td>Industrial detergents, emulsifiers</td>
</tr>
<tr>
<td>Linear Alcohol Ethoxy-</td>
<td>Surfactants</td>
</tr>
<tr>
<td>lates</td>
<td></td>
</tr>
<tr>
<td>e) Cosmetics</td>
<td></td>
</tr>
<tr>
<td>Various alcohols, esters</td>
<td>Cosmetics, fragrances</td>
</tr>
<tr>
<td>f) Agriculture</td>
<td></td>
</tr>
<tr>
<td>Specialty synthetic com-</td>
<td></td>
</tr>
<tr>
<td>pounds</td>
<td>Pesticides, Rubicides</td>
</tr>
<tr>
<td>Ammonia, urea</td>
<td>Fertilizers</td>
</tr>
</tbody>
</table>

Many developing countries have a national commitment to the development of large numbers of relatively small labor intensive manufacturing facilities based on the ample supply of semi-finished petrochemical products. Similarly these same production facilities might be geared to the production of consumer-oriented products which would help stimulate economic growth. For example, the history of the petrochemical industry development in Taiwan and South Korea has shown dramatic growth in the petrochemical end user units following the establishment of the basic petrochemical industry. The spectacular recent growth of petrochemicals in the 70's in Taiwan and South Korea is shown as follows.
**Petrochemical Summary**

<table>
<thead>
<tr>
<th>Year</th>
<th>South Korea</th>
<th>Taiwan</th>
<th>Total Petrochemical Production (MT/Yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1970</td>
<td>--</td>
<td>35,000</td>
<td>South Korea 940,000 Taiwan 190,000</td>
</tr>
<tr>
<td>1972</td>
<td>150,000</td>
<td>55,000</td>
<td>South Korea 1,805,000 Taiwan 255,000</td>
</tr>
<tr>
<td>1980</td>
<td>500,000</td>
<td>473,000</td>
<td>South Korea 3,700,000 Taiwan 1,805,000</td>
</tr>
</tbody>
</table>

(Population: South Korea 37 MM, Taiwan 17 MM)

The availability of the intermediate petrochemical products has accelerated small fabricating company growth so that there are now over 440 companies in Taiwan and 570 in South Korea that are engaged in the processing and fabrication of plastic and plastic-related products.

Typically the market study required to define a petrochemical complex includes a domestic market study, a regional export study and examination of product distribution alternatives.

Major questions that have to be answered are:

- Should the project size be based on marketing to export customers in addition to domestic customers?
- What is the best product mix and initial capacity for the project?
- Should the project follow a phased development?

**Export/Domestic Market Evaluation**

A decision on basing the project size on only the domestic market or on an export/domestic market mix will have a major impact on the project size and economics of production.

Factors to be evaluated in the domestic market study should include:

- An analysis of petrochemical use, population, GNP, and other pertinent statistical data
- Present use patterns for petrochemicals
- New market potential
- Current pricing, import duties and how they would change with the new project
- Estimate of domestic demand growth and comparison with similar developing countries

Export market studies should include:
- Identification of potential regional export markets
- Estimate of supply/demand position for regional markets as well as potential for market share
- Economic incentives for exporting.
- Trading agreements, import duties, taxes, freight and transportation costs and other cost factors

Certainly, the decision to serve export markets has a higher risk factor. If this approach was selected, consideration should be given to a joint venture marketing agreement with international marketing companies.

**Product Mix/Initial Capacity of Project**

Many of the questions on product mix and initial capacity of the project are answered by the market study. However, other factors that have to be considered include:
- Feedstock Availability
- Comparison of Alternate Feedstocks
- Capital Limitations
- Feedstock Pricing

**Phased Development of the Project**

Market factors, capital limitations, human resources and infrastructure needs generally result in a phased development for petrochemical industries.

Figure 1 illustrates a potential long range plan for the development of a natural gas based petrochemical industry with ethylene, propylene and butadiene as basic derivatives. In Figure 1, the boxes and lines drawn in bold type represent suggested derivatives for a petrochemical core complex to be set up in a country with little or no petrochemical industry. Some of the elements in this long range plan are included in the Thailand plan.
The next phase in the development of a petrochemical industry could include the production of aromatic feedstocks and expansion of fiber industries including acrylonitrile, ethylene oxide, and other essential petrochemical products.

With a population of 48 million people Thailand has sufficient base-load domestic demand to justify the development of a core olefin complex. Thai projected demands for selected major olefin derivatives are:

<table>
<thead>
<tr>
<th>Product</th>
<th>Imports (tons per year)</th>
<th>Projected Demand (tons per year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LDPE</td>
<td>36,800</td>
<td>39,500</td>
</tr>
<tr>
<td>HDPE</td>
<td>32,300</td>
<td>42,000</td>
</tr>
<tr>
<td>PP</td>
<td>43,300</td>
<td>57,200</td>
</tr>
<tr>
<td>VCM</td>
<td>27,200</td>
<td>45,800</td>
</tr>
</tbody>
</table>

Based on this market information the Thai Petrochemical Complex has elected to build a core olefin unit sized to produce 300,000 tons/yr of ethylene and 73,000 tons/yr of propylene with the following downstream products to meet 1990 market demands:

- LDPE: 73,000 MTA
- HDPE: 110,000 MTA
- Polypropylene: 70,000 MTA
- VCM/PVC: 80,000/30,000 MTA

PROJECT FEASIBILITY STUDY

Using the information obtained in the market and feedstock studies, a project feasibility study is made to match up identified markets and the available feedstocks. The goal of the feasibility study is to perform all of the needed engineering, costing, planning, and financial analysis to fully define the proposed petrochemical complex. This phase of the study must be accomplished in sufficient detail to allow for its presentation to prospective investors and financial institutions as well as providing the basis for design of the project. Table 2 presents an outline of the items that should be investigated in the detailed techno-economic study. All of this information is organized into the feasibility study report. The report provides the project sponsors with a firm basis to make the final decisions on the petrochemical complex. Since modern petrochemical installations are very expensive and are built to last for many years, the time and effort spent in the planning process may be amply justified.
**TABLE 1**

**ETHANE AND PROPANE PYROLYSIS YIELDS**

<table>
<thead>
<tr>
<th></th>
<th>60% Ethane Conversion</th>
<th>75% Propane Conversion</th>
<th>93% Propane Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Theoretical Ultimate (1)</td>
<td>Theoretical Ultimate (2)</td>
<td>Theoretical Ultimate (2)</td>
</tr>
<tr>
<td>Hydrogen &amp; Methane</td>
<td>12.90</td>
<td>27.53</td>
<td>30.79</td>
</tr>
<tr>
<td>Ethylene</td>
<td>80.90</td>
<td>39.54</td>
<td>44.08</td>
</tr>
<tr>
<td>Propylene</td>
<td>1.84</td>
<td>24.88</td>
<td>12.57</td>
</tr>
<tr>
<td>Propane</td>
<td>0.31</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Butadienes</td>
<td>1.86</td>
<td>1.47</td>
<td>3.33</td>
</tr>
<tr>
<td>Butylenes</td>
<td>0.35</td>
<td>1.82</td>
<td>1.00</td>
</tr>
<tr>
<td>Butanes</td>
<td>0.45</td>
<td>0.09</td>
<td>0.09</td>
</tr>
<tr>
<td>C5 and Heavier</td>
<td>1.39</td>
<td>4.67</td>
<td>8.14</td>
</tr>
<tr>
<td>TOTAL</td>
<td>100.00</td>
<td>100.00</td>
<td>100.00</td>
</tr>
</tbody>
</table>

(1) Theoretical yield when acetylene, methylacetylene and propadiene are hydrogenated to ethane and propane respectively, and when ethane is recycled to extinction.

(2) Same as (1) with ethane and propane both recycled to extinction.
Table 2
Detailed Techno-Economic Study Outline

1. A technical and investment cost study including:
   a. Selection of the technologies to be used.
   b. A process schematic flow diagram showing material and energy balances.
   c. Land cost.
   d. A list and specifications of offsite facilities required.
   e. A list of all chemical and catalyst consumption rates.
   f. A plot plan.
   g. A cost estimate for the process and support facilities.
   h. A schedule of royalties and license fees.
   i. An estimate of the cost of spare parts required.
   j. Start-up cost including training.
   k. A breakdown of the cost into local currency and foreign exchange costs.
   l. A project cash flow projection based on the investment estimates.

2. An operating cost study including:
   a. Raw material, fuel, power, catalyst and chemical consumption per ton of product.
   b. Debt service, depreciation, insurance, taxes, and other fixed costs.
   c. Cost of labor and supervision.
   d. Shipping and transportation costs.
   e. Maintenance costs and spare parts replacement estimate.
   f. Overall production costs at various production levels.
3. A competitive cost analysis to compare the overall production cost determined above with both domestic prices and pricing in the international export market. For both cases the breakeven productivity level is computed.

4. A sensitivity analysis to examine the petrochemical complex's sensitivity to variations in feedstock and product prices and production levels.

5. An estimate of the foreign exchange savings which would be realized by the construction of the petrochemical complex in terms of both savings derived from the substitution of domestically produced products for imported products as well as the net foreign exchange gained by exporting domestically produced products.

6. A financial analysis of the proposed petrochemical complex over a 20-year period starting from the initiation of design work.
FIGURE 1 LONG RANGE PETROCHEMICAL COMPLEX
PROJECT EXECUTION PLAN

Following the feasibility study, the Project Execution Plan normally comprises the following major tasks:

- Selection of Managing Contractor
- Licensor and Technology Selection
- Solicitation of Bids/Award of Contracts
- Design and Procurement
- Construction
- Training
- Commissioning and Startup
- Initial Operation and Optimization

Selection of Managing Contractor

The managing contractor plays a vital role in the successful completion of the complex. The managing contractor must provide the experience, people, and systems necessary to properly represent the owners' interest while ensuring the successful design, construction and startup of the complex. The managing contractor is responsible to develop the detailed project execution plans that supervise, coordinate, and monitor the activities in the complex. There are certain criterion that a managing contractor must meet in order to successfully complete a job of this magnitude. The following criterion should be evaluated during the selection of a managing contractor:

A. The contractor should be a full scope company experienced in all phases of project management including design, construction, training, commissioning and startup of the project.

B. The contractor should have the engineering, procurement, and construction staff and all of the supporting disciplines necessary to provide effective overall coordination of the complex between the licensors of technology and the subcontractors who will construct the individual plants and support facilities.

C. The contractor should have in-house proven procedures, techniques, methods, specifications, and standards which can be applied to the planning, estimating, controlling, and coordinating the full scope of the complex.

D. The contractor should have international experience in building a grass roots petrochemical complex. Broad international experience is important in that worldwide procurement will be used to minimize costs. The logistics of dealing with worldwide suppliers are overwhelming unless the contractor has the experience, capability and facilities to handle.
E. The contractor should have the necessary qualified personnel required for the commissioning of the complex.

F. For a grass roots installation in Thailand it is important that the contractor has experience in training the owner's personnel and/or local personnel in the construction and operation of the complex.

G. Finally, the contractor should have experience in licensor selection and design of units based on licensed technology.

The extent of the managing contractor's involvement in the project will depend on the owner's requirements.

Licensor and Technology Selection

The managing contractor usually conducts a licensed technology evaluation on behalf of the client. The contractor begins by drawing up a list of potential licensors and the factors that will be used to compare the technologies. The list of factors includes not only the tangible economic factors (yields, costs, number of units, etc.) but intangible items such as:

- Is the licensor continuing to invest R&D money in the process
- Will the licensor supply training in his own plants
- What is the history of training and startup for previous units
- What technical back-up and service is available
- How many qualified startup personnel are available
- Is there an alternate supplier of any key catalyst or chemicals used by the technology

The relative importance of each of the factors is jointly determined by the contractor and the owner(s). Inquiries are prepared and transmitted to the licensors. Since much of the data is confidential, secrecy agreements are needed. Some contractors, such as Lummus, maintain current agreements with most licensors so that no time is lost obtaining these agreements. Following responses to the inquiries, meetings with licensors are held and as needed plant visits are made. After review and a joint meeting, the licensors are short listed for negotiation and a final report issued with the blind coding removed. The contractor provides technical assistance during the negotiation and final selection of licensors.

Using the data obtained from the licensor selection phase a preliminary overall material and energy balance is prepared along with preliminary estimates for the central utilities plant and a plot plan. This information along with instructions regarding operating and design philosophy are transmitted to the licensors for preparation of the basic engineering (black book) packages. During the preparation of the basic engineering packages the managing contractor coordinates the activities to ensure the integration of process units with central utilities and supporting facilities.
Solicitation of Bids & Award of Contracts

Concurrent with the Licensor Selection, the managing contractor also develops the operating philosophy, design criteria, standards and specifications for the complex. Certain preparatory contracts are let early such as soil investigations, transportation and marine surveys, and environmental studies. As the process design packages become available the final material and energy balance is prepared. The plot plan is developed. The central utility and supporting facility are also defined.

All of the above information, specifications, and standards are incorporated into "Invitation to Bid" (ITB) documents for all the units in the complex. It has been our experience that the best way to positively control the scope of the engineering contractors work is to define it as a fully-developed specification package developed by the managing contractor, under the direction of the Owner before commencing design and procurement activities. In this way there is no doubt as to what type of equipment or system the owner wants in the plant. The owner working through the managing contractor has made these decisions and recorded them in the specifications.

A further advantage of gathering together the technology packages from the licensors, the design criteria desired by the owner and the engineering standards to be used into one ITB for each process area plus the integrated offsites is the assurance of uniformity and coordination that it gives. Although it can be argued that going directly from the licensor's technology packages into the construction contractors' detailed design might save some time and manhours, the experience of many operating companies has shown that the savings in execution of the project afforded by tighter control and other coordination easily offset these costs. The savings in execution include reductions in change orders, extras and construction schedule.

A short list of qualified engineering contractors is jointly developed between the owner and the managing contractor and the owner and the managing contractor and the ITB documents are transmitted to the selected contractors. The owner will determine the basis upon which the work will be bid. The bases on which the work can be bid include:

- Fully reimbursable
- Lump sum for engineering services and reimbursable for the remainder
- Lump sum, turn-key for all activities

The managing contractor assists the owner in evaluating the bid responses and the owner awards the contracts.
Design and Procurement

During the design and procurement stages the managing contractor will be able to monitor, coordinate, and control the engineering contractors on behalf of the owner.

Principal responsibilities during the design phase includes the following:

A. Monitor cost, schedule, and quality of the engineering contractor's work.

B. Approve with Owner, any changes of scope arising from the contractors' work.

C. Coordinate the utilities connections between the various units and the central utility plant.

D. Respond to adverse cost or schedule trends by the engineering contractors and follow up on their corrective actions.

E. Development of a coordinated effluent treating system for the complex.

In a location that is somewhat remote from the principal sources of supply, equipment standardization can be very advantageous. A major benefit of standardization is in the reduced inventory of spare parts. With interchangeability, maintenance and supply problems are reduced. Another benefit is that it is simpler to train employees on one type of item rather than several. The benefits of standardization are most readily seen in the field of instrumentation. New operators or maintenance men do not have to be trained on several types of instruments each performing similar functions.

Responsibilities of the managing contractor during the procurement phase of the project include:

A. Monitor and coordinate among the contractors all purchasing, expediting, inspection and traffic activities.

B. Assist the owners' group in negotiation with selected vendors to implement large volume purchasing of standardized equipment and commodities.

C. Insure the use of common commodity codes in order to simplify field tagging.

D. Coordinate contractors' equipment purchasing to avoid overloading shops and conflict among purchasing efforts between the various contractors.
E. Provide import instructions and monitor material shipments to Thailand.

F. Provide the owner with updated schedules and costs of the procurement activities.

G. Respond to adverse schedule or cost trends or equipment purchases which are not consistent with the owner's standards or specifications.

Construction

Achieving an orderly construction and erection program consistent with maintaining the project schedule and budget is the primary responsibility of the managing contractor during the construction phase. Coordination of the construction contractors during this phase is all important since this phase normally last 2-3 years and thousands of workers are crowded into a congested area. Conflicts arise which must be quickly resolved to maintain cooperation between the various subcontractors. The managing contractor provides a team of personnel for each subcontractor to monitor and coordinate the activities in the field. These teams review the programs of the work and coordinate and provide the communications between the subcontractors. The managing contractor also provides timely reporting to the owner as to the status of the job in relation to the overall schedule and budget.

In addition to the coordination activities the managing contractor often provides the following services:

A. Site definition including baselines, benchmarks, marshalling areas, process areas and labor camp areas.

B. Establishment and maintenance of a master engineering, procurement, and specification files.

C. Witness equipment tests and record the results.

D. Development of an overall manpower plan to establish the skills and number of men needed, resources available, cultural considerations, and training requirements.

E. Development of an overall quality assurance plan. Review of quality control plans prepared by individual subcontractors.

F. Preparation of a master safety plan for the project. Review and monitor individual subcontractors' plans and performance.

G. Administration of change orders. A formal change order system is developed to ensure that each change request is justified before being approved.
Training

The training activity starts soon after the selection of technology and continues all through the remainder of the job. The managing contractor assists the owner in providing training for the owner's personnel who will supervise, operate, and maintain the complex. Training of the craft people who will construct the plant is accomplished by the engineering contractors, and the managing contractor provides coordination services between the contractors to ensure maximum participation of local Thai personnel. Many of the Thai craft people trained to construct the plant will ultimately be employed in the maintenance areas of the complex. The training cycle extends over several years and includes the following steps:

A. Determination of training requirements. In this step organization charts, job descriptions, and skills needed are determined. The local available labor force is examined and the training needs determined.

B. Develop the training program. Here the training manual, lesson plans, performance standards and schedules are prepared. The location of training centers are fixed and arrangements for training at licensor plants are made.

C. Organize the training infrastructure. Training aids, simulators housing, and training facilities are prepared. The instruction staff, which will be composed primarily of future supervision of the joint venture, is trained first.

D. Conduct the training program. In this step trainees are trained, tested, and assigned to jobs.

A recent trend in training has been the preparation of a training simulator. The simulator is based on a computer simulation of units in the complex which provides realistic responses to both normal and emergency operation. If the complex will include computer control, then the simulation package is installed at the complex. All of the training aids are transferred to the owner and a follow-up training program continues until after startup to ensure that the owner can continue training in the future.

Commissioning and Startup

Historically a good startup will cost about 6-8% of the total installed cost of the plant while a protracted startup can run as high as 20% of the cost of the plant. Planning for commission and startup is essential and time well spent. The planning should begin right after the construction contractors are selected. A team consisting of the owner's staff (including the plant manager, maintenance manager, and technical manager), representatives from the construction contractors and the initial operations group of the managing contractor is formed to plan the commissioning and startup activities. This group performs the following functions:
A. During the Basic Engineering
   - P&I Review
   - Safety Review
   - Operating Manuals Preparation

B. During Plant Construction
   - Determine startup schedule
   - Inspection of equipment, vessel internals, piping and instrumentation
   - Develop detailed procedures for commissioning, startup and emergencies

C. During Commissioning
   Supervise all commissioning activities including:
   - Equipment run-in
   - Instrument and control system checkout
   - Cleaning, purging and inerting
   - Refractory dryout
   - Preparation of punch lists and verification of corrections

D. During Startup
   - Supervise the startup
   - Conduct performance tests
   - Document performance or utility deviations from guarantees and notify licensor and constructor.

Initial Operations and Optimization

Following the acceptance of all units there is a period of initial operations during which the complex settles down into routine operation and overall complex is optimized. The construction contractors have left and the representatives of the licensed technologies have also left. During this period the managing contractor's initial operations group completes training of the operators and prepares operating material and utility balances. Adjustments are made to optimize performance of the complex and bottlenecks are identified. The initial operations group continues to provide technical support and assists the owners' operating group in technical troubleshooting and cost reduction programs. All documentation and files are organized and turned over to the client. Finally, solutions to bottlenecks are proposed. The startup team remains as long as the owner feels the need for them to remain.
Summation

The construction of a Petrochemical Complex such as the one being planned is a large and complex task. It is an activity that takes several years and involves thousands of workers. However, the task can be managed by careful planning. The steps outlined in this paper have been used by Lummus to construct similar petrochemical projects with good results and are offered as a guide to your planning. The steps taken thus far form a firm foundation for further planning and a commercial project.
1. **INTRODUCTION**

Thailand is one of ten food exporting countries in the world and the only Country in Asia that has been a surplus food exporter over the past twenty years.

Thailand's agriculture accounts for approximately 25% of its gross national product (36 billion dollars in 1981). Seventy percent of the country's population is employed in agriculture activities and 60% of foreign exchange earning is related to agriculture products.

These few data are sufficient to demonstrate the importance of the agriculture factor in the Thai economy.

There are, however, a number of weak points in the agriculture sector which require the proper attention and the necessary corrective actions. One of these is the productivity. In the past twenty years, agriculture production has scored an impressive average increase equal to 5% per annum (twice the world average). This growth was achieved mainly by expanding the area under cultivation rather than by increasing land productivity, to the point that now Thailand has reached the limit of good quality new land that can be brought into production. Another serious problem is the decline in base fertility because of a net removal of plant materials from the fields. It has been estimated that in 1981 the crops harvested removed from the soil of Thailand 633,000 tons of N₂, 271,000 tons of P₂O₅ and 341,000 tons of K₂O. In the same year only 162,000 tons of N₂, 126,000 tons of P₂O₅ and 35,000 tons of K₂O were applied to the soil.

From this data it is evident that the current practice removes the natural fertility of the soil at a rapid rate. In 1981, only 25% of N₂, 46% of P₂O₅ and 10% of K₂O consumed were returned to the soil. The recent slowing down of
agriculture production, from 5% to 3.5% per annum, is a consequence of these two negative factors, the reaching of the limits in the expansion of the cultivated area and the depletion of the natural fertility.

The Fifth National Economic and Social Development Plan (1982-1986) has established a target for expansion of agriculture production of 4% per year. This can only be achieved by a more intensive use of fertilizers, an expansion of the irrigation system and the use of modern high yielding seeds. Without proper use of these factors, agriculture growth will fall to 2.7% in 1986.

Thailand ranks among the lowest in Asia in fertilizer use per hectare. In Table 1, we have examined 20 Asian countries which can be placed into three categories in accordance with their intensity of fertilizer use (kg of N/ha) and yields of rice (t/ha). Group I (Japan, South Korea and Taiwan), has a rice yield of 6 T/ha and rates of N usage of 200 Kg N/ha. Group II (Malaysia), has respectively 4 t/ha and 85 kg/ha. In contrast, the countries in Group III, one of which is Thailand, have a rice yield of 2 t/ha and N usage of 25 Kg/ha. Thailand, in 1979, averaged only 1.8 tons of rice per hectare and used only 15 Kg of N per hectare. Figure 1 gives the consumptions of fertilizer in Thailand in the past 15 years. Table 2 gives in absolute values the consumption of fertilizers in Thailand in 1981, the estimated annual percentage increase, by fitting regression models to historical data, the projected consumption in 1992, and the so-called agronomic potential in 1980, which represents the consumption in 1980 if farmers used fertilizers at the recommended rates. All these data demonstrate the existence of extensive room for expansion in fertilizer use, provided the major constraints are removed, such as the lack of domestic fertilizer production, high prices of fertilizers, inconsistent crop pricing policies, and lack of adequate research and educational programs.
2. **SIZE AND CONFIGURATION OF THE FERTILIZER COMPLEX**

The discovery of substantial offshore gas reserves in the late 1970's has created the premises for a long-overdue chemical fertilizer complex in Thailand. This project has since been incorporated as a key component of the Eastern Seaboard Industrial Development Program.

In 1982, National Fertilizer Corporation, a joint venture company of Thai public and private investors, selected Foster Wheeler International Corporation as consultant for a comprehensive Feasibility Study of the project.

Based on a conservative approach with regard to NFC's ability to penetrate the fertilizer market in Thailand, the fertilizer complex has been sized to meet the 1992 domestic demand of nitrogen, phosphorus and potassium by 75%, 95% and 75% respectively. This approach will also allow room for future imports from two endorsed ASEAN urea projects in Malaysia and Indonesia.

Table 3 reports the total Thai consumption of N, P$_2$O$_5$ and K$_2$O and the complex capacity as projected NFC sales.

During the Feasibility Study a large number of alternative configurations of the complex were studied to determine the optimum final configuration. Initially, 14 configurations were selected for the analysis, covering the range of different raw materials, different processing routes, different plant locations and various impacts of the existing fertilizer ASEAN projects. Table 4 summarizes the characteristics of these configurations.

Each configuration was evaluated on a comparative basis by determining a number of parameters such as investment cost, working capital, operating costs, cost of production per ton of nutrient, and yearly foreign currency expenditure.
The result of this first techno-economic screening was to reduce the number of configurations from 14 to 4, which were subsequently the subject of a more detailed evaluation study.

Configuration 1 is based on phosphate rock and sulfur import and produces MAP, DAP and urea (see Fig. 2). Configuration 2 is based on phosphate rock and sulfur import, but relies on the soda ash project to convert ammonia to a solid product (ammonium chloride) (see Fig. 3).

Configuration 3 is also based on import of phosphate rock and sulfur but produces, besides MAP, DAP and urea, a large number of NP - NPK fertilizer grades (see Fig. 4).

Configuration 4 is based on import of phosphoric acid and produces MAP, DAP and urea (see Fig. 5).

For each configuration a complete profitability analysis was implemented, taking into account various economic scenarios during the life of the project. The profitability analysis was supplemented by an extensive sensitivity analysis to determine the effect on profitability of the various major economic parameters such as price of natural gas and other raw materials, price of products, capital investment, rate of production in the first years of operation, etc.

Rate of return on total investment ranged from a minimum of 10% for Configuration 4 to a maximum of 14% for Configuration 1.

Based on the result of the profitability analysis and on the flexibility of meeting the agronomic demand of the Thai crops, Configuration 3 was selected for a more in-depth technical-economic evaluation which constituted the final stage of the Feasibility Study, which ended in August 1983.
The investment cost of the complex, based on the definition of the Feasibility Study, runs to U.S. dollars 464 million, at constant 1983 prices. Adjusted for inflation, the capital cost would run to U.S. dollars 572 million by the end of 1987, when construction is scheduled to be completed.

Working capital, interest during construction, and start-up costs must be added to the capital cost given above.

The estimated rate of return is 12.7% on a discounted cash flow basis.

The borderline profitability is, however, supported by other reasons, which are making this project a first priority in the Government planning, such as the benefit to Thai farmers in securing a reliable supply of competitively priced fertilizers.

3. PROJECT IMPLEMENTATION PROGRAM

In October 1983, the implementation program of the fertilizer complex started with the nomination by NFC of FWIC as Project Management Consultant.

The present program foresees two phases.

Phase 1 includes the following activities:

- Final optimization of the processing scheme
- Preparation and issue of "Invitation to Bid" packages
- Bid evaluations
- Contract negotiations
- Preparation of Environmental Impact Statement
Phase 2 covers the detailed design, procurement and construction of the complex. Figure 6 presents the overall project schedule which foresees the commissioning of the complex in the second half of 1987.

The basic configuration of the complex is shown by the block flow diagram of Figure 7.

The fertilizer complex will be located within the Eastern Seaboard Industrial Estate near the town of Mab Ta Pud (province of Rayong), as shown in Figure 8.

The layout of the complex is shown in more detail in Figure 9.
TABLE 1
THE IMPORTANCE OF VARIOUS FACTORS IN INFLUENCING FERTILIZER USE AND CROP YIELDS
(Example - Rice and Nitrogen Use)

<table>
<thead>
<tr>
<th>Country Group</th>
<th>Percent of Crop Area</th>
<th>Investment in Research &amp; Education</th>
<th>Fertilizer Availability</th>
<th>Price N/Rice</th>
<th>N Use (kg/ha)</th>
<th>Yield (t/ha)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>90</td>
<td>95</td>
<td>High</td>
<td>100</td>
<td>1</td>
<td>200</td>
</tr>
<tr>
<td>II</td>
<td>58</td>
<td>60</td>
<td>Medium</td>
<td>70</td>
<td>2</td>
<td>85</td>
</tr>
<tr>
<td>III</td>
<td>23</td>
<td>25</td>
<td>Low</td>
<td>25</td>
<td>3+</td>
<td>25</td>
</tr>
</tbody>
</table>

a. High-yielding variety.
b. Percent of fertilizer demand met by local production.
c. Price of nitrogen and rice at farm gate.

Source: IFDC reports.
### TABLE 2

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>N</td>
<td>677</td>
<td>162.2</td>
<td>265</td>
<td>4.56</td>
</tr>
<tr>
<td>P₂O₅</td>
<td>664</td>
<td>126.2</td>
<td>220</td>
<td>5.18</td>
</tr>
<tr>
<td>K₂O</td>
<td>200</td>
<td>35.6</td>
<td>60</td>
<td>4.86</td>
</tr>
</tbody>
</table>

### TABLE 3

<table>
<thead>
<tr>
<th></th>
<th>Projected Thai Demand in 1992</th>
<th>NFC Projected Sales</th>
<th>Thai Market Penetration by NFC (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>N</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fertilizer</td>
<td>265,000</td>
<td>200,000</td>
<td>75</td>
</tr>
<tr>
<td>Industrial</td>
<td>19,900</td>
<td>17,800</td>
<td>90</td>
</tr>
<tr>
<td>Total</td>
<td>284,900</td>
<td>217,800</td>
<td></td>
</tr>
<tr>
<td><strong>P₂O₅</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fertilizer</td>
<td>220,000</td>
<td>208,000</td>
<td>95</td>
</tr>
<tr>
<td>Industrial</td>
<td>27,000</td>
<td>13,500</td>
<td>50</td>
</tr>
<tr>
<td>Total</td>
<td>247,000</td>
<td>221,500</td>
<td></td>
</tr>
<tr>
<td><strong>K₂O</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fertilizer</td>
<td>60,000</td>
<td>44,000</td>
<td>75</td>
</tr>
<tr>
<td>Location</td>
<td>Process Units Included</td>
<td>Inclusion of ASEAN Commitments</td>
<td></td>
</tr>
<tr>
<td>----------</td>
<td>------------------------</td>
<td>--------------------------------</td>
<td></td>
</tr>
<tr>
<td>1. Rayong:</td>
<td>Ammonia; Urea; Sulfuric; Phosphoric; MAP-P; MAP-G</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>2. Rayong:</td>
<td>Ammonia; Urea; Sulfuric; MAP-P; MAP-G</td>
<td>ASEAN Urea</td>
<td></td>
</tr>
<tr>
<td>3. Rayong:</td>
<td>Ammonia; Urea; Sulfuric; Phosphoric; MAP-P; MAP-G</td>
<td>ASEAN Urea &amp; Soda Ash</td>
<td></td>
</tr>
<tr>
<td>4. Namphong:</td>
<td>Ammonia; Urea; Sulfuric; Phosphoric; MAP-P; MAP-G</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Rayong:</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>5. Namphong:</td>
<td>Ammonia; Urea; Sulfuric; phosphoric; MAP-P; MAP-G</td>
<td>ASEAN Urea &amp; Soda Ash</td>
<td></td>
</tr>
<tr>
<td>Rayong:</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>6. Rayong:</td>
<td>Ammonia; Urea; MAP-P; MAP-G</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>7. Namphong:</td>
<td>Ammonia; Urea; MAP-P; MAP-G</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Rayong:</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>8. Namphong:</td>
<td>Ammonia; Urea; MAP-P; MAP-G</td>
<td>ASEAN Urea &amp; and Soda Ash</td>
<td></td>
</tr>
<tr>
<td>Rayong:</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>9. Rayong:</td>
<td>Ammonia; Urea</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>10. Namphong:</td>
<td>Ammonia; Urea</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>11. Rayong:</td>
<td>Ammonia; Urea; Sulfuric; Phosphoric; MAP-P; MAP-G; Nitric; NP</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>12. Namphong:</td>
<td>Ammonia; Urea; Sulfuric; Phosphoric; MAP-P; MAP-G; Nitric; NP</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Rayong:</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>13. Rayong:</td>
<td>Ammonia; Urea; Sulfuric; Phosphoric; MAP-G; NPK-G</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>14. Namphong:</td>
<td>Ammonia; Urea; Sulfuric; Phosphoric; MAP-G; NPK-G</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Rayong:</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>
RAW MATERIAL

DOMESTIC IMPORT

NATURAL GAS

SULFUR

PHOSPHATE ROCK

AMMONIA SECTION 100 213.5

SULFURIC ACID SECTION 300 613.7

PHOSPHORIC ACID SECTION 400 221.5 (P2O5)

MAP POWDER 60.0

MAP/DAP GRANULATION 351.2

SECTION 500

AMMONIA (82/0/0)

PHOSPHORIC ACID (0/54/0)

MAP POWDER (11/54/0)

MAP GRANULES (11/54/0)

SODA ASH PLANT

INDUSTRY

INDUSTRY

TCCC

BULK BLENDER DISTRIBUTORS

BULK BLENDER DISTRIBUTORS

FIG. 3
FIG. 4
Project Implementation Schedule

MAJOR ACTIVITIES

1. Feasibility Study
2. Preparation of Bid Documents for EPC Contractor
3. Bid Preparation by EPC Contractor
4. Bids Evaluation, Negotiation and Contract Award
5. Detail Engineering
6. Procurement of Equipment and Materials by Contractor
7. Delivery of Equipment, etc.
8. Site Preparation
9. Plant Construction
10. Commissioning & Operation

*EPC: Engineering, Procurement and Construction.

FIG. 6
**National Fertilizer Complex Configuration**

1. **Natural Gas**
   - Ammonia Plant: 900 tons/day

2. **Sulphur**
   - Sulphuric Acid Plant: 2110 tons/day

3. **Phosphate Rocks**
   - Phosphoric Acid Plant: 720 tons/day

4. **Potash**
   - MAP Powder Plant & Prill Tower: 190 tons/day

- **Urea Synthesis Plant**: 1000 tons/day
- **Urea Granulation Plant**: 1000 tons/day
- **MAP/DAP/NP/NPK Preneutralizer & Granulation Plant**: 2800 tons/day

**Output Products**

- 15,800 tons/year Ammonia for Industrial Use
- 142,200 tons/year Urea Granules to Bulk Blenders & Distributors
- 62,800 tons/year MAP Granules
- 62,800 tons/year DAP Granules
- 670,000 tons/year NP/NPK Granules
- 60,000 tons/year MAP Powder
- 25,000 tons/year Phosphoric Acid for Industrial Use

**FIG. 7**
Lay out of the complex

FIG. 9
Thailand - United States Natural Gas Utilization Symposium & Field Trip
February 7 - 11, 1984

REVIEW OF PHOSPHATE, POTASH AND SODA ASH PRODUCTION PARAMETERS

PREPARED BY
G.R. JAMES AND BRIAN L. HUSON
James Chemical Engineering

Organized and Sponsored by
The Petroleum Authority of Thailand (PTT)
The United States Agency for International Development (USAID)
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- Markets
- Supply
- Processes

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- Supply
- Process

Soda Ash

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- Markets
- Supply
- Processes
INTRODUCTION

The theme of this symposium is utilization of natural gas and its immediate derivatives in the context of Thailand's current status as a producer of offshore gas now on the threshold of gas-based industrial development.

Industrial development, however, requires a picture of many interrelated inputs to discover the proper range of products. The value of natural gas use to produce ammonia and urea fertilizer for example is much enhanced by availability of phosphate and potash values. Urea nitrogenous fertilizer use in Thailand could be much affected by the impact of ammonium chloride a major by product in the favored way to make soda ash, the commodity chemical that can be regarded as an indicator of general industrial activity.

This presentation provides a brief coverage of these three products -- phosphate, potash and soda ash -- and thereby supplies some background to the other parts of this symposium referring specifically to natural gas applications. Gas development will be intimately tied up with, and to some extent dependent on, these possibly less glamorous products -- phosphate, potash and soda ash.
PHOSPHATE

"Phosphate" is a loosely applied generic name for phosphorus compounds. They are essential components of every living thing and are particularly important in the development of young tissue, both animal and vegetable. Minerally, phosphorus is obtained from phosphate rock in which it appears as a complex calcium phosphate. The classification of rock phosphate in terms of "bone phosphate of lime" underlines the importance of phosphate in bone, but for most commercial purposes the phosphate content is now measured in terms of the equivalent theoretical content of phosphorus pentoxide, P₂O₅.

Demand

Worldwide demand for "phosphate" requires the processing of nearly 150 million tonnes of phosphate rock per year. Of this over 90% moves to agricultural applications. In the USA, industrial uses only consume about 1.5 million tonnes per year of P₂O₅ or 4.5 million tonnes of rock, they include:

- Detergents and water treatment: 40-45%
- Food and pharmaceuticals: 15-20%
- Metal processing and treatment: 10-15%
- Chemical derivatives: 25-30%
- Fire prevention: 2-5%

In Thailand, phosphate demand as P₂O₅ increased rapidly from about 5000 tonnes per year in 1960 to over 50,000 tonnes per year in 1970. Since that time the growth rate has reduced somewhat but has maintained a rate sufficient to bring consumption to its current level of some 130,000 tonnes per year.
As above over 90% of rock production is eventually used in agricultural applications. This in spite of the fact that normal soils may contain 2000-3000 pounds per acre of P2O5. The problem is that only a tiny portion of the "phosphate" in the soil is in a soluble form which can be taken up by plants. Moreover, the "available" in soluble form applied as fertilizer reacts quickly with various components in the soil and is thereby rendered unavailable. A fertilizer crop seldom recovers more than 15-20% of the phosphorus applied. On the other hand, very little "phosphate" is carried away in solution from the ground, seldom more than one pound per year per acre. Quantities carried away in sediment can be much higher, perhaps 30-50 lbs/yr/acre. Removal of phosphorus by the plant growth varies widely with the type of plant. In grains, more phosphorus goes with the grain than in the straw.

Much research is oriented toward increasing the efficiency of phosphate utilization, not only by the plants to which it is applied as fertilizer but also in maximization of the transfer of phosphorus values inherent in the rock as mined into available "phosphate" in the fertilizer itself.

Supply "Where does it come from"

The world's phosphate rock resources are generally distributed as marine phosphorite material. Identified and hitherto undiscovered resources are estimated to contain billions of tons of "phosphate". Current production of rock worldwide amounts to nearly 150 million tonnes per year, the major suppliers are:

<table>
<thead>
<tr>
<th>% World Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>USA</td>
</tr>
<tr>
<td>USSR</td>
</tr>
<tr>
<td>Morocco</td>
</tr>
<tr>
<td>Tunisia</td>
</tr>
<tr>
<td>Jordan</td>
</tr>
<tr>
<td>Pacific Islands</td>
</tr>
<tr>
<td>Other</td>
</tr>
</tbody>
</table>
Process

In naturally-occurring phosphate rock, the phosphorus content is in a chemical state in which it is inaccessible to plants if applied directly. Although for some acid soils, pulverized rock can be applied and will provide phosphate nutrient, for most fertilizer use the chemical state of the phosphate component must be changed and the usual starting procedure is to treat the rock with sulfuric acid.

This treatment may either be directed to produce single or normal superphosphate (SSP), or to produce phosphoric acid. SSP is the original synthetic phosphate fertilizer some 20% P₂O₅. In many areas it has been superseded by other materials with higher nutrient content. Therefore allowing lower transport costs and applied costs per unit of nutrient. It still does have importance in areas suffering from sulfur deficiency (such as New Zealand). Phosphoric acid may be used either to convert more rock into triple superphosphate (TSP), or to react with ammonia and/or potash to produce multinutrient fertilizers such as monoammonium phosphate (MAP), diammonium phosphate (DAP) or compound fertilizers (NPKs).

In the production of phosphoric acid, most of the phosphate rock used is a sedimentary rock, (pebble phosphate), a major component of which is fluorapatite, chemically a mixed calcium fluoride/tricalcium phosphate. Treatment of this with sulfuric acid produces "wet process acid" (WPA). A highly simplistic summarization of the reaction is:

\[
\text{CaF}_2\left[\text{Ca}_3\left(\text{P}O_4\right)_2\right]_3 + 10 \text{H}_2\text{SO}_4 \\
6 \text{H}_3 \text{PO}_4 + 10\text{CaSO}_4 + \text{H}_2\text{F}_2
\]

There are several processes for manufacture of phosphoric acid, usually classified according to the crystalline form of the calcium sulfate byproduct, whether dihydrate (gypsum) or hemihydrate (plaster of Paris). The crystal form is important in that it controls the amount of phosphoric acid occluded with the precipitate and also the speed of filtration. The major processes licensed include:

- Dihydrate
  - Prayon, Rhone-Poulenc, Dorrco, Nissan (D-process) Gulf Design, et
- Hemihydrate
  - Fisons (H1 process), Occidental
  - Central - Prayon
  - Nippon Kokan, Nissan (H process) Mitsubishi Chemical
- Dihemihydrate
- Modified hemihydrate
  - Nissan (C-process) and Fisons (HDH process)
In the dihydrate process: phosphate rock is treated with sulfuric acid and partially recycled phosphoric acid at a temperature of 70 - 80 degrees C, which is the stable range for dihydrate. The resultant slurry is filtered to obtain phosphoric acid (at 26-30% concentration) and gypsum.

Because of the simplicity of the process, the plant construction cost is relatively low. However appreciable amounts of acid are lost in the precipitated sulfate and the recovery rate of P205 from phosphate rock is as low as 90-95%. Furthermore as the P205 content of the by-product gypsum is rather high, there can be problems in utilization or disposal.

The basic dihydrate process is offered by several licensors, whose knowhow differs mainly in the engineering design, such as type of digester (multi-tank, square tank, round tank, etc.), filter type (belt, tilting pan, etc.), cooling procedures, etc. Each has both merits and demerits, and appraisal/selection depends greatly on the particular characteristics of a specific situation/location.

In the hemihydrate process, phosphate rock is first decomposed with sulfuric and phosphoric acids at a temperature of 90-100 degrees C, the stable range for hemihydrate, which is then filtered off to obtain product phosphoric acid. Crystals of calcium sulfate hemihydrate are difficult to filter and the process requires larger filtration area than that for the dihydrate process.

The process yields phosphoric acid of higher concentration. Strengths of 40-50% are obtainable, but as with the dihydrate process the acid recovery rate is as low as 90-94% and by-product calcium sulfate is also inadequate for utilization.

As for actual facilities, Fisons Co. has licensed one plant and Occidental Chemical Co. owns an operating unit.

The di-hemihydrate process starts like the dihydrate route, in that phosphate rock is treated with sulfuric acid at a temperature of 70-80 degrees C in temperature, the dihydrate's stability range. The resultant slurry is separated by centrifuge or other method into gypsum and product phosphoric acid of about 30% concentration. The gypsum precipitate is again treated with sulfuric acid this time at the higher temperatures of the hemihydrate stability range. The calcium sulfate hemihydrate formed is filtered out, and liquid is recycled for phosphate rock decomposition.

By this method P205 recovery is as high as 97-98%. Furthermore the calcium sulfate is obtained by immediate drying in a form which is more acceptable for commercial applications. If all of the sulfate is not utilized immediately however, difficulties may arise in disposal, as the material hardens rapidly.
Some plants using the Central Prayon process have been established in Japan and other countries.

The hemidihydrate was developed in Japan. Phosphate rock is first decomposed with phosphoric and sulfuric acids at a temperature of 90 – 100 degrees C, which is the range of stability for calcium sulphate hemihydrate. The resultant slurry is matured at a temperature of 50 – 65 degrees C and the hemihydrate recrystallized into calcium sulphate dihydrate (gypsum).

This process is more complicated than the simple dihydrate process, and requires a slightly higher construction investment. However, the recovery rate for P2O5 from the rock is as high as 97.5 – 98.5% Furthermore, less P2O5 is contained in the by-product gypsum which permits its use for gypsum board manufacture.

About 30 plants have been constructed all over the world with maximum production capacity up to 700 tonnes P2O5/day.

Modified hemi-dihydrate process: modifications of the hemihydrate process improved the low recovery of P2O5 and reduced the difficult problems experienced with utilization of by-product gypsum. The new process follows the same route as the hemihydrate process up to the filtration of the crystallized hemihydrate and production of 40-50% P2O5 phosphoric acid. The modified process treats the calcium sulphate hemihydrate separated from the slurry with acid at a temperature condition of 50 – 60 degrees C, recrystallizing it to the dihydrate. This is then filtered off, yielding a better quality by-product gypsum and high overall P2O5 recovery rate.

This process uses two filters, requiring higher investment costs than those for the other processes, unless the high concentration of the acid produced obviates the need for further concentration.

Plants using the Fisons HDH-process are operating in Europe, and plants using the Nissan Chemical C-process are now running in Japan.

A simple tabulation illustrating the respective characteristics of the various processes is given in the attached table. (See Fig. 4)
FIGURE 4 CHARACTERISTICS OF
PHOSPHORIC ACID PROCESSES

<table>
<thead>
<tr>
<th>Process Type</th>
<th>Licensor</th>
<th>P2O5 Recovery %</th>
<th>Relative Investment Cost</th>
<th>Acid Concentration % P2O5</th>
<th>Gypsum Grade</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dihydrate</td>
<td>Prayon, Dorrco Nissan (D)</td>
<td>90 - 95</td>
<td>100</td>
<td>30</td>
<td>Average</td>
</tr>
<tr>
<td></td>
<td>Rhone Poulenc</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hemihydrate</td>
<td>Fisons (HH) Occidental</td>
<td>90 - 94</td>
<td>105</td>
<td>40 - 50</td>
<td>Poor</td>
</tr>
<tr>
<td>Dihemihydrate</td>
<td>Central-Prayon</td>
<td>97 - 98</td>
<td>115</td>
<td>30</td>
<td>Good</td>
</tr>
<tr>
<td>Hemidihydrate</td>
<td>Nippon Kokan Mitsubishi</td>
<td>97 - 99</td>
<td>110</td>
<td>30</td>
<td>Good</td>
</tr>
<tr>
<td>Modified Hemidihydrate</td>
<td>Fisons (HDH) Nisson (C)</td>
<td>97 - 99</td>
<td>125</td>
<td>40 - 50</td>
<td>Good</td>
</tr>
</tbody>
</table>
In Thailand there are some deposits of phosphate rock, but to meet commercial demands essentially all the phosphorus value for now is imported. Since the country also lacks adequate commercial sources of sulfur which could be used to produce the sulfuric acid normally used to render the phosphate "available," local facilities to treat imported rock would also have to import sulfur or sulfuric acid. In current market conditions there is some doubt whether such facilities could compete economically with imports of the phosphate in available form either as phosphoric acid or derivatives. In any case, any consideration of production of phosphoric acid would presumably lean heavily toward the sophisticated high-yield process so as to minimize the wastage of P205 content suffered in the simple dihydrate or hemihydrate processes.

There are alternate routes for the recovery of phosphate values from the naturally occurring rock. Acids other than sulfuric can be used. Nitric acid, for instance, yields directly nitrophosphates which have important values as double nutrient NP fertilizers.

An entirely different approach, particularly valuable with lower-grade rock, treats the rock at high temperature with carbon (coke) and silica (gravel) to produce elemental phosphorus. This is then burnt to the pentoxide (P205) which on dissolving in water can produce high-grade concentrated acid directly without the evaporation steps required with wet process acid. Historically the high temperature required in the first step has been produced by an electric arc furnace, but a new modification of the old "blast furnace" route, developed by Occidental Chemical, uses a rotary kiln that could have significant advantages. The route via phosphorus avoids the requirement for sulfur, and can use lower-grade rock, in many cases without the beneficiation step and resultant effective P205 loss. The kiln route has significant economic potential as it avoids the high power requirement of the furnace acid process, and therefore can be particularly interesting in agricultural situations like that of Thailand where local supplies of rock are of relatively poor quality and/or quantity, and there are no local sources of sulfur to support phosphate fertilizer production by the wet acid route.
Potash

Markets

Potash as with “Phosphate” is loosely used as a general name for materials containing potassium. The activity of the materials is usually measured in terms of the (equivalent) content of potassium oxide, K2O.

Potassium is essential to a variety of crop growth processes. It is critical in stem plants to prevent wilting. Unlike nitrogen and phosphorus, much of which are removed with the crop, most of the potassium in the plant is contained in the normally unwanted portions of the plant. Consequently a high proportion of the potassium remains in the field at harvest time unless the collection procedures remove the whole plant. Potash therefore tends to remain in the soil. However unlike phosphate it is prone to be removed from the growing area by leaching. As with nitrogen and phosphate there is no substitute for its use as a major plant nutrient.

Worldwide demand for potash amounts to about 30 million tonnes per year, of which over 90% of the total is used as a source of fertilizer nutrient. Industrial uses of potash include:

10% as phosphate, mostly as builder in detergent formulations
70% as hydroxide, mainly as intermediate to other potassium derivatives, as permanganate, bromate and iodate in pharmaceuticals, food additive, etc.
5% as carbonate, in manufacture of special glasses

In Thailand potash demand has developed rapidly from 1-2000 tones/year (K2O basis) in 1960 to its current level of 30-40,000 tonnes/year.

Supply

These consumptions compare with an estimated global availability of a total of about 140 billion tonnes, about half of which are located in Saskatchewan, Canada. In some places potash is found naturally in its concentrated, soluble form (sylvite, KCl) which can be used directly for fertilizer applications. In most areas, however, the potassium-bearing mineral is associated with other metallic elements such as sodium, magnesium or calcium.
Ore types of major importance include:

- **Sylvinite** - Mixed sylvite and halite (NaCl)
- **Carnallite** - Potassium magnesium chloride
  \[ \text{KCl}, \text{MgCl}_2 \times 6\text{H}_2\text{O} \]
- **Kainite** - \[ \text{KCl}, \text{MgSO}_4 \times 3\text{H}_2\text{O} \]
- **Langbeinit** - \[ \text{K}_2\text{SO}_4 \times 2\text{MgSO}_4 \]

Very large resources, about ten billion tonnes, exist in Thailand. However these are mostly carnallite, a mixed potassium/magnesium chloride.

Major ore reserves are in:

<table>
<thead>
<tr>
<th>Country</th>
<th>Estimated % of World Total</th>
<th>Major Ores Present</th>
</tr>
</thead>
<tbody>
<tr>
<td>Canada</td>
<td>49 %</td>
<td>Halite, Carnallite</td>
</tr>
<tr>
<td>USA</td>
<td>4 %</td>
<td>Halite, Sylvite, Carnallite, Sylvinite, langbeinit, etc.</td>
</tr>
<tr>
<td>Germany, France</td>
<td>6 %</td>
<td>Halite, Sylvite, Carnallite, sylvinite, etc.</td>
</tr>
<tr>
<td>USSR</td>
<td>29 %</td>
<td>Sylvinit, langbeinit, Kainite, etc.</td>
</tr>
<tr>
<td>Thailand</td>
<td>7 %</td>
<td>Sylvinit, Carnallite</td>
</tr>
</tbody>
</table>
World supplies are at present produced geographically as follows:

- Canada: 28%
- Germany: 9%
- USA: 8%
- France: 7%
- USSR & allies: 42%
- Other: 4%

As already mentioned, over 90% of total potash is used as a source of fertilizer nutrient, and the chloride, otherwise known as muriate, KCl, has about the same dominance on the supply side.

Normally KCl at 95-96% purity (60-61% K₂O) is suitable for fertilizer use. Impurities are generally sodium and magnesium chlorides. The material for fertilizer is available in three major grades by size:

- **Standard**: 75% - 20 mesh, 95% + 65 mesh
- **Coarse**: 79% - 14 mesh, 94% + 28 mesh
- **Granular**: 96% - 6 mesh, 98% + 20 mesh

For chemical purposes potash is usually available in powder form at 99.95% purity.

**Process**

Selection of a process for production of marketable potash depends on the nature of the raw material.

Production of potash, usually as KCl, from natural deposits requires primarily its separation from the unwanted components of the ore. This involves both mechanical separation, usually flotation, to gather the potash-bearing material from the run-of-mine, followed by chemical separation, usually by crystallization procedures.
Simple physical/mechanical separation usually involves crushing and/or grinding of the ore which is then suspended in a brine and passed to flotation cells.

In some locations the difference in gravity of the potassium chloride is sufficient to achieve a separation of potash product of 50-51% K2O content (after de-brine-ing) adequate for many agricultural purposes.

In other locations the crushed ground ore (for instance, Sylvinite is subjected to soap-flotation which floats off the sodium chloride and depresses the potash. In Canada the ore is mixed carnallite/sylvinite, which is crushed and ground and then leached with brine. The brine dissolves out the magnesium chloride (water is added to keep its concentration below saturation levels), and subsequent flotation separates the sodium from the potassium chloride.

Purification of the potassium chloride by crystallization usually relies on the fact that sodium chloride is less soluble in hot than in cold saturated potassium chloride solution. When a hot solution saturated with both chlorides is cooled, potassium chloride crystals separate out, pure except for the small quantities of entrained saturated solution, which are removed by washing to leave pure potassium chloride product.

Investment and operating costs and requirements obviously depend on the nature of the input material. Utility demands for processing one tonne of sylvinite ore have been given as:

- Water: 150-200 cu m
- Steam: 1-1.5 tonnes
- Electric power: 50-60 KWH
INTRO

Soda ash, sodium carbonate, is a basic industrial commodity, a major input to the glass, pulp and paper, and soap and detergent industries and the chemical industry generally. In the USA current domestic demand of 6-7 million tonnes per year is made up as follows:

<table>
<thead>
<tr>
<th>Industry</th>
<th>Demand Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>Glass</td>
<td>55%</td>
</tr>
<tr>
<td>Chemicals</td>
<td>20%</td>
</tr>
<tr>
<td>Pulp &amp; Paper</td>
<td>5%</td>
</tr>
<tr>
<td>Soap &amp; Detergents</td>
<td>5-10%</td>
</tr>
</tbody>
</table>

Exports from the USA amount to about 1 million tonnes per year. Over-optimistic forecast of demand growth in the 1970's led to considerable capacity construction in the USA based on natural trona. To fill this capacity there has been considerable development of exports (from the USA) which are now exerting very keen competition for synthetic product worldwide.

Demand of Soda Ash

The world market amounts to nearly 30 million tonnes per year, broken down approximately as follows:

<table>
<thead>
<tr>
<th>Region</th>
<th>Demand Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>N. America</td>
<td>25%</td>
</tr>
<tr>
<td>W. Europe</td>
<td>25%</td>
</tr>
<tr>
<td>E. Europe</td>
<td>30%</td>
</tr>
<tr>
<td>Asia/Pacific</td>
<td>15%</td>
</tr>
<tr>
<td>Other</td>
<td>5%</td>
</tr>
</tbody>
</table>

Supply

Naturally occurring deposits of sodium carbonate have been identified in over 60 locations globally, much of it as trona, a mixed carbonate/bicarbonate, of which the largest deposit is in Wyoming, USA, containing over 100 billion tons. Another big bed is at Lake Magadi in Kenya.

In spite of this natural availability, soda ash, except for the USA and some small quantities for certain African areas, is obtained commercially by synthesis from sodium chloride.

Synthesis

The original synthesis process, developed by Leblanc in the 1770's, roasted salt cake, carbon and limestone in a rotary furnace; leaching the product with water produced "black ash" from which sodium carbonate was extracted by concentration and crystallization. The Leblanc process suffered from multiple problems, notably in product purity, high labor and energy costs, and serious environmental impact. It was vulnerable to competition from the Solvay process, which became commercial in the mid 1800's, and fairly rapidly superseded the Leblanc route.
The Solvay process combines several interlocked production steps:

Limestone plus coke in a kiln produces lime and carbon dioxide.

Ammonia in solution plus carbon dioxide yields ammonium bicarbonate.

Salt solution reacts with the ammonium bicarbonate to produce ammonium chloride solution and sodium bicarbonate crystals which after filtration and calcination yield soda ash.

Ammonium chloride treated with lime regenerates the ammonia solution and yields byproduct calcium chloride.

The Solvay process yields high purity product and consumes a minimum of ammonia (which 100 years ago was a high priced reagent). However the facilities required involve high investment cost and (still) relatively high energy consumption. In the USA Solvay plants have been squeezed out by units producing "natural" ash from mineral trona, whereas overseas the Asahi process took over, requiring significantly lower unit investments and using lower cost ammonia to produce ammonium chloride byproduct, a fertilizer, instead of calcium chloride.

The Asahi process is basically a modification of the conventional Solvay process, and inherits some of its disadvantages. Energy consumption is still high, as is the labor requirement; furthermore ammonium chloride is not universally acceptable as a nitrogenous fertilizer as application of the chloride ion can have unfavorable agronomic results. A new Asahi process has been developed, in some respects reverting to the Solvay route—in that limestone and coke are included in the new materials, and calcium chloride in the products.

Relative consumptions of the major processes are summarized in the following table: (see fig. 10)
FIGURE 10 - PROCESS COMPARISON FOR SODA ASH MANUFACTURE

<table>
<thead>
<tr>
<th>Input Material</th>
<th>Relative Consumption per ton of Soda Ash</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Solvay Process</td>
</tr>
<tr>
<td>Salt</td>
<td>100 %</td>
</tr>
<tr>
<td>Limestone</td>
<td>100 %</td>
</tr>
<tr>
<td>Coke</td>
<td>100 %</td>
</tr>
<tr>
<td>Ammonia</td>
<td>1 %</td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>15 %</td>
</tr>
<tr>
<td>Fuel</td>
<td>100 %</td>
</tr>
</tbody>
</table>
The Asahi processes reduction in salt consumption is significant, as the usage in a Solvay facility at 1.5-1.6 tons per ton of ash, represents only about 70% utilization of the sodium content of the feed. The original Asahi process dispensed with the lime kiln depending on an associated ammonia plant for both ammonia and carbon dioxide inputs.

Fuel consumption has shown steady improvement since the 1940's, but the original Asahi process is hardly comparable with the Solvay and New Asahi routes as it avoids fuel expenditure in the lime kiln. Current fuel demand in the last remaining Solvay plant in the USA amounts to 17-13 MM BTU/tonne of soda ash produced (using coal as a fuel rather than fuel oil). This compares with 8-8.5 MM BTU/tonne for ash production from trona. Natural material is also the advantage of significantly lower residual sodium chloride content, which renders it preferable in glass manufacture, where salt forms unwelcome deposits and increased fuel consumption.
Soda Ash is available to commerce as light ash and dense ash.

Light ash is the product if solid bicarbonate is heated at about 150 - 170 degrees centigrade, to form anhydrous sodium carbonate, carbon dioxide, and water vapor. Density is about 1/2 tonne per cubic meter. It is the cheaper form of ash, porous, absorbent, with high surface area, but does suffer dust problems.

Dense ash is usually produced by recrystallizing the light ash to sodium carbonate monohydrate which on heating to 135-145 degree centigrade loses the water of crystallization. The dense ash is about double the gravity of the light ash, and is manufactured primarily for the glass industry, which consumes about half the total production of ash. Production of the dense form adds about 1 MM BTU/tonne to the energy cost of the ash.

The overcapacity in the USA, combined with its low energy consumption, is expected to increase the US's dominance of the global market, and represents considerable disincentive to construction of further capacity worldwide. However, an interesting new development by Akzo Zolat Chemie of a chemical route to produce soda ash and ethylene dichloride from salt and ethylene could introduce a new route to vinyl chloride. This would avoid expensive electrolysis installations, and could be particularly valuable in some of the smaller national markets that cannot economically compete in PVC production with the world scale plants that now dominate that market.

This presentation attempts to give you some indication of the major items of interest in the industrial production of Phosphate Potash and Soda Ash, three indispensable components in a program for industrial development. This coverage, only hits the high points of technology economics. It other information may be of importance to you any questions you may have now or your specific written enquiries will be dealt with as promptly as possible.

The major effort in preparation of this paper was made by any colleague, Brian Huson. His efforts have made this contribution possible. The efforts of our associates, Regional Engineering Consultants Co., Ltd., have also been valuable in assembling and editing the works.
MAKE AMMONIA WITH LESS ENERGY

by

J.R. LeBlanc

The M. W. Kellogg Company

to be presented at

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ABSTRACT

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Ammonia, one of the largest volume industrial chemicals, is absolutely essential to world food production. The manufacturing process used to produce ammonia is a very energy intensive operation. In recent years, much attention has been given to reducing the energy consumption in making ammonia. In this paper, both new plants and retrofitting existing ammonia plants for increased energy efficiency will be discussed.
Introduction

Ammonia is, world-wide, the industrial chemical manufactured in largest volume. Absolutely essential to world food production, it is used as a fertilizer directly as well as in the form of urea, nitrates, phosphates and fertilizer solutions. That this importance is generally recognized is reflected by the fact that becoming self sufficient in ammonia production is a goal in the industrialization programs for many developing nations.

A critical factor in ammonia manufacture is its very significant energy consumption. Particularly in some older plants, the cost of energy can represent 80-90% of the selling price of ammonia. In many future ammonia plants, energy will still represent more than 50% of the product ammonia selling price. Thus, the critical importance of ammonia to world civilization, its high energy consumption requirement, and the diminishing supply of inexpensive sources of energy combine to force a critical evaluation of the ammonia process, particularly with respect to reducing its energy input.
Background

Historically, Kellogg's efforts in this field date back to 1943. From that time to the present, a number of significant improvements have been made. As a result of this expertise, Kellogg plants account for over 50% of the world's ammonia capacity added since 1965.

One of the major reasons for this past success has been the proven ability to reduce energy consumption over these forty years. Table 1 reflects the history of energy consumption in the Kellogg ammonia process from its beginning in 1943 to our latest energy efficient design which was successfully started up in the spring of last year. As we see from this table, the Kellogg ammonia process is operating with an energy consumption of less than 25 MM BTU(LHV)/ST.

This latest significant achievement of reducing energy consumption in the Kellogg ammonia process was preceded by a dedicated and deliberate program. Such an endeavor received the highest management attention. To initiate the work, an objective was set by the Technical Steering Committee: "Make a Substantial Improvement in the Energy Consumption for the Kellogg Ammonia Process. Rely Heavily on our Past Successful Commercial Experience". This objective initiated work which generally included: background review, process design, engineering design, research and development testing, and field unit operation; in essence, all technical disciplines available to Kellogg, and in certain areas, outside consultants were used to bring the effort to fruition. This work, specifically aimed at new plant design, was also used in large measure to address retrofitting existing plants.
In embarking on such a program, it is often wise to consider a theoretical analysis to understand the potential energy savings available. Table 2 reflects such an analysis. Here we see from thermodynamic data that, if it were possible to build an ideal process to produce ammonia from the steam reforming of methane, the theoretical energy requirement of the feed is all that is necessary -- 17.9 MM BTU(LHV)/ST. In actual operation, the net feed (after purge gas credit) is very close to this value. However, the analysis also shows that we should obtain both a heat and work output from the ideal process. In actual operation, we input both heat and work in the manufacturing process. Although this is a purely theoretical treatment, it serves to show that there is substantial room for improvement.

The second area for initial review is the energy consumption of a typical conventional plant in normal operation. Table 3 reflects such an overview. We see that the net feed rate approaches that of the theoretical value. The Law of Stoichiometry applies here, and hence, no improvement is possible. However, a considerable amount of fuel is used, even though the previous theoretical analysis reflected an energy output.

Table 4 shows major energy losses associated with operating the plant. Such an analysis can allow you to focus attention on areas of the plant which use large amounts of energy. We find a large amount of energy loss through
surface condensers. Surface condensers are associated with steam turbine drives on pumps and compressors. One of the largest energy consumers in the process is that of the carbon dioxide removal system. Large amounts of thermal energy are used to regenerate the absorbing solution. Small inefficient turbines used as mechanical drives are also energy consumers. In addition, the thermal energy loss in the furnace stack gases can account for about 14% of the plant fuel usage.

New Plant Design

From this type of review the main strategies employed in the new plant design effort are listed as follows:

- Reduce Power Consumption
- Improve Process Heat Recovery
- Reduce CO₂ Removal Energy Consumption
- Improve Power Cycle Efficiency
- Reduce Stack Gas Losses

As I am sure you will appreciate, there was considerable work -- several years in time -- between this first overview analysis and today's design. Three major efforts were undertaken, much of which ran simultaneously: research and development; engineering development and design; and field unit design and operation. As a result, Kellogg has the broad technology base needed to meet site specific project requirements world wide.
For today's projects where the cost of energy is a significant factor, Kellogg's design has a demonstrated natural gas consumption of less than 25 MM BTU(LHV)/ST.

Figure 1 reflects a block flow diagram typical of the energy efficient plant in operation today. The process sequence consists of converting desulfurized hydrocarbon feed at about 500 psig to produce raw synthesis gas in a primary and secondary reforming operation. Air is introduced into the secondary reformer in an amount equal to the nitrogen required for ammonia synthesis. Raw gas then flows to the two stage CO shift conversion facility for further production of hydrogen using a combination of high and low temperature shift catalysts. This design selection permits residual CO in the shifted gas to be reduced to 0.5% and lower. Following CO conversion, the gas is treated with a regenerative solution for CO₂ removal after which it undergoes methanation for conversion of residual carbon oxides to CH₄. The CH₄ is ultimately removed, along with argon from the air, in a purge from the synthesis loop. Purified synthesis gas is then compressed and mixed with the recycle gas from the synthesis loop. The combined flow, after additional compression, is delivered to the synthesis loop at about 2000-3000 psig for conversion to ammonia. Mechanical refrigeration, using ammonia as a refrigerant, is used to condense the product ammonia from the converter effluent. Purge gas recovery can be used to recycle hydrogen in the purge gas back to the synthesis loop.
In addition to the new efficient process design, new equipment designs were established to accommodate the new process. Table 5 shows major process features of the technology where a change relative to past designs was made. Within this technology, there is also the flexibility to adapt to project particulars.

Although energy efficiency provided the impetus for this effort, of equal importance was plant operability and reliability. Hence, the design that developed was predicated on being at least as reliable as Kellogg's past plants.

Table 6 presents a typical comparison between the conventional plant and the new energy efficient design. We see that the plot areas are the same, with the same number of operators being required. This is a good indication that the complexity of the new design is no more than that of the more conventional one. As an indication of what has been achieved in reducing power requirements, it is seen that the major compressor horsepower requirements of the new plant is only about 77% of the conventional design. In reducing energy consumption, some additional side benefits are realized. One example is reflected in the relative cooling water circulation requirement. In the more energy efficient design, less heat is thrown away to the cooling water system with the result being that the circulation rate of the new design is only about 63% of the conventional design. The bottom figures comparing energy consumption reflects the measure of success achieved. From actual operation of the Sherritt Gordon Mines 1100 ST/D ammonia plant in Fort Saskatchewan, Alberta, Canada, the energy consumption achieved was less than 25 MM BTU(LHV)/ST.
These energy consumption values include both feed and fuel. In either plant the feed values are the same -- about 18 MM BTU(LHV)/ST. Therefore, a more accurate assessment would be to compare fuel values. For the conventional plant, the fuel consumption is about 13-15 MM BTU(LHV)/ST. The operation at Sherritt Gordon reflected a fuel consumption of less than 7 MM Btu(LHV)/ST. Therefore, comparing just fuel values, the new design uses only about 50% of the fuel of the conventional plant.

Reviewing Table 7, for the given economic format, the savings in operating cost for the reduced energy plant is about $28/ST, or about $10,000,000 per year. With this type of format the cost savings is very significant.

Retrofitting Existing Plants

Exactly the same principles described previously for the new plant can be applied for existing facilities. However, implementation in an existing plant is generally much more difficult than in a new design.

Unlike designing a new energy efficient ammonia plant, modifying an existing plant can be more complicated. In addition to capital cost, payout and energy savings, careful consideration must be given to dismantling/removing of existing equipment, installation of tie-ins, plant downtime and loss of production.
Kellogg's experience with such ammonia plant modifications dates back to the late 1950's. From that time to present about 35 projects have been undertaken. Many of these projects ended with the engineering effort, but well over one-third went ahead to completion.

In recent years, Kellogg has studied the application of a wide variety of improvement features. One such effort completed for a nominal 1000 ST/D ammonia plant in the United States included the following features:

- Combustion Air Preheat
- Increase Steam Superheat Temperature
- Improved CO₂ Removal System
- Molecular Sieve Purification
- Additional Ammonia Synthesis Catalyst

The results showed that a savings of about 4 MM BTU(LHV)/ST could be achieved with the modification.

In order for such an effort to reach a successful completion, a proper execution plan is essential. The proposed means of implementing such a project would consist of four basic phases:

- Establishment of Project Scope and Collection of Data
- Basic Design/Planning
- Detailed Engineering/Procurement
- Construction/Startup
An early definition of project scope and a firm design basis is necessary in meeting a schedule and budget. Retrofits can be fraught with unknowns and therefore, an early well defined project scope will allow more flexibility when the unknowns crop up. Firming up the design basis will normally require that time be spent at the site gathering basic data. Data collected during such a visit would include the following:

1. Base plant operating data; point to point flows, compositions, pressures and temperatures
2. Base plant process flow diagrams
3. P&ID's (as current as available) - these should be field checked for accuracy
4. Piping drawings if different from original design
5. Plot plans reflecting any modifications that may have been implemented since the plant was originally commissioned

Once all data has been collected, it is possible to establish a basis for the current operation. This is extremely important because it results in an analytical calculation of the existing operation, which then becomes a basis for recalculating the modified operation. Basic design may proceed at this point. Material developed during this basic design/planning phase will include:

1. Process flow diagrams/description
2. Piping and instrument diagrams
3. Engineered data sheets (for new and modified existing equipment)
4. Preliminary plot plan
5. Feed and utility summary
6. Cost estimate
This is a milestone point, as both benefits (energy savings) and costs are defined. Thus an evaluation can be made to go ahead with the project.

At the conclusion of the basic design/planning phase, client reviews are held in order that any changes or modifications to the documents be made before proceeding with detailed engineering. The detailed engineering phase of the work is carried out on a task force basis utilizing teams of personnel dedicated to the project.

Construction begins before the completion of detailed engineering; therefore, the design personnel assigned to the project can assist with solving any special problems that may have arisen in the field. It is anticipated that the majority of construction work can be completed while the plant is onstream, thus minimizing expensive downtime. Certain final tie-ins will, of necessity, be made during a shut-down period before starting up the improved plant.

With such a proper plan, retrofit programs can be very successful.

Summary

Fueled by increasing energy costs, M. W. Kellogg has reduced the energy consumption in the manufacture of ammonia. This technology is being used in new plant designs, and has application in retrofitting existing plants.
### Table 1

#### History of Kellogg Ammonia Process:

**Energy Consumption**

<table>
<thead>
<tr>
<th>Year</th>
<th>Energy Usage, LHV</th>
</tr>
</thead>
<tbody>
<tr>
<td>1943 - 1965</td>
<td>38 - 40 MM BTU/ST</td>
</tr>
<tr>
<td>1966 - 1972</td>
<td>32 - 34 MM BTU/ST</td>
</tr>
<tr>
<td>1973 - 1983</td>
<td>31 - 32 MM BTU/ST</td>
</tr>
<tr>
<td>1983</td>
<td>Less than 25 MM BTU/ST</td>
</tr>
</tbody>
</table>
TABLE 2
ENERGY CONSUMPTION THERMODYNAMICS

\[ \text{CH}_4 + 1.3974 \text{ H}_2\text{O} + 0.3013 \text{ O}_2 + 1.132 \text{ N}_2 \rightarrow \text{CO}_2 + 2.264 \text{ NH}_3 \]
\[ \Delta H^0 \text{ 40°C} = 25,680 \text{ BTU/MOL CH}_4 \]
\[ \Delta H^0 \text{ 40°C} = 36,190 \text{ BTU/MOL CH}_4 \]

<table>
<thead>
<tr>
<th>Theoretical Feed Consumption</th>
<th>17.9 MM BTU(LHV)/ST</th>
</tr>
</thead>
<tbody>
<tr>
<td>Theoretical Heat Output</td>
<td>0.5 MM BTU(LHV)/ST</td>
</tr>
<tr>
<td>Actual Heat Input</td>
<td>14-16 MM BTU(LHV)/ST</td>
</tr>
<tr>
<td>Theoretical Work Output</td>
<td>500 HP HR/ST</td>
</tr>
<tr>
<td>Actual Work Input</td>
<td>1000 HP HR/ST</td>
</tr>
</tbody>
</table>
**TABLE 3**

OVERVIEW OF CONVENTIONAL PLANT ENERGY USAGE

**NORMAL OPERATION**

<table>
<thead>
<tr>
<th>Description</th>
<th>MM BTU(LHV)/ST</th>
</tr>
</thead>
<tbody>
<tr>
<td>FEED (After Purge Credit)</td>
<td>18.1</td>
</tr>
<tr>
<td>FUEL</td>
<td>15.3</td>
</tr>
<tr>
<td>TOTAL</td>
<td>33.5</td>
</tr>
</tbody>
</table>
### TABLE 4

**MAJOR ENERGY LOSSES**

**NORMAL OPERATION**

<table>
<thead>
<tr>
<th>Process</th>
<th>MM BTU/ST</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface Condensers</td>
<td>5.6</td>
</tr>
<tr>
<td>Carbon Dioxide Removal</td>
<td>3.2</td>
</tr>
<tr>
<td>Small Condensing Mechanical Drive Turbines</td>
<td>1.1</td>
</tr>
<tr>
<td>Furnace Stack Gas</td>
<td>2.1</td>
</tr>
</tbody>
</table>
### TABLE 5

**MAJOR PROCESS FEATURES**

- Revised Reforming Conditions and Heat Recovery
- Reduced Energy CO₂ Removal System
- Makeup Gas Drying
- Horizontal Ammonia Converter
- More Efficient Refrigeration System
- Purge Gas Recovery
- More Efficient Energy Systems
- Flexibility to Adapt to Project Particulars
### TABLE 6
**COMPARATIVE ANALYSIS *\**

**CONVENTIONAL VS REDUCED ENERGY AMMONIA PLANTS**

<table>
<thead>
<tr>
<th>Capacity</th>
<th>CONVENTIONAL 1100 STPD</th>
<th>REDUCED ENERGY 1100 STPD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area Required (Battery Limits)</td>
<td>250 Ft. x 400 Ft.</td>
<td>250 Ft. x 400 Ft.</td>
</tr>
<tr>
<td>Operators (Battery Limits)</td>
<td>5 - 6</td>
<td>5 - 6</td>
</tr>
<tr>
<td>Compressor Power</td>
<td>44,300 BHP</td>
<td>34,200 BHP</td>
</tr>
<tr>
<td>Cooling Water Circulation</td>
<td>43,000 gpm</td>
<td>27,000 gpm</td>
</tr>
<tr>
<td>Energy Consumption</td>
<td>31-33 MMBTU(LHV)/ST</td>
<td>Flexible Actual Operation of less than 25 MM BTU(LHV)/ST</td>
</tr>
</tbody>
</table>

*Typical Installations*
<table>
<thead>
<tr>
<th>Raw Material, Utilities</th>
<th>CONVENTIONAL $/ST</th>
<th>REDUCED ENERGY $/ST</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>132.16</td>
<td>104.11</td>
</tr>
<tr>
<td>Natural Gas, $4/MMBTU</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water, $0.75/MGal</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Power, $0.06/KWh</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Catalyst/Chemicals      | 1.89               | 1.85                 |

| Operating Labor/Supervision | 0.26               | 0.26                 |

| Maintenance (2)           | 5.50               | 5.50                 |

| Total Operating Cost      | 139.81             | 111.72               |

| △ Operating Cost          | --                 | 28.09 $/ST           |
|                          |                    | 10,000,000 $/Year    |

(1) Typical Installations
(2) Historical Data
FIGURE 1
AMMONIA PROCESS
BLOCK FLOW DIAGRAM

AIR COMPRESSION

STEAM

DESULFUNIZER

PRIMARY REFORMER

SECONDARY REFORMER

STEAM

WASTE HEAT RECOVERY

HIGH & LOW TEMP SHIFT

WASTE HEAT RECOVERY

WASTE HEAT RECOVERY

NATURAL GAS OR NAPHTHA

FUEL

CO2 REMOVAL

METHANATION

MOLECULAR SIEVE DRIERS

SYN GAS COMPRESSION

SYN GAS COMPRESSION

SYN G bağlı RECOVERY

PURGE GAS RECOVERY

WASTE HEAT RECOVERY

SYNTHESIS LOOP

REFRIGERATION

AMMONIA PRODUCT
FIRING WITH GAS IN CEMENT KILNS

BY

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LADIES AND GENTLEMEN:

SLIDE #1

I consider it a distinct privilege to address this elite group of representatives of the Thailand's Industry.

I realize that the prime purpose of this seminar relates to the use of Thailand's natural gas in Industry, but as many of the participants in this conference are unfamiliar with the Cement manufacturing I shall shortly give a description hereof in order to give the entire forum a better understanding of what I have to say about the use of gas in cement kilns.

SLIDE #2

Cement, the gray powder used for concrete is a chemical compound derived from Limestone and Clay or Shale and Fuel for burning. Approximately 75% Limestone and 25% Clay or Shale is extracted from quarries, crushed and homogenized in stockpiles.

These raw materials are extracted from the stockpiles and exactly proportioned by weight before fed to a grinding mill system, where they are dried and ground to a fine powder called raw meal which is homogenized in silos to a very narrow tolerance of the chemical components.
The raw meal is extracted from the silos and fed to the kiln system where it is calcined and burned, fusing together the components into clinker. The clinker is cooled and stored in silos or stockpiles.

The final process is grinding of the clinker together with 5% raw gypsum, storage of the cement in silos, and shipment to consumers either in Bulk or Paperbags.

A cement kiln uses from 700 to 3000 kcal/kg clinker depending on the kiln system used and 100 to 150 KWh/ton of cement. This means that the cement industry is one of the major consumers of energy.

In order to be all inclusive in our evaluation of natural gas used in cement kiln systems, I shall shortly describe the evolution of cement kiln systems over its 100 year history.

Small rotary kilns were used in the early days, but difficulties in homogenizing the dry powdered raw meal gave away to wet kiln systems where the raw material was interground with about 35% water, facilitating the homogenization of the resultant pumpable slurry. Upto the second World War relatively small capacity units of 200 to 400 MTPD using the dry or wet process were the standard.
As Cement Engineers strived to lower fuel consumption, kilns grew in capacity, in diameter and length with a multitude of internal heat exchange devices in order to increase the gas to raw material exposure, such as drain system, crosses, lifters, etc.

In the early fifties the suspension preheater came on the market. A short rotary kiln preceded by cyclones, normally four of them in series.

In USA the suspension preheater was nearly a total fiasco, in Europe a nearly complete success. The reason for this was related to the available raw materials and the detrimental influence trace elements such as chlorides, sulphates and alkalies have on the process.

Fuel was always relatively cheap in USA and always expensive in Europe. Thus, the pressure for Fuel improvement in the USA was secondary to development of Labor saving approaches, in contrast to Europe where the fuel cost was the dominating concern.

The long wet kilns were therefore developed to perfection in the USA whereas Europe concentrated on perfecting the dry process suspension preheater.

SLIDE #5

The oil crisis in the early seventies made a distinct impact on the cement industry, although more so in Europe and Japan than in USA where
local natural fuels were used in contrast to Europe and Japan where most fuels are imported. The latest important development of the kiln system was born in Japan in the early seventies with the introduction of the precalciner, suspension preheater kiln where the raw meal is calcined in a separate vessel.

This system does not make remarkable improvement in fuel economy but it permits the cement manufacturer to use larger systems, it facilitates removal of harmful trace elements from the process, besides, it increases utilization, decreases refractory consumption, and permit a much more steady and trouble free operation.

A rash of conversions of straight kilns and conventional suspension preheater kilns were undertaken worldwide and nearly all new project incorporate this technology.

A late development in the USA may have special interest to countries where power distribution is not extensive, this allows the cement plant to supply its own power requirement at an efficient level.

This idea of using waste heat from the cement process for generating power is not new, but today's much better understanding of the chemical interaction of trace elements in raw materials has made it possible to develop this approach with excellent results.
The primary fuels used in the cement industry is fuel oil, gas, and solid fuels such as Coal and Lignite. In the United States all these fuels are used. Many plants are equipped to burn all these types of fuel and are equipped with combination burners using whatever fuel is cheapest at any particular time.

Secondary fuels are being used on a rapidly increasing scale. Waste products such as ordinary household garbage, industrial waste including toxic fluids, husks from various seeds such as coton and rice, wood chips, graphite, used lubrication oil, etc. are being introduced together with a primary fuel in percentages up to 30% of the total heat requirement.

For Thailand we will restrict ourselves to compare the primary fuels and their influence on product and operation.

The Portland Cement Association in the United States has made extensive tests of clinker burned by fuel oil, gas and coal and has based on their findings stated:

"Clinker and consequently cement is of equal quality whether burned with fuel oil, gas or coal as long as the raw materials used are adjusted for the contamination by Ash and or Sulpher originating from the fuel."
SLIDE #7

The table on the Slide relates to Thailand Fuels and gives basic Data for Gas Oil Coal and Lignite.

SLIDE #8

Applying these basic data to a modern 4000 MTPD precalciner kiln, we find that the volume of combustion gases developed by burning is compared with oil 22% larger for Gas, 6.8% larger for Coal and 43.5% larger for Lignite. If the plant is designed for the fuel requiring the highest amount of combustion gases and is equipped with a variable speed exhaust fan, the operator will have no trouble attaining the capacity required, but if the plant was designed for burning fuel oil there may be difficulties in reaching design capacity with Gas and Lignite.

Once the operator is aware of these factors, he can adjust and interchange between fuels without affecting the quality of his product.

SLIDE #9

Gas was always the preferred fuel by kiln operators due to its ease of handling and regulation, but with the introduction of the precalciner unexpected problems have arisen.

To the best of my knowledge, gas firing of a precalciner has only been attempted in three (3) plants: Two (2) in the United States and one (1)
in Canada. Only the plant in Canada is still burning gas in the precal-
ciner; the two (2) in the USA have reverted to coal as the cheapest fuel at the present time.

In all three (3) cases the precalciner was of the SF type supplied by The Fuller Company as illustrated on the Slide.

The problem encountered was two fold:

1) During normal start-up, the kiln system is preheated by a flame in the rotary kiln. Feed is added and the precalciner is ignited when the Stage One exhaust temperature has reached a predetermined level.

When using fuel oil or coal in the precalciner ignition has never posed a problem, but using gas, the fuel did not ignite. This problem has been solved by increasing the preheating temperature and by using the temperature in the precalciner to trigger the start of feed and ignition. In the SF system the hot kiln gases pass through the vessel just after they exit from the kiln. Other manufacturers of precal-
ciners using a different flow of the hot gases may have considerably more difficulty igniting the gas in the precalciner and may have to design a special preheater for this purpose.

2) The second problem encountered was after-burning of the gas in Stage Four preheater cyclone. This problem was solved by moving the gas burners to a new and lower position in the precalciner vessel, giving the gas more retention time to burn completely before exhausting from
the vessel.

The experience described relates only to Fuller's SF Precalciner. Looking at the design of other manufacturer's precalciner, there is reason to believe that gas cannot be used without extensive "Trial and Error Testing" during actual operation.

In any event use of extreme caution is recommended. Gas may be difficult to ignite and may require longer time to fully combust, but giving the right combination of circumstances, gas could cause serious explosions.

I wish to thank you for your attention. Thank you very much.
BUILDING AND MANAGING
A PETROCHEMICALS INDUSTRY
IN TODAY'S ECONOMY

A presentation by
Gordon Mounts
Vice President/General Manager
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THAILAND - US Natural Gas Utilization Symposium
Bangkok, Thailand February, 1984
GOOD AFTERNOON. I'M ESPECIALLY PLEASED TO BE HERE TO SPEAK ABOUT THE EASTERN SEABOARD OF THAILAND AND THE THAILAND PROGRAM FOR UTILIZATION OF ITS NATURAL GAS RESOURCES.

YOU COULD SAY WE ARE A WORLD APART -- GEOGRAPHICALLY -- AND THAT WOULD BE CORRECT. AT THE SAME TIME, HOWEVER, WE HAVE CLOSE TIES THROUGH OUR BUSINESS AND TECHNICAL INTERESTS, ESPECIALLY THE NATURAL GAS UTILIZATION TOPICS WE HAVE BEEN DISCUSSING FOR THE LAST THREE DAYS. MANY OF YOU MAY BE AWARE OF UNION CARBIDE'S HISTORY AND CAPABILITIES IN DEVELOPING NATURAL RESOURCES.

FOR INSTANCE, WE HAVE BEEN USING NATURAL GAS LIQUIDS AS A CHEMICAL FEEDSTOCK FOR 65 YEARS. AS YOU MIGHT EXPECT FROM THAT BACKGROUND, WE HAVE A DEEP AND ABIDING INTEREST IN THE OPTIMUM USE OF NATURAL RESOURCES. WE BELIEVE IN AND THOROUGHLY SUPPORT THE AIMS AND OBJECTIVES OF THIS SYMPOSIUM.

I SHOULD MENTION THAT WE AT UNION CARBIDE HAVE SHARED AN EXCELLENT RELATIONSHIP WITH THE THAI BUSINESS COMMUNITY THROUGH UNION CARBIDE THAILAND LIMITED. WE TRUST THAT OUR LONG AND FULFILLING HISTORY OF DOING BUSINESS HERE HAS CONTRIBUTED TO THAILAND'S COMMERCIAL DEVELOPMENT.
PETROCHEMICALS

OUR THAI SUBSIDIARY TRADES CHEMICALS SUCH AS SOLVENTS, GLYCOL ETHERS, AND ACRYLATES, AND OPERATES A UNIQUE FLOATING TANK FARM FOR UNLOADING BARGES. IT ALSO OPERATES A PLANT FOR MANUFACTURING LATEX PRODUCTS. WE SELL EVEREADY BATTERIES IN THAILAND, AND CARBON ELECTRODES. I UNDERSTAND THAT OUR MOLECULAR SIEVE PURIFICATION TECHNOLOGY HAS BEEN APPLIED IN YOUR GAS HANDLING SYSTEMS.

IN THINKING ABOUT THE EASTCOAST OF THAILAND, IT OCCURS TO ME THAT THIS COAST OF YOURS MIGHT BE COMPARED WITH ONE OF OUR COASTS -- OF COURSE I MEAN THE GULF COAST OF THE U.S. THIS IS WHERE WE HAVE PLENTIFUL SUPPLIES OF OIL AND NATURAL GAS, AND WHERE THE U.S. PETROCHEMICAL INDUSTRY EXPERIENCED RAPID GROWTH AFTER THE SECOND WORLD WAR.

YOU COULD SAY THAT OUR PETROCHEMICAL INDUSTRY GREW TO MATURITY IN THE POST WAR PERIOD. IT WAS BORN, HOWEVER, MORE THAN 40 YEARS EARLIER -- 1918 -- IN THE WEST VIRGINIA TOWN OF CLENDENNIN WHERE UNION CARBIDE BUILT ITS FIRST PETROCHEMICAL PLANT FOR THE PRODUCTION OF ETHYLENE.
PETROCHEMICALS

DURING THAT POST WAR PERIOD OF SUBSTANTIAL CONSTRUCTION, AMERICAN COMPANIES -- UNION CARBIDE INCLUDED -- DIDN'T BUILD AN INDUSTRY WITHOUT MAKING MISTAKES. WE LEARNED A GREAT DEAL TOO. THAT BRINGS ME TO MY SUBJECT: "PLANNING, BUILDING AND MANAGING A PETROCHEMICALS INDUSTRY IN TODAY'S ECONOMY."

NOW, I'M SURE THAT NO ONE IN THIS ROOM WOULD EVER EXPECT A COMPLETE DISCUSSION OF THAT TOPIC FROM ONE MAN IN 30 MINUTES. A PARTIAL DISCUSSION MIGHT BE HANDLED BY 10 MEN IN 10 DAYS.

THIS AFTERNOON I'M GOING TO CONCENTRATE ON TWO SPECIFIC AREAS: (1) BUSINESS PLANNING AND TECHNOLOGY IMPLEMENTATION IN THE PETROCHEMICALS INDUSTRY AND (2) A MARKET AND ECONOMIC REVIEW OF ETHYLENE GLYCOL. GLYCOL IS A BASIC PETROCHEMICAL IN ALL INDUSTRIAL SOCIETIES, AND DEMONSTRATES THE DERIVATION AND END USES OF A PETROCHEMICAL

OUR CONCEPTS FOR PROGRAM PLANNING AND TECHNOLOGY IMPLEMENTATION HAVE EVOLVED FROM EXPERIENCE GAINED IN BUILDING PETROCHEMICAL COMPLEXES FOR 65 YEARS. THE HISTORY OF OUR PROGRAM DEVELOPMENT CONCEPTS
PETROCHEMICALS

ARE SHOWN ON THE NEXT TWO SLIDES. I CAN SPEAK PERSONALLY ABOUT THE PERIOD FROM 1958 TO THE PRESENT, DURING WHICH WE DEVELOPED MANY OF OUR CURRENT CONCEPTS IN PROGRAM PLANNING AND MANAGEMENT.

PROGRAM PLANNING IS DEFINED AS THE PROCESS OF DEFINING, ASSEMBLING, PRIORITIZING, TIMING, AND ASSIGNING ALL RESOURCES NECESSARY FOR SUCCESSFUL AND OPTIMUM EXECUTION OF A PETROCHEMICAL PROJECT. WE CALL THE ENTIRE PROCESS A PROGRAM MANAGEMENT SYSTEM.

THE BASIC CONCEPTS...

THINK - PLAN - DO - AUDIT

...THAT WHICH APPEARS SO SIMPLE BECOMES INCREDIBLY COMPLEX WHEN IMPLEMENTING TECHNOLOGY IN A BILLION DOLLAR PETROCHEMICAL FACILITY. THE CONCEPTS MUST BE EXPANDED TO MEET THE SITUATION, AND ACTIONS BASED ON THE CONCEPTS MUST ALWAYS FIT THE BUSINESS STRATEGIC PLAN.

THE SUCCESSFUL IMPLEMENTATION OF TECHNOLOGY DEPENDS ON THE DEVELOPMENT OF A STRATEGIC PLAN FOR THE BUSINESS. THE BASIC NEED IS TO DECIDE WHAT YOU WANT. SUCCESS MUST BE DEFINED. AN EXAMPLE OF A BUSINESS STRATEGY IS TO INCREASE MARKET SHARE BY HAVING THE RIGHT PRODUCT IN THE RIGHT MARKET AT THE LOWEST COST AT THE RIGHT TIME.
AFTER DEFINING THE BUSINESS STRATEGY, A NUMBER OF ELEMENTS SHOULD BE ASSEMBLED AND IMPLEMENTED: SLIDE 5

*SUCCESS NEEDS*

- PROGRAM MANAGER
- STRATEGIC BUSINESS PLAN
- PROVEN, LEADING TECHNOLOGY
- VIABLE PROJECT FINANCING
- QUALITY PROJECT EXECUTION
- ON TIME PROJECT COMPLETION
- QUALITY OPERATIONS
- RELIABLE & ECONOMIC SOURCE
- RAW MATERIALS
- DEFINED AND DEVELOPED MARKETS
- FINANCIAL PERFORMANCE MEASURED AGAINST STANDARDS

OR IN MANAGEMENT CONCEPTS

THINK - PLAN - DO - AUDIT

NEXT, THE DEFINITION OF THE PROGRAM PLAN LEADS TO A LIST OF 10 PROGRAM ELEMENTS: SLIDE 6

1 BUSINESS STRATEGY
2 SPONSOR'S OBJECTIVES
3 SPONSOR TEAM
COMMERCIAL OBJECTIVES FLOW FROM THE BUSINESS STRATEGY. THESE OBJECTIVES TRANSLATE THE STRATEGY INTO CONCRETE GOALS FOR THE PROGRAM; THEY FORM THE PRIORITY BASE; THEY ALLOW THE NECESSARY TRADE-OFFS TO BE MADE. IT IS IMPORTANT THAT THE OBJECTIVES RECOGNIZE THE NEED FOR FLEXIBILITY AND REFLECT REAL-WORLD CHANGES. THEY MUST SET CHALLENGING TARGETS AND TIE TOGETHER THE EXECUTION AND OPERATING PHASES.

EVERY PROGRAM, OF COURSE, NEEDS A MANAGEMENT GROUP, WHICH WE CALL THE SPONSOR TEAM. THIS IS COMPOSED OF KEY MANAGEMENT PEOPLE WHO REPRESENT CRITICAL AREAS OF THE PROGRAM: OWNER, CONTRACTOR, AND OPERATOR. THE JOB OF THE SPONSOR TEAM IS TO DIRECT RESOURCES IN ORDER TO ACHIEVE THE COMMERCIAL OBJECTIVES. IT'S NOT A DAILY ACTIVITY. THE TEAM MEETS AS NECESSARY TO KEEP THE PROJECT ON TRACK.
PROJECT MANAGEMENT IS A SUBJECT THAT HAS BEEN STUDIED INTENSELY - BOOKS HAVE BEEN WRITTEN ON IT. ALL RECOGNIZE THE NEED FOR A PROJECT MANAGER AND A PROJECT TEAM THAT DEVELOPS THE PROJECT PLAN.

REPRESENTATIVES MAY INCLUDE PROJECT MANAGEMENT, ENGINEERING, CONSTRUCTION, TECHNOLOGY, OPERATION, AND DISTRIBUTION. THERE ARE USUALLY SEVERAL TEAMS, FOR EXAMPLE, INSIDE BATTERY LIMITS, OUTSIDE BATTERY LIMITS, DISTRIBUTION, AND OFFSITES. HOW THESE TEAMS TIE IN WITH OTHER PROGRAM ELEMENTS IS REPRESENTED IN THIS SLIDE.

PROJECT PLANNING, ALONG WITH PROJECT MANAGEMENT, IS A WELL-KNOWN SCIENCE, AND MANY EXCELLENT TECHNIQUES ARE AVAILABLE. THE PLAN SHOULD INCLUDE:

- ENGINEERING PLAN
- PROCUREMENT PLAN
- CONSTRUCTION PLAN
- COMMISSION AND START-UP
- WARRANTY OPERATION
OPERATIONAL PLANS ARE DEVELOPED DURING THE PROJECT IMPLEMENTATION PHASE. PLANS FOR MARKETING, PLANS FOR MANUFACTURING, INCLUDING PERSONNEL TRAINING, AND MAINTENANCE PLANS INCLUDING MATERIALS MANAGEMENT. METHODS FOR PRODUCT DISTRIBUTION NEED TO BE DETERMINED. THIS PHASE REQUIRES CAREFUL PLANNING AND CONTROL BY THE SPONSOR TEAMS OR THEIR REPRESENTATIVES.

AFTER A YEAR OF OPERATION, WE SUGGEST A COMPLETE PROGRAM AUDIT. A WRITTEN ANALYSIS BY THE SPONSOR TEAM IS A GOOD IDEA TO ANSWER QUESTIONS SUCH AS: IS THE FACILITY MEETING OBJECTIVES? IF NOT, WHY NOT? WHAT CAN BE DONE TO CORRECT DEFICIENCIES? WHAT HAS BEEN LEARNED?

WE KNOW THAT THE PROGRAM MANAGEMENT SYSTEM WORKS. BUT IT MUST START WITH A DEFINITION OF WHAT IS WANTED AND A PROPER BALANCE OF PROGRAM ELEMENTS. THE OWNER OR HIS REPRESENTATIVE MUST PROVIDE THE EXPERIENCE THAT, IN COMBINATION WITH A COMPETENT CONTRACTOR, WILL YIELD THE OPTIMUM COMBINATION FOR A SUCCESSFUL PROGRAM. WE HAVE FOUND MANY TIMES THAT THE PERSPECTIVE OF AN OWNER/OPERATOR IS NECESSARY FOR SUCCESSFUL IMPLEMENTATION.
PETROCHEMICALS

ONCE AGAIN, THE KEY INGREDIENTS ARE:  
THINK - PLAN - DO - AUDIT

NOW THAT WE HAVE COVERED THE BASIC ELEMENTS 
OF PROGRAM MANAGEMENT FOR A PETROCHEMICAL COMPLEX,  
LET'S LOOK AT A KEY PETROCHEMICAL -- ETHYLENE GLYCOL  
-- IN TERMS OF MARKETING AND ECONOMICS.

YOU'RE PROBABLY FAMILIAR WITH HOW ETHYLENE  
GLYCOL IS DERIVED FROM NATURAL GAS CONCENTRATE, WHICH  
IS THE MOST ECONOMIC STARTING MATERIAL FOR GLYCOL.

ETHYLENE FROM THE ETHANE CRACKER IS CONVERTED 
TO ETHYLENE OXIDE, AND THE OXIDE IS THEN REACTED WITH 
WATER. THE PRIMARY PRODUCT IS ETHYLENE GLYCOL, WITH 
SMALLER AMOUNTS OF DIETHYLENE, TRIETHYLENE AND 
TETRAETHYLENE GLYCOL.

THE CHEMISTRY IS STRAIGHT FORWARD AND THE 
PROCESS SEEMS SIMPLE. OF COURSE, DESIGNING, ENGINEERING, 
CONSTRUCTING, AND SUCCESSFULLY OPERATING A 50 MILLION 
TON PER YEAR FACILITY IS BY NO MEANS "SIMPLE". IT 
REQUIRES ALL THE ELEMENTS OF GOOD BUSINESS PRACTICES, 
PROGRAM MANAGEMENT, AND TECHNOLOGY IMPLEMENTATION.
PETROCHEMICALS

ETHYLENE GLYCOL IS AN INTERESTING DOWNSTREAM PRODUCT BECAUSE IT, IN TURN, IS THE STARTING POINT FOR A LONG CHAIN OF ADDITIONAL PRODUCTS. THE ENTIRE PROCESS EXTENDS FROM NATURAL GAS ALL THE WAY LITERALLY TO THE SHIRT ON YOUR BACK.

I'LL COVER BRIEFLY WHAT THESE DOWNSTREAM PRODUCTS ARE, AND THEN I HAVE SOME DATA ON THE WORLDWIDE MARKET PICTURE AS WE SEE IT. IN TERMS OF VOLUME, POLYESTER FIBERS AND AUTOMOTIVE ANTIFREEZE ARE THE MOST SIGNIFICANT APPLICATIONS FOR ETHYLENE GLYCOL. HERE IN THAILAND, OF COURSE, THERE ARE FEW USES FOR ANTIFREEZE AND 99+ PERCENT OF THE ETHYLENE GLYCOL IS CONVERTED INTO POLYMERS.

POLYESTER FIBER, AS I'M SURE YOU KNOW, IS A HIGHLY VERSATILE MATERIAL THAT HAS BECOME THE BASE FOR A WHOLE RANGE OF TEXTILE PRODUCTS - FROM TIRE CORD TO SOCKS, SUITS AND SHIRTS.

POLYESTER RESINS ARE CONVERTED INTO BOTTLES FOR SOFT DRINKS, AND INTO FILM FOR PHOTOGRAPHIC USES AND MAGNETIC TAPE. THERE ARE SMALLER, BUT IMPORTANT, INDUSTRIAL USES FOR GLYCOL AS WELL.
PETROCHEMICALS

POLYESTERS ACCOUNT FOR ABOUT 49 PERCENT OF
THE ETHYLENE GLYCOL PRODUCED WORLDWIDE, ACCORDING TO
OUR ESTIMATES. ANTIFREEZE PRODUCTS MAKE UP 31 PERCENT
OF THE END USES, AND OTHER APPLICATIONS 20 PERCENT.

IN GENERAL TERMS, OF ALL ETHYLENE OXIDE
PRODUCTION, 62 PERCENT IS CONVERTED TO GLYCOLS
AND 38 PERCENT TO DERIVATIVES SUCH AS GLYCOL ETHERS,
SURFACTANTS, FUNCTIONAL FLUIDS, AND POLYETHYLENE
GLYCOLS.

THE WORLD OVERVIEW WE SUGGEST FOR GLYCOL
AND ETHYLENE OXIDE IN THE 1980's INCLUDES WIDE
DIFFERENCES IN REGIONAL ECONOMICS, EQUALLY WIDE
DIFFERENCES IN SECURITY OF SUPPLY, AND FORCED
RATIONALIZATIONS IN JAPAN AND EUROPE.

IN 1982, CONSUMPTION OF ETHYLENE OXIDE
AMOUNTED TO 4.9 MILLION METRIC TONS. THE UNITED STATES
WAS THE LARGEST USER, TAKING 49 PERCENT, FOLLOWED BY
WESTERN EUROPE AT 25 PERCENT, JAPAN 10 PERCENT, AND
EASTERN EUROPE 9 PERCENT. ASIA ALTOGETHER CONSUMED 7
PERCENT, OR ABOUT 240,000 TONS.
PETROCHEMICALS

THE NAMEPLATE OR DESIGN CAPACITY OF OXIDE PLANTS TOTALLED SOME 7.2 MILLION TONS IN 1982. YOU CAN SEE ON THIS SLIDE HOW THAT TOTAL IS SHARED BY THE MAJOR MANUFACTURERS.

WHAT KIND OF GROWTH DO WE FORECAST FOR THIS DECADE? THE WORLD AVERAGE SHOULD BE A LITTLE MORE THAN 3 PERCENT A YEAR, WITH GROWTH INCREASING TOWARDS THE END OF THE DECADE. EXCLUDING THE U.S. AND CANADA, HOWEVER, THE WORLD AVERAGE IS EXPECTED TO BE OVER 4 PERCENT, BUT WITH A GROWTH DECREASE PREDICTED.

THIS SLIDE SHOWS OUR OPINION OF HOW THE ETHYLENE OXIDE MARKET SEGMENTS WILL PERFORM IN THE TWO PERIODS 1981 - 1986 AND 1986 - 1991. ANTIFREEZE WILL BE INCREASING THE LEAST; POLESTER THE MOST. NEARLY HALF OF THE TOTAL WORLD GROWTH 44% WILL BE IN POLYESTER MARKETS. SPECIFICALLY, THAT GROWTH IS IN ETHYLENE GLYCOLS FROM WHICH POLYESTER IS MADE. AND, VIRTUALLY ALL OF THE GLYCOLS CONSUMED IN THAILAND ARE USED TO MANUFACTURE POLYESTER FIBERS.
PETROCHEMICALS

Therefore any meaningful increase in polyester glycol demand would require construction of another polyester fiber plant. Without an increased demand, growth would be limited in Thailand, to incremental expansion of existing polyester plants.

On the supply side, at present there are 10 ethylene oxide plant startups scheduled for the period 1984-87. They will add about 1.3 million tons of potential production to existing worldwide capacity.

Here we have an overview of the supply and demand balance for the next 10 years. As we mentioned, we expect to see wide regional differences.

As you can see represented here, Asia should be a net importer for the entire period. The mid-east and Africa will change from being an importer to the role of a major exporter. Western Europe, Latin America, and Japan should end the decade as importers. North America will be a consistent exporter throughout the time span.
BEFORE CONCLUDING MY PRESENTATION TODAY, I WANT TO DISCUSS THE ECONOMICS OF MANUFACTURING AND MARKETING ETHYLENE GLYCOL. THE FOLLOWING THREE SLIDES SUMMARIZE THE COSTS INVOLVED IN BUILDING A TYPICAL 50,000 MTPA PLANT AND THE ROI THAT COULD BE EXPECTED FOR THREE LEVELS OF MARKET PRICE.

AS YOU WOULD EXPECT, THE ECONOMICS OF MONOETHYLENE GLYCOL (MEG) MANUFACTURE DEPEND HEAVILY ON RAW MATERIAL COSTS AND SIZE OF THE FACILITY. THE PROFITABILITY OF A 50,000 MT/YEAR MEG FACILITY FOR THAILAND HAS BEEN ANALYZED. NOT KNOWING THE EXACT ETHYLENE PRICE BUT BEING AWARE OF SOME OF YOUR GUIDE LINES THE ANALYSIS HAS BEEN DONE USING U.S. GULF COAST ETHYLENE PRICE. THE REST OF THE ECONOMIC FACTORS ARE PER THE CONFERENCE GUIDELINES OR ARE OBTAINED FROM OTHER WORK WE HAVE DONE IN THAILAND. THE BASE FACTORS ARE SHOWN IN FIGURE I. THIS BASIS RESULTS IN THE COSTS AND INVESTMENTS SHOWN IN FIGURE II. THESE TWO SETS OF DATA ARE TRANSLATED INTO PRICES NECESSARY TO EARN A PROFIT IN FIGURE III. AS YOU CAN SEE, A PRICE OF APPROXIMATELY $750 PER MT IS NECESSARY TO EARN A 10 PERCENT ROI AT IN THAILAND USING THE CURRENT U.S. GULF COAST ETHYLENE PRICE.
PETROCHEMICALS

BECAUSE OF CURRENT WORLDWIDE MEG MARKET PRICES SUCH A PRICE IS NOT COMPETITIVE UNLESS YOU CLOSE THE BORDER. EVEN AT YOUR CURRENT 7.7 PERCENT TARIFF, MEG CAN BE PURCHASED UP TO $50 PER MT LESS THAN $750 IN THAILAND TODAY. THE REASON FOR THIS STATE OF AFFAIRS IS THAT MANY PEOPLE ARE TODAY SELLING INCREMENTAL POUNDS OF ETHYLENE. THAT PRICING APPROACH WOULD CHANGE BECAUSE THE CURRENT LEVEL OF PRICING IS NOT SUSTAINABLE LONG TERM, OR AT THE FIRST SIGN OF MARKET TIGHTNESS. WHEN THAT OCCURS, A MEG UNIT IN THAILAND SHOULD MAKE ECONOMIC SENSE.

I DON'T KNOW IF YOU ARE FAMILIAR WITH THE TERM "BOTTOM LINE." I EXPECT MANY OF YOU ARE. FOR ACCOUNTANTS, IT MEANS SIMPLY PROFIT OR LOSS. WE OFTEN USE THE TERM TO MEAN MORE THAN THAT -- THE FINAL RESULT, THE OVERALL CONCLUSION, THE SUMMARY OF WHAT HAS BEEN COVERED, THE ESSENCE OF THE DISCUSSION.

THE BOTTOM LINE FOR EFFICIENT, EFFECTIVE PROGRAM MANAGEMENT IS THAT WE AT UNION CARBIDE FEEL THAT THE PROGRAM MANAGEMENT SYSTEM IS ABSOLUTELY ESSENTIAL.
PETROCHEMICALS

THE BOTTOM LINE FOR OXIDE AND GLYCOL IS THAT WE BELIEVE THE NEXT SEVERAL YEARS WILL BE CHARACTERIZED BY MODEST GROWTH RATES AND A SURPLUS OF OPERATING CAPACITY.

IF I MAY, I WOULD LIKE TO ADD A FINAL BOTTOM LINE. THE BOTTOM LINE FOR YOUR EASTERN SEABOARD PERTOCHIMICAL COMPLEX IS THAT THE THAI GOVERNMENT AND THE PETROLEUM AUTHORITY OF THAILAND ARE TO BE CONGRATULATED FOR AN IMAGINATIVE, FAR-SIGHTED PROGRAM THAT IS BEING WISELY FULFILLED.
USA - PETROCHEMICAL INDUSTRY
STARTED IN
CLENDENIN, WEST VIRGINIA
BY
UCC
DEVELOPMENT OF PROGRAM MANAGEMENT CONCEPTS


TAFT CUBATAO BRAZIL PRENTISS

PONCE SARINA ITALY STAR

TAIWAN

PROGRAM MANAGEMENT

DEFINITION
OF
FACILITY

PRELIMINARY
BUDGET
DEFINITION

SPONSOR
OBJECTIVE
SPONSOR
TEAMS
DEVELOPMENT OF PROGRAM MANAGEMENT CONCEPTS

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PROGRAM MANAGEMENT

OUTLINE OF PROJECT

PROJECT TEAMS
PROGRAM PLANNING

THE PROCESS OF DEFINING, ASSEMBLING, PRIORITIZING, TIMING, AND ASSIGNING ALL RESOURCES NECESSARY FOR SUCCESSFUL AND OPTIMAL EXECUTION OF A PETROCHEMICAL PROJECT.
WE CALL IT

PROGRAM MANAGEMENT SYSTEM
THINK - PLAN - DO - AUDIT

ALL NEEDED
FOR SUCCESSFUL
TECHNOLOGY
IMPLEMENTATION
ONE EXAMPLE OF BUSINESS STRATEGY IS:

HAVING THE RIGHT PRODUCT IN THE RIGHT MARKET AT THE LOWEST COST AT THE RIGHT TIME
SUCCESS NEEDS

- Program Manager
- Strategic Business Plan
- Proven, Leading Technology
- Viable Project Financing
- Quality Project Execution
- On Time Project Completion
- Quality Operations
- Reliable & Economic Source
- Raw Materials
- Defined and Developed Markets
- Financial Performance Measured Against Standards

Or in Management Concepts

Think - Plan - Do - Audit
PROGRAM ELEMENTS

1. BUSINESS STRATEGY
2. SPONSORS OBJECTIVES
3. SPONSOR TEAM
4. PROJECT MANAGER/PROJECT TEAM
5. PROJECT PLAN
6. PROJECT IMPLEMENTATION
7. OPERATIONAL PLANS
8. OPERATION
9. PROGRAM AUDITS
10. CONTINGENCY PLANS
   (THE REAL WORLD EXISTS)
COMMERCIAL OBJECTIVES

DEVELOP FINANCING PLANS

DEFINE WHAT'S IMPORTANT
(RELATIVE RANKING)

DEFINE TRADE OFF'S

NEED FOR FLEXIBILITY - REAL WORLD CHANGES

SET CHALLENGING TARGETS

TIE EXECUTION PHASE AND OPERATING PHASE

EXPECT AND MANAGE CONFLICT
SPONSOR TEAM

KEY MANAGEMENT REPRESENTING

CRITICAL AREAS OF PROGRAM

- OWNER
- CONTRACTOR
- OPERATOR

DIRECT RESOURCES TO ACHIEVE
COMMERCIAL OBJECTIVES
PROJECT TEAM

APPROPRIATE RESOURCES TO IMPLEMENT PROJECTS

PROJECT MANAGEMENT
ENGINEERING
CONSTRUCTION
TECHNOLOGY
OPERATIONS
DISTRIBUTION

PROJECT TEAMS

ISBL
OSBL
DISTRIBUTION
OFFSITES

NUMBER DEPENDS UPON PROJECT SIZE AND COMPLEXITY
I OWNER I

I OBJECTIVES I

PROGRAM MANAGEMENT

SPONSOR TEAM

ISBL TEAM

OFF-SITES TEAM

CONTRACTOR MANAGEMENT

OSBL TEAM

DISTRIBUTION TEAM
PROJECT PLAN

ENGINEERING PLAN
PROCUREMENT PLAN
CONSTRUCTION PLAN
COMMISSIONARY AND START UP
WARRANTY OPERATION
OPERATIONAL PLANS

MARKETING
MANUFACTURING
TRAINING
SCHEDULING
MAINTENANCE
DISTRIBUTION
BASIC CONCEPTS

THINK - PLAN - DO - AUDIT
EO/G Product Chain
Industry Worldwide

Ethylene Oxide

To Derivatives 38%

To Ethylene Glycols 62%

30% Polyester
12% Other
20% Antifreeze

Ethanolamines
Glycol Ethers
Surfactants
Functional Fluids
Polyethylene Glycols
Others
Worldwide Consumption 1982

- Western Europe: 25%
- Eastern Europe: 9%
- Japan: 10%
- Asia: 7%
- United States: 41%
- Latin America: 4%
- Middle East & Africa: 2%
- Canada: 2%

4.9 Million Metric Tons Ethylene Oxide/UCC World Share 19%
Worldwide Capacity Share

BP Group 7%
UCC 20%
ICI 6%
Shell 9%
Japan 9%
Dow 9%
BASF 7%
All Other (34) 33%

1982 Nameplate Capacity — 7.2 Million Metric Tons EO
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Balance of World</td>
<td>4.6</td>
<td>4.1</td>
</tr>
<tr>
<td>U.S./Canada</td>
<td>1.2</td>
<td>3.2</td>
</tr>
<tr>
<td>Total World</td>
<td>3.1</td>
<td>3.5</td>
</tr>
</tbody>
</table>
World Market Growth
M Metric Tons

<table>
<thead>
<tr>
<th></th>
<th>'81</th>
<th>'86</th>
<th>'91</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polyester</td>
<td>1,722</td>
<td>2,068</td>
<td>2,592</td>
</tr>
<tr>
<td>Antifreeze</td>
<td>678</td>
<td>900</td>
<td>922</td>
</tr>
<tr>
<td>Other</td>
<td>650</td>
<td>727</td>
<td>831</td>
</tr>
<tr>
<td>Derivatives</td>
<td>1,920</td>
<td>2,306</td>
<td>2,788</td>
</tr>
<tr>
<td>Total EOE</td>
<td>5,170</td>
<td>6,001</td>
<td>7,133</td>
</tr>
<tr>
<td>M Metric Tons</td>
<td>'81</td>
<td>'86</td>
<td>'91</td>
</tr>
<tr>
<td>World Growth</td>
<td>3.1</td>
<td>3.5</td>
<td>4.6</td>
</tr>
</tbody>
</table>
Worldwide EO Supply/Demand Balance
1981-1992

Maximum attainable production

Rationalization

Demand
## Regional Supply/Demand Balance

<table>
<thead>
<tr>
<th>Region</th>
<th>Early 80's</th>
<th>Mid 80's</th>
<th>Late 80's</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>Exporter</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Western Europe</td>
<td>Long</td>
<td>Rationalization</td>
<td>Importer</td>
</tr>
<tr>
<td>Latin America</td>
<td>Long</td>
<td>Balanced</td>
<td>Importer</td>
</tr>
<tr>
<td>Japan</td>
<td>Long</td>
<td>Rationalization</td>
<td>Importer</td>
</tr>
<tr>
<td>Asia</td>
<td>Importer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid-East/Africa</td>
<td>Importer</td>
<td>Major Exporter</td>
<td></td>
</tr>
<tr>
<td>PRC</td>
<td>Exporter</td>
<td>Importer</td>
<td>Exporter</td>
</tr>
<tr>
<td>Eastern Europe/USSR</td>
<td>Importer</td>
<td>Balanced</td>
<td>Balanced</td>
</tr>
<tr>
<td>Total</td>
<td>Long</td>
<td>Long</td>
<td>Long</td>
</tr>
</tbody>
</table>
FIG. I

THAILAND MEG PLANT

BASIS

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPACITY</td>
<td>50,000 MTPA MEG</td>
</tr>
<tr>
<td>OPERATING FACTOR</td>
<td>800 HR/yr</td>
</tr>
<tr>
<td>PROJECT LIFE</td>
<td>15 YEARS</td>
</tr>
<tr>
<td>CAPITAL INVESTMENT</td>
<td>$30 MM</td>
</tr>
<tr>
<td>WORKING CAPITAL</td>
<td></td>
</tr>
<tr>
<td>C$_2$H$_4$</td>
<td>$485/MT</td>
</tr>
<tr>
<td>O$_2$</td>
<td>$135/MT</td>
</tr>
<tr>
<td>CH$_4$</td>
<td>$4/MMBTU</td>
</tr>
<tr>
<td>C$_2$H$_6$</td>
<td>$4/MMBTU</td>
</tr>
<tr>
<td>POWER</td>
<td>$.06/kwh</td>
</tr>
<tr>
<td>WATER</td>
<td>$.05/Mgal</td>
</tr>
<tr>
<td>FUEL</td>
<td>$4/MMBTU</td>
</tr>
<tr>
<td>HP STREAM</td>
<td>$15.6/MT</td>
</tr>
<tr>
<td>LP STREAM</td>
<td>$11.7/MT</td>
</tr>
<tr>
<td>SKILLED LABOR</td>
<td>$4000/yr/person</td>
</tr>
<tr>
<td>UNSKILLED LABOR</td>
<td>$1700/yr/person</td>
</tr>
<tr>
<td>LABOR SUPERVISION</td>
<td>20% SKILLED AND UNSKILLED LABOR</td>
</tr>
<tr>
<td>MAINTENANCE</td>
<td>5% TOTAL INVESTMENT</td>
</tr>
<tr>
<td>ADMINISTRATIVE &amp; SUPPORT LABOR</td>
<td>20% OF ALL LABOR</td>
</tr>
<tr>
<td>PAYROLL EXTRAS</td>
<td>20% OF ALL LABOR</td>
</tr>
<tr>
<td>INSURANCE</td>
<td>2% OF FACILITIES INVESTMENT</td>
</tr>
<tr>
<td>GENERAL ADMINISTRATIVE EXPENSE</td>
<td>2% OF FACILITIES INVESTMENT</td>
</tr>
<tr>
<td>TAXES</td>
<td>35% OF NET PROFIT</td>
</tr>
<tr>
<td>DEPRECIATION</td>
<td>STRAIGHT LINE - 10 YEARS</td>
</tr>
</tbody>
</table>

651
FIG II

THAILAND MEG PLANT

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facilities Investment</td>
<td>$600.00</td>
</tr>
<tr>
<td>Working Capital</td>
<td>$108.80</td>
</tr>
<tr>
<td>Total Investment</td>
<td>$708.80</td>
</tr>
<tr>
<td>Variable Costs</td>
<td>$516.80</td>
</tr>
<tr>
<td>Fixed Costs</td>
<td>$72.00</td>
</tr>
<tr>
<td>Total Costs</td>
<td>$588.80</td>
</tr>
<tr>
<td>By-Produet Credits</td>
<td>9.06</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$579.74/MT</strong></td>
</tr>
</tbody>
</table>
FIG III

SUMMARY

MEG PRICE $/MT

<table>
<thead>
<tr>
<th>ROIAT</th>
<th>$485 (1)</th>
<th>$440</th>
<th>$520</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>$639.7</td>
<td>$606.8</td>
<td>$665.2</td>
</tr>
<tr>
<td>10</td>
<td>748.7</td>
<td>714.9</td>
<td>775.0</td>
</tr>
<tr>
<td>20</td>
<td>857.8</td>
<td>823.0</td>
<td>884.8</td>
</tr>
<tr>
<td>30</td>
<td>966.8</td>
<td>931.1</td>
<td>994.6</td>
</tr>
</tbody>
</table>

(1) U.S. Gulf Coast Basis, Market Price 1Q83
Good Morning Ladies and Gentlemen,

In the past year much publicity has been given to the forthcoming development of a major petrochemical facility in Thailand. The economic reasons for this ambitious programme are evident, and the need of this project to further industrial and commercial goals within your country is well-known.

All of you know that many of the chemicals, plastics and fertilisers produced in the world originate in the processing of natural gas. It is accepted that Thailand has large natural gas resources which can be produced for many years as an energy source and, alternatively as a feedstock for petrochemicals. This is a fortunate coincidence of availability of resources and the need of economic development. The many end products from such development will benefit living standards of the present generation and those of the future. This is a unique opportunity to Thailand's decision makers today.

This presentation will deal with the principal decisions, problems, and progressive steps that must be considered in managing the development of a major petrochemical project. A detailed programme on this subject would require many volumes of technical narrative. However, it is not an insoluble mystery nor does it require genius. Certain principles must be known and respected, an order of priorities must first be established and sequential steps taken, all leading toward the goal of sensible economic investment in a major complex consisting of a number of plants, and many support facilities which will require several years to build.
REQUIRED FEASIBILITY STUDY

One of the first but vital steps that has to be taken in the development of a petrochemical complex is to determine the economic feasibility of the undertaking.

A study has to be performed to determine that building such an industry is practicable in terms of need, economic and financial justification, and a reasonable chance of success in meeting the objectives and expectations of such an investment. Additionally a detailed study must be made in the market place to determine not only which products are needed today, but the products which will be required when the plant is finished several years ahead, and which products will continue in demand for the next 15 - 20 years during the productive life of the plant. These market studies require a combination of marketing and commercial specialists in conjunction with a major engineering firm. The obvious need is not only to determine the volume and timing of product requirements, but concurrently be able to relate this information to the probable cost of the facility to be built, and the availability of raw material required as feedstock to the chemical plants.

To establish feasibility the basic requirements of the plant must be defined (output, process route, feedstock options, product options, product quality, plant reliability/availability, time constraints imposed by the market) and preliminary studies undertaken, including
an indicative capital cost estimate for the minimum basic plant, with all optional additions separately costed, and a critical examination of all non-operating facilities and services.

Firms performing such studies must have the technical and commercial capabilities to foresee markets that could be served, and to identify the total required facility. In addition to the process plants there are many peripheral infrastructure needs to support the production facility. These include roadworks, water supply and waste disposal systems; railroads, docks, offsite materials handling, townships for the work-force and, industrial facilities to support plant maintenance and operations, and dozens of other requirements, none of which can be overlooked. Importantly, such a study must eventually include reliable estimates of the cost of the total facility required and the time duration required to build it.

There are very few companies in the world who have had the experience of dealing with the overall complexities of such a challenge. Before serious financial interest can be aroused the feasibility studies must be concluded and, appointment of a properly qualified consultant for this task is a most important consideration that will influence all subsequent steps in development of the project.

CONCEPTUAL DESIGN

The collective feasibility studies including cost estimates, market studies and knowledgeable assessment of available proven
technology lead to a conceptual design of the type, capacities and principal features of the plants to be built which will best satisfy the objective of this major investment, and assure dependable production from the plants. Comparative studies must be made of the capital cost necessary to achieve different production programmes. This conceptual design is by its very definition preliminary. It can be modeled by computer techniques encompassing all the facilities to be built, the relative arrangements of plants and support units, the first estimate of costs and a general assessment of raw material to be processed and products to be produced.

The programme will be built up starting from an ideal commissioning sequence, assessing what can be achieved in construction, procurement and engineering, then reviewing, commissioning and so on in an iterative process. Of particular importance are the overlaps between phases, e.g. between design and construction; between procurement, fabrication and construction; between each construction function. As with capital cost estimates it is essential always to compare the programme, when developed, with past experience.

There are a number of computer programs available to simulate the many combinations of variable cost elements which deserve consideration in such a study. Following this must come the extensive planning effort necessary to start and complete a task of such dimensions.

It is most important that capital cost estimates (and indeed all significant estimates for the project) should, once prepared, be assessed against experience, rules of thumb and established relationships.
STARTING THE PROJECT

Between conceptual design and the reality of a world scale petrochemical plant there are years of work and millions of manhours to be spent in design detailing, planning, engineering, constructing and commissioning the facilities. The daunting question arises as to how does one begin such a task?

The magnitude of the project principally rests in the plan to build all the process plants with the necessary supporting facilities and infrastructure such as service roads, railroads, communications, etc., on a sustained schedule.

While the overall goal challenges one's imagination and capability, there is consolation in knowing that what has been done before in other countries will now be done in Thailand. When each task is separately identified, it reduces to a manageable scale and a project execution plan must be developed to solve problems as they arise.

If there is a single requirement to successful execution of the overall plan it is experience, and knowing the relative priority of each task and the inter-relationships of the activities involved.

People are the key; there is an absolute need for people who can make things happen within the framework laid down. Care should therefore be taken to ensure a fully experienced, confident management team with the ability to work together effectively and under periods of stress.
Early appointment is vital. Where possible the client construction manager should be appointed at the outset of the project, before definition, the managing contractor's construction manager as soon as possible after contracts are signed.

The typical petrochemical complex in the western world was developed over a period of many years, often by addition or expansion of one or two units at a time. A grassroots facility is a much greater challenge and more difficult to manage because so many activities must be planned and constructed at the same time in a rational, cost effective programme.

In starting a project of this size and complexity, with all the major risks and costs entailed, it is obvious that experience of similar projects would be an extremely valuable asset. In the United States and Europe most major chemical and oil companies staff such ventures from their own large engineering and operating groups. Other companies engage specialist consulting firms to assist their staff. If the venture group or principal does not have enough experienced personnel to organise and direct a project of this size, it should engage a major engineering firm with comparable experience and, the technical resources needed to supply hundreds of engineers and specialists wherever they are needed.

The overall management of a project of this scope requires understanding and solution of innumerable technical, financial and commercial problems. Sophisticated planning and coordination
skills are required to ensure that the overall programme moves effectively from pre-contract stage through plant commissioning, and operation up to design capacity. This will involve several years of intensive, expert attention to a wide number of major tasks and thousands of important details.

GENERAL PROJECT PLAN (PROJECT EXECUTION STRATEGY)

During the definition stage a clear project strategy has to be developed, i.e. how is the project to be managed, what project resources will be required and when, how work will be divided up and the effect of client/contractor/vendor interface, what roles are consultants and contractors to play, what type of contract, what are the priorities, what other projects are occurring in the same geographical area (e.g. enough skilled labour, industrial relations climate), etc. Project strategies will vary widely according to the type of project and individual preferences and we do not suggest or recommend a single formula. What is important is that the strategy should be coherent and realistic, that it should be clearly expressed, discussed and agreed by those responsible for the project, and communicated to all involved. A major aim of the project strategy must be to build an effective relationship between clients and contractors.

There are many possible plans which could be followed in developing a major petrochemical complex. However, there is a repetitive theme in the many plans which focuses on several vital requirements. A successful plan must express:
(a) A definition of objectives, i.e. project goals, desired end results with a schedule which measures achievement against time.

(b) Agreement on project execution philosophies.

(c) The general rules of the working relationship between the Client and the Managing Contractor.

(d) Responsibilities of both Managing Contractor and Client.

(e) The appointment of project leadership and the latitude of action by the Managing Contractor with regard to decisions and recommendations.

(f) Accountability for results.

A proven realistic approach to this task requires development of a general project plan divided into distinct activity stages. For purposes of illustration there are three (3) general periods, each of which will include dozens, if not hundreds of individual activities.

**Stage 1**

This encompasses all activities to be performed, or decisions to be made, from the start of work to placement of the last major contract for process or offsite units which should take place about 14 to 16 months later.

**Stage 2**

This stage covers the period when contractors are designing, procuring equipment and materials, and constructing process plants and major auxiliary units. The period extends from the pre contract phase up to completion of main construction work. An overall period of about 4 - 4½ years.

**Stage 3**

The period following successful start-up of final process plant and ancillary units - continuing throughout the following two years of operation of the total complex.
FIRST DETAILED PROJECT PLAN
(Tasks and priorities)

Stage 1

An experienced Managing Contractor will know that desired results can be achieved only if the general project plan is carefully followed with a fully detailed programme identifying priorities, and establishing the schedule necessary to move the project forward. This approach assures a rational progression and, the sense of order crucial to economic development and proper control of the project.

The scope of work encompasses building several process plants with all necessary supporting facilities such as power and water supply, effluent treatment, service roads and railroads and many others at the same time and for a common purpose. The divided ownership, financing, and construction responsibilities planned for the project in Thailand make the problems of project control and coordination even more difficult. Each stage of work must be reviewed at frequent intervals, and the detailed execution plan continuously updated to assure that job progress is maintained in spite of problems which will occur. It is a certainty that many problems will arise in spite of the best planned programme. However, experienced management will minimize the adverse effect of those which do occur.
The first detailed plan should recognise the numerous activities which, by early assessment between the Client and Managing Contractor, can be studied or conducted on a broad front. These include detailed investigation of site location, agreement on the number of process units to be included in the complex, their design capacities, fuel and water requirements and recognition of the general affect that such a vast facility will have in social, economic and environmental terms on the area of plant location. Liaison with other major industrial development currently in progress or in the planning stage in the affected area must be closely coordinated.

To determine the common needs of the process technologies, information must be obtained from licensors and process plant contractors. Data collected must be based on specific design criteria regarding process units to be built, or on actual experience of other operating plants, similar in size and design.

The process units should be studied and divided into groups involving related technologies. Ideally the groups of plants should be of relatively equal estimated value, or of such aggregate value as to attract aggressive, competitive bidding by international contractors or consortia with favourable pricing and financing from their worldwide sources.
Attention must be given at an early stage to development of that basic engineering data which may be common to all site facilities - engineering standards, specifications and procedures to govern overall project execution. All this information must be included in "Invitations to Bidders" to be sent to contractors selected to bid on the process units and the major utilities or infrastructure items. Careful attention must also be paid to this documentation to ensure clear communication to bidders of the quality and extent of work to be performed, and the responsibilities and procedures to be closely adhered to during several years of engineering, procurement, and construction activity.

Since process plant contracts may be placed on a firm, lump sum basis any oversight or deficiency in pre contract specifications may predictably result in substantial extra cost or a reduction in the quality of plants to be built. Also in fairness to the contractors who will spend several months and a great deal of money in the preparation of proposals, it is a Managing Contractor's responsibility to include in bid documents information of sufficient clarity to avoid confusion or ambiguity which would ultimately result in higher cost to the project owners.

To ensure that qualified contractors are attracted to compete for portions of the project, the work should be allocated in large contract packages to major companies of international stature. These companies, with many years of proven capability could be expected to provide financing assistance from their respective national sources or through international lending agencies.
The solicitation of bids, bid preparation and final bid evaluation requires many months of effort by the owner's representatives, the Managing Contractor and respondent bidders for construction of major facilities.

The project schedule should permit placement of all contracts within 14 to 16 months from the start of project planning. This is achievable and will assure overall completion within a reasonable schedule.

During the period of preparation of Invitations to Bid, a number of very important problems must be dealt with. These are:

Establishment of a coordination procedure to define precisely the extent and routing of communications among participating parties and any involved Governmental agencies. A system must also be developed in detail to ensure preparation, distribution, storage and retrieval of technical, commercial and financial documents.

Preliminary estimates of project costs must be prepared and numerous revisions made as more information becomes available. This serves to keep the project owners fully informed on a current basis and also provides advance knowledge necessary to evaluate project financing schemes submitted by contractors with their proposals. It provides a basis for consideration of supplementary financing from commercial sources if necessary.
Stage 2

COORDINATION

After placement of major process plant contracts and during the engineering and procurement phase of the contractor's work there are many activities demanding the full attention of the Managing Contractor.

At this time a basic design of the non-process facilities must be completed and contracts awarded for site preparation, drainage systems, roads, railroad facilities, water supply wells, water treatment and effluent systems including waste disposal. A power generating station must be constructed, with electrical distribution systems and arrangements made for a communications network linking the site location and client and contractor's offices. This communication system is vital to rapid and accurate transmittal of information from many sources to the Managing Contractor's office. Also a permanent record of essential information must be compiled.

Throughout the contract execution period the Managing Contractor's personnel must be stationed in other participating contractors' offices to monitor the progress and quality of work, to resolve questions between other parties and the contractors, and to coordinate the flow of contractor interface information to others for solution of field problems.
An important concern from the beginning will be the need for skilled personnel necessary to build, operate and maintain the petrochemical complex and its auxiliary units. Great attention must be directed to an appraisal of total manpower requirement for the job, and development of a very detailed programme to assure maximum utilisation and opportunities for Thai personnel. The programme should be initiated at the very beginning of the project and must continue beyond the operational start-up of the facility into the early years of plant operation. Several thousand men of many different trades and skills would be employed to build the plant. The operation and maintenance of the plant would provide up to 3,000 permanent employment positions for Thai men and women.

There must be an extensive and thorough personnel training programme. The scope of this assignment would cover the training of young Thai engineers or technical candidates stationed in various engineering offices or the offices of licensors and contractors. In these positions they will have an opportunity to learn about Project Management, engineering techniques, accounting and finance and scheduling, and the many other activities which take place in contractors' or licensors' offices, ultimately to be required in the operation and maintenance of the facility.
This part of the training programme would take place during the time that the plants are actually being designed and built by the contractors.

A major part of the programme should be directed to the development of those skills needed by craftsmen to construct the plant. The contractors who build the facilities should be required to use the highest degree of Thai labour available. It would be their responsibility to train the welders, pipe fitters, instrument technicians and other people needed for construction. Many of these construction personnel as well as the young engineers who have had training outside of Thailand should later form the operating and maintenance staff for the facility. These young trainees would be elevated to management status within the petrochemical complex as their experience and abilities increased.

The guiding theme throughout this training programme should be that Thai personnel must be given an opportunity to learn by actual experience, whether in a professional status or at a craftsman level. This should be a contractual requirement imposed upon all contractors participating in the job.

LABOUR POLICY

For a period of 3 years or more thousands of construction and supervisory personnel will be employed in a common congested area where a number of major contractors, and many sub contractors, will be at work on the different plants and offsite units. This positively
requires a project labour policy binding all contractors to common terms of employment and labour discipline. This is essential to the efficient use of labour resources and to avoidance of inequitable practices by contractors and, further to reduce cause for controversy between employers of labour on the project.

During construction of the plants the Managing Contractor must employ teams of personnel to monitor and coordinate the contractors in the field. They would have responsibility to overview the work, and control the inter-relationships of the various contractors who will be on the site at one time. You can appreciate that when five or six major contractors are working simultaneously in a common area it is extremely important that their activities be properly scheduled and coordinated to avoid confusion and misunderstanding. It will also be necessary to oversee the work from a quality and safety standpoint and to be sure that the construction progress adheres to the overall schedule, and that the units are finished in a prescribed sequence to meet the start-up schedule.

Activities at any given time will range from the placement of foundations and underground piping to the erection of complex machinery, materials handling systems, or large buildings and process equipment.

Precise schedules and movements of all contractors must be known well in advance and closely coordinated to avoid confusion, delay and increased cost.
One of the primary problems and responsibilities of the Managing Contractor is to organise and control common contractor needs such as roadways, temporary utilities, rail sidings and fabrication and materials storage areas. It will also be necessary to provide communication services, a security system, fire brigades, food catering, living accommodation and many other items. All of these needs must be studied and a detailed plan developed as part of the field control procedures. Each contractor must be informed of his role and how his needs will be met, and held to account in respect of the rights and needs of other contractors.

During construction the Managing Contractor should apply methods and procedures to assure full compliance with a Safety Plan. Procedures must be set for control and monitoring of work quality, job progress, and control of design or work scope changes.

STAGE 3

The construction phase will end with mechanical completion of each of the process units or major auxiliaries. This is the conclusion of all construction work for a specific process or system. It is important that mechanical completion of the various plants be correctly scheduled so that, as each unit is finished, it can be started-up and commissioned in correct relationship to the entire facility. Many of the units will be integrated so it would be pointless to complete one plant far ahead of the others. Immediately following completion, start-up and commissioning of operating units, performance tests will be conducted by the contractors and licensors involved. These must be monitored by the Managing
Contractor Project Team in the owners interest to ensure that all equipment, systems and plant meet the guaranteed product output and utilities consumption specified. This is a very critical and important part of the overall programme and must be diligently supervised and recorded before final payment to contractors.

After completion and testing, the plants will be formally accepted by their respective owners. Final acceptance should take place approximately one year after provisional acceptance. This ensures that any deficiencies undiscovered in the early stages of operation will have surfaced and been properly corrected.

Successful execution of the project depends on the effective coordination and monitoring of all work involved. This is a task which can only be carried out by someone authorised to make the relevant decisions when they need to be made - someone who possesses sufficient experience and proficiency to ensure that those decisions are the right ones. The need for such a controlling authority cannot be over emphasised if the project is to be completed within budget, on schedule and in fulfillment of the goals and expectations of those people willing to make this major investment in Thailand.

If all goes according to plan, within 4½ to 5 years from start of work you could have a full-scale, operational, modern petrochemical complex to serve your needs for the rest of this century and beyond.
Gentlemen - thank you. Now, if there are any questions which you may have regarding the subjects I have touched on, I will be glad to try and answer them.
OLEFINS FOR THAILAND
ETHANE-PROPANE CRACKING
TECHNOLOGY

by

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NATURAL GAS UTILIZATION
SYMPOSIUM
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STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASSACHUSETTS
1.0 INTRODUCTION

Previous studies to upgrade the Thai natural gas resources to petrochemicals have already identified many of the key objectives and considerations involved in this major national program. One vital decision which has an impact on the ultimate profitability of this project is that of technology selection. The cornerstone of the National Petrochemical Company (NPC) Complex will be the olefin production unit. It is vital that this component of the project be based on the most efficient and reliable process technology. This presentation will discuss those process features which distinguish the available olefin production technologies, with particular respect to the pyrolysis system selection. This selection is influenced considerably by propylene coproduct production requirements. Finally, reference will be made to the role of the technology licensor in providing financial, technical and operational support to the new owners.
2.0 SPECIFIC NATIONAL PETROCHEMICAL COMPANY REQUIREMENTS

Data provided in NPC and Eastern Seaboard Development Inc. publications have defined the basic feedstock utilization product requirements and basic energy philosophies to be employed. Specifically the relative propylene : ethylene production ratios are to be met from restricted amounts of propane feedstock, ethane feedstock being priced at a relative discount. Cracking selectivity and flexibility thus are of prime importance.

The indicated plant fuel value and the requirement to select an economic compromise between investment and operating cost encourages the olefin unit designer to employ relatively efficient technology. In all the above objectives, i.e., selectivity, flexibility and efficiency, the application of integration techniques will yield important benefits.

Implicit in this project is the absolute requirement for process reliability. Furthermore, adequate coordination, training and post-commissioning support will be necessary to ensure that this project yields the highest return to Thailand in terms of petrochemical self-sufficiency, return on investment, and advancement of industrialization.

As a leader in olefin technology, having designed the majority of Asian olefin units - most recently that for the Petrochemical Corporation of Singapore - Stone & Webster (S&W) has the highest qualifications in the field of olefin technology. The specific features of this technology applicable to the NPC Project will be presented.
3.0 OLEFIN TECHNOLOGY TRENDS

The current industry problems and impending changes in world petrochemical trade patterns have been well publicized. As the prime component of the petrochemical sector, much interest has thus been focused on olefin production. Although mature, this technology still has important areas of technical differentiation. S&W, as a major supplier of this technology, continues to make significant improvements, particularly in the key area of pyrolysis.

Analysis of the variable cost elements of olefin production demonstrates clearly why the pyrolysis system basically controls olefin economics (see attached table). Feedstock cost is the largest single cost component - hence high cracking selectivity to maximize olefin yield and minimize feedstock consumption is of paramount importance. Energy costs represent a considerable portion of overall production cost; again, since it is the predominant plant energy consumer, the pyrolysis/quench area of the plant will basically determine energy costs. Most operators now recognize the pyrolysis/quench systems as the major source of maintenance problems; S&W cracking furnaces have been retrofitted in several earlier non-S&W plants where the false economy of low cost but inadequate equipment resulted in low furnace area availability and increasing maintenance costs.

The olefin plant recovery system is undoubtedly an important item in overall process performance. In this area of technology one may indeed recognize design maturity. Various combinations of the basic fractionation and other unit operations have been practiced. Earlier S&W designs employed front-end depropanizer systems; current S&W designs are based on front-end demethanizer systems; other licensors favor front-end deethanization. The
S&W recovery system design has evolved from the construction of some 100 olefin processing facilities. Extensive improvements in the cold fractionation area have reduced this energy component by some 50 percent in recent years. While further reduction is still possible, thermodynamic constraints and cost effectiveness considerations limit major improvements. Moreover, this portion of the overall plant energy consumption is already overshadowed by that of the pyrolysis/quench system.

S&W emphasizes the importance of correct energy system selection in the olefin unit. The application of advanced energy economics has contributed significantly to the efficiency of the modern S&W pyrolysis system. In this respect, integration of the olefin unit within the complex pays major dividends. S&W has pioneered the application of gas turbine integration in the olefin unit; based on the design and operating experience gained from some 80 gas turbine installations, S&W has adapted this advanced cogeneration principle to the olefin unit without compromising plant reliability.

Most new S&W olefin units are equipped with microprocessor based distributed control systems plus various levels of supervisory and optimizing control. The advanced computer control software supplied with the S&W unit has further enhanced the overall process efficiency. The off-line plant simulation training facilities offered by this system are of particular benefit to the new operator.
The cracking furnace designer attempts to maximize return on investment by balancing investment, yield, and energy consumption. Within these general constraints, various technical approaches have evolved. Current ethane-propane cracking technology may be categorized into two basic design philosophies linked primarily to the diameters of the cracking coil and the downstream quench exchanger tubes. S&W's design is based on a 2 to 3-inch ID coil combined with a 4 to 5-inch ID exchanger. In order to avoid infringement of S&W patents, other cracking furnace designers have adopted larger diameter coils (4 to 6-inch mean ID) combined with shell and tube type quench exchangers where the tube diameter is typically 1.75 inch or less.

These basic design differences translate into important overall yield and run length advantages for the S&W design. Students of cracking technology are aware of the inevitable relationships between coil diameter, residence time, and yield. Likewise, the importance of quench exchanger design on coking rates, coil backpressure, and hydrocarbon partial pressure is now recognized throughout the industry. S&W has developed a rigorous finite analysis technique to accurately predict all hydraulic, thermal and kinetic interactive effects within the pyrolysis system. This computerized design method allows the optimization of the system design by considering operation for start-of-run to end-of-run conditions.

The design conclusions which emerge from this analysis for ethane-propane cracking show that the optimum coil selectivity: capacity ratio favors a residence time/partial pressure combination as offered by the medium diameter, swaged W type coil in combination with the proprietary USX quench exchanger.
This exchanger type has been found to be particularly effective for ethane-propane cracking; its simple mechanical design avoids the problem of tube sheet coking which plagues the shell and tube type quench exchanger. This progressive fouling of the shell and tube type quench exchanger results in a marked deterioration in ethylene yield (up to 3% wt on feed) over an acceptable operating cycle. In fact, it is this problem of exchanger tube sheet coking which invariably causes premature termination of the operating cycle for non-S&W designs.
5.0 PYROLYSIS SYSTEM ECONOMICS

The computerized design model described above has been used to compare the yield performance of the S&W pyrolysis system vs. that of the alternative coil-exchanger combination as proposed by others. Representative feed and product values for the NPC project have been applied in order to calculate net product revenue (NPR), defined as value of total products minus cost of feed.

The selectivity advantage offered by the S&W system, which becomes successively greater as the operating cycle proceeds, due to the exchanger fouling characteristics described above, translates into an approximately $3 million per year higher NPR.
6.0 THERMAL EFFICIENCY

Current cracking furnace designs have responded to increasing energy costs and have reduced heat losses to less than 5 percent of total fired heat. In this respect, computerized combustion control has made an important contribution. Having thus reduced conventional energy loss from the cracking system - stack temperatures are now limited by carbonic acid condensation, i.e., less than 100°C, the designer has sought to maximize the high level heat recovery from the system.

S&W has made extensive analyses of energy system optimization within the olefins unit; application of power generation principles (S&W is a major engineering contractor for power generation facilities) has contributed important energy economies within the olefins plant steam system.

The principle of gas turbine integration within the olefins unit has been extended to further reduce overall energy consumption. A new cracking furnace layout has been developed to accommodate either Gas Turbine Integration (GTI) or Combustion Air Preheat (CAP); incorporation of GTI within the unit has also resulted in changes in main train compressor driver philosophy. The selection of GTI or CAP should be part of the optimization of overall energy systems for the complex, taking into consideration the electric power and steam requirements of all the consumers and the supply/demand flexibility thereof.
7.0 PROPYLENE COPRODUCT PRODUCTION

The NPC project prospectus calls for a propylene demand which cannot be met by conventional cracking of the designated amounts of ethane and propane feedstock. In order to attain this propylene production level, various other processing schemes have been evaluated, although the detailed results are not included in this paper. These include lower conversion propane cracking, feedstock slate adjustment to include heavier available feeds, propane dehydrogenation, and recombination cracking. This latter process involves conversion of the ethane feedstock into higher molecular weight precursors for subsequent cracking to the desired propylene:ethylene production levels.

The relative viability and economics of the above systems have been tested on the basis of feed and product values developed from quoted guidelines. The final selection of the preferred route will depend largely upon relative feedstock pricing and availability. Only when propane value approaches twice that of ethane can the nonconventional process options be economically justified.

Should propane dehydrogenation be selected for the NPC project, serious consideration should be given to the process integration aspects. S&W has developed schemes whereby the large amounts of reaction heat required by the process can be supplied in conjunction with the conventional ethane cracking process energy requirements. Such rationalization of energy allocation can result in significant overall energy and investment savings.
8.0 TECHNOLOGY LICENSOR'S ROLE

Although the principal role of the technology supplier is to ensure the successful implementation of its technology in the project, its services should ideally extend beyond this somewhat narrow scope. Particularly where a new owner is involved, the support which the technology licensor should supply has a far-reaching influence on the ultimate success of the project.

S&W offers a complete range of services to the client to provide sound advice and assistance prior to the actual engineering/procurement/construction effort; these include project appraisal, marketing surveys, site selection, environmental analysis and project financing assistance.

During the construction phase there are several important parallel activities devoted particularly to technology transfer and staff training at various levels within the client's organization. Client engineers are encouraged to participate in the S&W home-office design phase in order to ensure maximum exposure to the process technology. S&W has developed simulation systems linked to the plant computer control system which allow "hands-on" operator training prior to actual plant startup. Arrangements are frequently made with other S&W licensees to allow on-the-job training of plant staff from the new licensee company under S&W supervision.

The licensor obviously must provide high level commissioning support to the new owner. The degree of assistance will vary with specific client circumstances; S&W has provided support ranging from simple advisory assistance up to full manning of the site operations. For the NPC project, it is anticipated that a relatively comprehensive initial support program would be appropriate, reducing thereafter as operator experience and confidence increases.
Associated areas where the licensor should also contribute assistance include organization of the site maintenance program, including a computerized spare parts management system, establishing the necessary laboratory facilities, providing recommendations to the administrative and technical branches of the client's organization and ensuring prompt response to his requests for backup from equipment suppliers. The familiarity of the S&W organization with all of the above tasks and the recent experience in several major ASEAN projects will be available to assist NPC in their most important project.
# TABLE I

**ETHANE CRACKING ECONOMICS**

**Basis:** 300,000 MTA ethylene from ethane at 60% conversion

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISEL Investment, mm$</td>
<td>150.00</td>
</tr>
<tr>
<td>Equity</td>
<td>30 per cent</td>
</tr>
<tr>
<td>Financed</td>
<td>70 per cent</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Material Balance</th>
<th>MTA /MT mm $/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed</td>
<td>375</td>
</tr>
<tr>
<td>Fuel Gas</td>
<td>49</td>
</tr>
<tr>
<td>Ethylene</td>
<td>300</td>
</tr>
<tr>
<td>Fuel Liquid</td>
<td>76</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Utilities</th>
<th>units/unit/MT $/unit mm $/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel</td>
<td>3.13 10.70 10.02</td>
</tr>
<tr>
<td>Power</td>
<td>75.24 0.05 0.02</td>
</tr>
<tr>
<td>BFW</td>
<td>8.40 0.60 1.51</td>
</tr>
<tr>
<td>Cat/chem</td>
<td>0.54</td>
</tr>
</tbody>
</table>

| Total Utilities               | 14.15               |

<table>
<thead>
<tr>
<th>Operating Costs</th>
<th>man-yr $/man-yr mm$/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor</td>
<td>100 4000 0.40</td>
</tr>
<tr>
<td>Supervision</td>
<td>10 8000 0.08</td>
</tr>
<tr>
<td>Maintenance</td>
<td>2% ISEL 2.10</td>
</tr>
</tbody>
</table>

| Total Operating Costs         | 3.68                 |

<table>
<thead>
<tr>
<th>Fixed Costs</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Overhead</td>
<td>30% L &amp; S 0.14</td>
</tr>
<tr>
<td>Genl Plant Ovhd</td>
<td>40% Maint 1.92</td>
</tr>
<tr>
<td>Insurance</td>
<td>2% ISEL 2.20</td>
</tr>
<tr>
<td>Depreciation</td>
<td>10% ISEL 16.00</td>
</tr>
<tr>
<td>Interest</td>
<td>10% Financed 11.50</td>
</tr>
<tr>
<td>Return</td>
<td>25% Equity 12.00</td>
</tr>
</tbody>
</table>

| Total Fixed Costs            | 64.46                 |

<table>
<thead>
<tr>
<th>Ethylene Production Costs</th>
<th>mm$/yr $/MT per cent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Feed Cost</td>
<td>46.88 117 40</td>
</tr>
<tr>
<td>Energy</td>
<td>14.15 35 12</td>
</tr>
<tr>
<td>Capital</td>
<td>55.02 140 48</td>
</tr>
</tbody>
</table>

| Total                        | 116.05 227 100         |

<table>
<thead>
<tr>
<th>Net Feed Cost</th>
<th>mm$/yr $/MT per cent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>14.15 35 14</td>
</tr>
<tr>
<td>Capital</td>
<td>55.02 140 54</td>
</tr>
</tbody>
</table>

| Total                        | 104.19 260 100         |
OLEFIN PRODUCTION COSTS

BASIS:
PROJECTED THAI COSTS

CAPITAL 54

32 NET FEEDSTOCK

ENERGY 14

CAPITAL 48

ENERGY 12

GROSS FEEDSTOCK 40
ENERGY DISTRIBUTION - E/P CRACKING

- PYROLYSIS & QUENCH: 105
- C-G COMPSN: 28
- FRACTN: 30
- ISBL UTILITIES: 9
- TOTAL: 175
- NET: 100
## KEY PYROLYSIS SYSTEM DIMENSIONS

<table>
<thead>
<tr>
<th></th>
<th>S&amp;W</th>
<th>OTHERS</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRACKING COIL</td>
<td>SMALL</td>
<td>LARGE</td>
</tr>
<tr>
<td>MEAN INTERNAL DIAMETER</td>
<td>2-3 INS</td>
<td>4-6 INS</td>
</tr>
<tr>
<td>QUENCH EXCHANGER</td>
<td>LARGE</td>
<td>SMALL</td>
</tr>
<tr>
<td>TUBE INTERNAL DIAMETER</td>
<td>4.5-5.5 INS</td>
<td>1.25-1.75 INS</td>
</tr>
</tbody>
</table>

COVERED BY PATENTS
## PYROLYSIS SYSTEM ECONOMICS

<table>
<thead>
<tr>
<th></th>
<th>S&amp;W</th>
<th>OTHERS</th>
</tr>
</thead>
<tbody>
<tr>
<td>COIL OUTLET PRESSURE, SOR (kg/cm²)</td>
<td>BASE</td>
<td>BASE</td>
</tr>
<tr>
<td>Δ PRESSURE INCREASE, EOR (kg/cm²)</td>
<td>0.22</td>
<td>0.40</td>
</tr>
<tr>
<td>Δ YIELD, SOR-EOR (% wt C₂H₄ on feed)</td>
<td>0.97</td>
<td>2.64</td>
</tr>
<tr>
<td>NET PRODUCT REVENUE, EOR (MM$)</td>
<td>134.2</td>
<td>131.4</td>
</tr>
</tbody>
</table>

**BASIS: 350,000 MTA ETHANE FEED**

**REPRESENTATIVE FEED & PRODUCT VALUES**
USC ADVANTAGE (NPR)

- ETHANE
- PROPANE

MM$/YR

CLEAN

FOULED
MAXIMIZE PROPYLENE (E, P)

% CONVERSION

ULTIMATE YIELD WT %

PROPAINE

ETHANE

0.6

1.6

29

15
MAXIMIZE PROPYLENE
(LOW & HIGH CONVERSION)

\[ \begin{array}{c|c}
\text{C}_3 & 15  \\
\text{NC}_4 & 12  \\
\text{IC}_4 & 16  \\
\text{NGL} & 16  \\
\end{array} \]
The diagram illustrates the relationship between net product revenue investment and the propane/ethane price ratio. It shows a linear relationship where the investment decreases as the price ratio increases. The graph is labeled with two regions: 'Segregated Cracking' and 'Dehydro', indicating different operational modes or processes based on the price ratio.
Production and Economics of Olefins from Ethane and LPG

by
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Manager of Olefins Development
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Presented at the
Thailand – United States
Natural Gas Utilization Symposium
Bangkok, Thailand
February 9, 1984
ABSTRACT

Thailand wishes to produce ethylene and a relatively high proportion of propylene from limited indigenous supplies of ethane, propane and C₄ LPG. It may not be feasible or economic to produce the high proportion of propylene desired by steam pyrolysis alone. Additional propylene can be produced by propane dehydrogenation. The recovery of propylene from the dehydrogenation reactor can be done separately, or together with the pyrolysis effluent.

This paper discusses and compares the various options for optimizing the utilization of Thailand's feedstocks to produce the desired olefins with due consideration to pricing structure sensitivity, and recommends the optimum selection for Thailand's conditions.
Thailand has limited quantities of indigenous ethane, propane, and C4 LPG feedstocks, which they are interested in using to produce polymer-grade ethylene and polymer-grade propylene at the rates shown in Table 1. These olefins will be used as feedstocks to a petrochemical complex, which tentatively will produce polyethylene, vinyl chloride, ethylene glycol, and polypropylene.

### Products Required

<table>
<thead>
<tr>
<th></th>
<th>MTY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethylene</td>
<td>261,000</td>
</tr>
<tr>
<td>Propylene</td>
<td>73,000</td>
</tr>
</tbody>
</table>

**Table 1**

The available feedstocks are described in Table 2. The total available quantities are 350,000 mty ethane, 217,000 mty propane, and 240,000 mty C4 LPG. Of these, all the ethane and 130,000 mty of the propane have been allocated tentatively for olefins production. We assume in this paper that additional propane and C4 LPG feed can be used if justification against competing uses of these materials can be demonstrated.

### Feedstocks, Wt%

<table>
<thead>
<tr>
<th>Component</th>
<th>Ethane</th>
<th>Propane</th>
<th>C4 LPG</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2</td>
<td>5.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methane</td>
<td>1.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ethane</td>
<td>91.9</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>Propane</td>
<td>2.1</td>
<td>99.5</td>
<td>30.1</td>
</tr>
<tr>
<td>Iso Butane</td>
<td>0.4</td>
<td></td>
<td>36.8</td>
</tr>
<tr>
<td>N-Butane</td>
<td></td>
<td></td>
<td>32.4</td>
</tr>
<tr>
<td>C5's</td>
<td></td>
<td></td>
<td>0.7</td>
</tr>
<tr>
<td>Total</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
<tr>
<td>MTY Total</td>
<td>350,000</td>
<td>217,000</td>
<td>240,000</td>
</tr>
<tr>
<td>Available</td>
<td>350,000</td>
<td>130,000</td>
<td>(?)</td>
</tr>
</tbody>
</table>

**Table 2**
OPTIONS  The conventional technology for producing ethylene is steam pyrolysis of hydrocarbons. The typical high severity conditions for producing ethylene from ethane and propane are summarized in Table 3.

<table>
<thead>
<tr>
<th>Conventional High Severity Pyrolysis Conditions</th>
<th>Ethane</th>
<th>Propane</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conversion Level, %</td>
<td>60</td>
<td>93</td>
</tr>
<tr>
<td>Ultimate Yield, WT%</td>
<td>80</td>
<td>43</td>
</tr>
<tr>
<td>Ethylene</td>
<td>2</td>
<td>14</td>
</tr>
<tr>
<td>Propylene</td>
<td>329*</td>
<td>130</td>
</tr>
<tr>
<td>Available Feed, MTY</td>
<td>217</td>
<td></td>
</tr>
<tr>
<td>Ethylene Potential, MTY</td>
<td>261</td>
<td>56</td>
</tr>
<tr>
<td>% of Required</td>
<td>93</td>
<td></td>
</tr>
<tr>
<td>Propylene Potential, MTY</td>
<td>100</td>
<td>21</td>
</tr>
<tr>
<td>% of Required</td>
<td>36</td>
<td></td>
</tr>
<tr>
<td>CH₄ &amp; CO₂</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 3

The per-pass conversions as percent of feed are 60 for ethane and 93 for propane. Ethane yields about 80 weight percent ethylene, but very little propylene -- about 2 percent. As can be seen from this table, there is enough ethane available to produce all of the required ethylene, but only about 10 percent of the required propylene. Therefore, essentially all of the propylene has to be provided from propane and other feedstocks.

Propane yields about 43 percent ethylene and about 14 percent propylene when ethane and propane are recycled to extinction. If the propane feed availability is limited to 130,000 mty, it can produce only about 25 percent of the required propylene. If all 217,000 mty of propane is used, the propylene potential increases to some 41 percent of the required amount, still not enough to meet the desired propylene production.

Therefore, in order to meet the relatively high propylene production target, we have to resort to means and technologies other than conventional high severity pyrolysis of ethane and propane.

Several options are available. The yield of propylene from propane can be increased by lowering the cracking severity. Supplemental C₄ LPG can be used, and also cracked at low severity to further enhance propylene yield. Propane dehydrogenation yields about 83 weight percent propylene on feed. Therefore, it is an excellent option for satisfying propylene production. The options shown in Table 4 are evaluated in this paper.
Options for Propylene Production

Crack Propane up to Maximum Availability at Low Severity
Supplement Propane with C4 LPG and Co-crack with Propane
Dehydrogenate Propane
CASES

The following cases are compared in this paper.

CASE 1 Case 1 is shown schematically in Figure 1.

In Case 1, the required ethylene and propylene are produced by pyrolysis of ethane and propane exclusively, without the need for propane dehydrogenation. The preliminary propane allocation of 130,000 mty is not adequate to produce the required propylene. The maximum available quantity of 217,000 mty of propane has to be used.

Almost all of the propylene is produced by low-severity cracking of propane, and the balance of the ethylene is produced by high-severity pyrolysis of ethane in separate furnaces and as needed. Ethane is recycled to the ethane furnaces, and propane to the propane furnaces.
Case 2 is shown schematically in Figure 2.

Case 2
Co-Crack C\textsubscript{3} and C\textsubscript{4}
Crack C\textsubscript{2} as Needed

Co-crack at Low Severity 130,000 MTY C\textsubscript{3}H\textsubscript{8}
with C\textsubscript{4}-LPG to Produce Propylene
Crack Ethane at High Severity to Balance Ethylene

Figure 2

Case 2 is similar to Case 1, but only the preliminary allocation of propane feed is cracked. The balance of propylene is produced by co-cracking C\textsubscript{4} LPG with the propane at low severity. Ethane is cracked separately at high severity and as needed to produce the balance of the ethylene product.
CASE 3  Case 3 is shown schematically in Figure 3.

In Case 3, the required ethylene and propylene are produced without exceeding the preliminary allocations of ethane and propane given in Table 1, namely 350,000 mty of ethane, (332,000 on CO₂-free basis), and 130,000 mty of propane.

In this case, the available propane is not adequate to produce the required propylene product by cracking alone. Therefore, the propylene is produced by catalytic dehydrogenation of propane in a licensed propane dehydrogenation unit (PDU). The ethylene is produced by high severity pyrolysis of ethane, Due to the high yield of propylene from propane dehydrogenation, only about 81,000 mty of propane feed is required, and 324,000 mty of ethane on a CO₂-free basis is required to produce the ethylene.

The PDU is integrated with the ethylene plant, and the propane and ethane are recycled to extinction in the PDU and the ethane furnaces, respectively.

Propane dehydrogenation has not been practiced commercially. A plant has been released for construction recently, and equipment is being purchased. There is considerable related commercial experience with butane dehydrogenation to produce butenes or butadiene using the same technology. We believe the combination of the commercial experience with butane and adequate pilot plant backup with both butane and propane dehydrogenation provides an adequate basis for the technical feasibility of the process.

Figure 3
PROCESS DESCRIPTION

In Cases 1 and 2, all of the ethylene and propylene is produced by cracking. In Case 3, all of the ethylene is produced from ethane cracking and almost all of the propylene from propane dehydrogenation. As will be discussed later in this paper, in order to avoid uneconomical duplication of equipment and to minimize feedstock consumption in Case 3, the dehydrogenation reactor effluent is combined with the cracker effluent and processed in integrated recovery facilities. The pros and cons of integrated versus separate units for Case 3 are also discussed in the last section of this paper.

By-products in all cases include a hydrogen-rich tail gas, mixed C4's, raw gasoline, and fuel oil. These are all consumed in the plant as fuel or exported as fuel products. Ethane and propane are recycled to extinction.

Following is a brief description of the process schemes.

CASE 1 PROCESS DESCRIPTION The Case 1 process flow scheme is shown in Figure 4.

Fresh ethane feed is treated in a monoethanolamine (MEA) unit to remove CO2. Treated ethane feed is combined with ethane recycle, and is cracked in separate furnaces at high severity.

The fresh propane feed is combined with propane recycle and cracked in separate furnaces at unconventionally low severity of 56 percent conversion per pass. As will be explained under Yields, this low severity is necessary in order to produce the required propylene. Compared to Case 3, less ethane needs to be cracked, because some of the ethylene is produced from propane.
The furnace effluents are cooled in transfer line exchangers (TLE's) to generate high pressure steam, then combined and further cooled by direct water quench in the water wash tower. The cracked gas is then compressed, caustic-washed to remove traces of acid gas, and dried before entering the fractionation section.

The fractionation sequence for the recovery of ethylene is a deethanizer-demethanizer-C2 splitter. This is referred to as a front-end deethanizer plant. For ethylene plants processing ethane and propane feedstocks, this sequence is optimum because, as reported in a recent Braun paper(1), it saves both capital and energy compared to a conventional front-end demethanizer plant.

The overhead vapor from the deethanizer contains ethane and lighter components, which are further compressed and sent to the acetylene hydrogenation reactor to convert the acetylene. Any "green oil" that may be produced in the reactor is recycled to the deethanizer, and thus fouling or freezing problems are eliminated from the downstream C2 and lighter circuit.

The net deethanizer overhead is chilled in multiple stages, and the liquid and vapor produced are sent to the demethanizer and cold box for recovery of the C2's and for the removal of hydrogen and methane as tail gas.

The demethanizer bottoms flow to the C2 splitter, where the ethylene product and ethane recycle are produced. A special design of a low-pressure C2 splitter, heat-pumped with the ethylene compressor, is used. This system is described in a recent Braun paper(2), and it saves both capital and energy compared to a conventional high pressure splitter.

The net deethanizer bottoms are sent to a depropanizer. The mixed C3's from the depropanizer overhead are fractionated in a C3 splitter to yield polymer-grade propylene and a propane recycle. The depropanizer bottoms is fed to the debutanizer which produces a mixed C4'i; overhead product and a raw gasoline bottoms product.

In addition to its economic advantage, this scheme has several important process advantages compared to the conventional front-end demethanizer system, as discussed previously(1). These advantages stem from the way acetylene is removed in a reactor located in the overhead loop of the deethanizer and upstream of the demethanizer.

Any "green oil" produced in the reactor is recycled to the deethanizer. Therefore, there are no fouling or hydrate problems downstream of the reactor. And, unlike the conventional system with a back-end acetylene reactor, there is no need for injecting hydrogen or carbon monoxide upstream of the C2 splitter, or methanol into the splitter. Therefore, the quality of the ethylene product is ensured on a continuous basis, and it is superior to that of the conventional system.
CASE 1 - PROCESS DESCRIPTION Continued

Assured and consistent ethylene quality should be of particular interest and importance to Thailand, in view of the fact that all of the downstream ethylene consumers will depend on this source for their feedstock.

CASE 2 PROCESS DESCRIPTION The flow scheme for Case 2 is identical to that of Case 1. The only exception is that C4 LPG is used as supplemental feedstock and is co-cracked with the propane at low severity. The reason for co-cracking at low severity is explained under Yields.

CASE 3 The Case 3 process flow scheme is shown in Figure 5. It is the same as that of Case 1, except propane cracking is replaced by propane dehydrogenation.

Fresh propane feedstock combines with propane recycle and is fed to a Propane Dehydrogenation Unit (PDU). After refrigeration is recovered from the combined stream, it is preheated and fed to the propane dehydrogenation reactor. The dehydrogenation reactor operates under vacuum, and the reactor effluent is cooled and compressed in a two-stage compressor to a pressure sufficiently high to admit this effluent into the water wash tower. There, it combines with the ethane cracking furnace effluent.
YIELDS

As discussed earlier and shown in Table 3, it is not possible to produce the required ethylene and propylene at the required proportions from the available ethane and propane feedstocks by conventional high-severity pyrolysis. But it is possible to do so, as was done in Cases 1 and 2, by cracking propane and C₄ LPG at lower severities. The reason for this becomes apparent from Figures 6, and 7.

![Ultimate Ethylene Yield vs Conversion](image)

Figure 6

![Ultimate Propylene Yield](image)

Figure 7
Figure 6 shows how the ultimate yield of ethylene varies with conversion of ethane, propane, n-butane, and iso-butane, respectively. Ethane and propane are recycled to extinction.

Figure 7 is a plot of ultimate propylene yield from ethane, propane, n-butane, and iso-butane, respectively, with ethane and propane recycled to extinction.

The yield of propylene from ethane is insignificant compared to that from the heavier feeds, and is slightly reduced as conversion of ethane is decreased. Therefore, there is no incentive to crack ethane at lower conversions.

The ultimate yield of propylene from propane keeps increasing as the conversion of propane decreases, even though the once-through yield peaks at about 70 percent. This is so because unconverted propane is recycled to extinction. Based on this phenomenon, it is possible to achieve the desired production of propylene in Case 1 by dropping the conversion of propane to about 56 percent.

Unlike propane, the ultimate yields of propylene from iso and normal butane peak at about the same conversion as their corresponding once-through yields, namely about 80 percent. The reason for this is that unconverted butanes are not recycled to extinction, while propane is.

CONVERSION LEVELS Table 5 shows the conversion levels selected in this study for the three cases.

<table>
<thead>
<tr>
<th>Conversion Level, % on Feed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed</td>
</tr>
<tr>
<td>Ethane</td>
</tr>
<tr>
<td>Propane</td>
</tr>
<tr>
<td>N-Butane</td>
</tr>
<tr>
<td>l-Butane</td>
</tr>
</tbody>
</table>

Table 5
YIELDS Continued

As explained above, for Case 1, a 56 percent conversion of propane is required to meet the propylene production. In Case 2, the selected conversion of 85 percent for n-butane and 75 percent for iso-butane are those occurring if the butanes are co-cracked with propane which is cracked at 56 percent. Since these butane conversions happen to coincide with the peak propylene yields, they appear to be the logical choice.

OVERALL MATERIAL BALANCE Overall material balances for each case are shown in Table 6 with ethane feed on a CO₂-free basis. The yield of propylene from ethane cracking is very small, about 5500 mty for this size plant if all the available ethane is cracked, as in Case 3. Most of the propylene is therefore produced by propane cracking in Case 1, by propane/butane cracking in Case 2, and by propane dehydrogenation in Case 3. To maximize propylene production, ethane is cracked separately at high severity in all cases, and propane and butane are cracked at low severity in separate furnaces in Cases 1 and 2.

Overall Material Balance

<table>
<thead>
<tr>
<th>Feeds</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>*Ethane</td>
<td>229.2</td>
<td>238.0</td>
<td>323.8</td>
</tr>
<tr>
<td>Propane</td>
<td>217.2</td>
<td>130.0</td>
<td>81.4</td>
</tr>
<tr>
<td>C₄-LPG</td>
<td>-</td>
<td>124.0</td>
<td>-</td>
</tr>
<tr>
<td>Water</td>
<td>2.1</td>
<td>2.5</td>
<td>1.5</td>
</tr>
<tr>
<td>Total</td>
<td>448.5</td>
<td>494.5</td>
<td>406.7</td>
</tr>
</tbody>
</table>

*CO₂ free basis

<table>
<thead>
<tr>
<th>Products</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tail Gas</td>
<td>91.2</td>
<td>122.4</td>
<td>56.7</td>
</tr>
<tr>
<td>Acid Gas</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Ethylene</td>
<td>261.0</td>
<td>261.0</td>
<td>261.0</td>
</tr>
<tr>
<td>Propylene</td>
<td>73.0</td>
<td>73.0</td>
<td>73.0</td>
</tr>
<tr>
<td>Mixed C₄'s</td>
<td>13.7</td>
<td>32.0</td>
<td>8.4</td>
</tr>
<tr>
<td>Gasoline</td>
<td>8.9</td>
<td>5.0</td>
<td>5.7</td>
</tr>
<tr>
<td>Fuel Oil</td>
<td>0.6</td>
<td>1.0</td>
<td>0.1</td>
</tr>
<tr>
<td>Coke Loss</td>
<td>-</td>
<td>-</td>
<td>1.7</td>
</tr>
<tr>
<td>Total</td>
<td>448.5</td>
<td>494.5</td>
<td>406.7</td>
</tr>
</tbody>
</table>

Table 6
COMPARISON OF CASES

In this section we compare the relative economics of Cases 1 through 3.

PRICING PREMISES  For the purposes of this paper, the pricing premises of Table 7 are used to establish a pricing structure for mid-1983 Thailand conditions.

<table>
<thead>
<tr>
<th>Pricing Premises For Mid-1983 Thailand Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethane</td>
</tr>
<tr>
<td>Propane</td>
</tr>
<tr>
<td>Butane</td>
</tr>
<tr>
<td>Fuel</td>
</tr>
<tr>
<td>By-products</td>
</tr>
</tbody>
</table>

Table 7

The rationale for these premises is as follows.

ETHANE  Ethane cannot be exported from Thailand or imported to Thailand in an economic way, because it is expensive to transport. Therefore, ethane that is not utilized for feedstock in Thailand should have fuel value. As feed, it is priced on the basis of 2.00 dollars per million BTU (HHV) for fuel gas plus one cent per pound to compensate for the cost of recovery from the natural gas.

PROPALE AND C₄ LPG  Propane and C₄ LPG can be used effectively in Thailand as domestic LPG fuel, and thus should be highly valued. Any use of these materials as feedstock would have to compete against their alternative use as LPG fuel. Therefore, we assumed them to be the same as propane and C₄ LPG, delivered from the Arabian Gulf. The delivered cost for this LPG was assumed to be 350 dollars per metric ton.

MIXED C₄ BY-PRODUCT  For the small quantity of mixed C₄ by-product that is produced, it is doubtful that further processing in Thailand can be justified, or that it can be exported economically. Therefore, we valued this by-product as fuel.
PRICING PREMISES Continued

RAW GASOLINE Raw gasoline by-product should be priced as fuel for the same reasons as C4 by-product.

PRICING STRUCTURE Based on the above premises, the pricing structure shown in Table 8 was established and used for the economic comparisons presented in this paper. It is based on mid-1983 conditions. The table includes two pricing structures, one for US Gulf Coast conditions, and one for Thailand conditions. The comparisons are carried out for both structures to test the sensitivity of the results to widely different pricing bases.

<table>
<thead>
<tr>
<th>Pricing Structure</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>1983 U.S. Dollars</strong></td>
</tr>
<tr>
<td><strong>Fuel (LHV)</strong></td>
</tr>
<tr>
<td><strong>Ethane Feed</strong></td>
</tr>
<tr>
<td><strong>Propane Feed</strong></td>
</tr>
<tr>
<td><strong>Electricity</strong></td>
</tr>
<tr>
<td><strong>Cooling Water</strong></td>
</tr>
<tr>
<td><strong>Boiler Feed Water Makeup</strong></td>
</tr>
<tr>
<td><strong>Condensate Export</strong></td>
</tr>
<tr>
<td><strong>40 Kg/cm² Steam</strong></td>
</tr>
<tr>
<td><strong>11 Kg/cm² Steam</strong></td>
</tr>
<tr>
<td><strong>3.5 Kg/cm² Steam</strong></td>
</tr>
</tbody>
</table>

Table 8

CASE 2 EVALUATION Table 9 compares the net raw material cost of Case 2 to Case 3, using the Thailand price structure from Table 8.

<table>
<thead>
<tr>
<th>Net Raw Material Comparison *</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Case 3</strong></td>
</tr>
<tr>
<td><strong>Case 2</strong></td>
</tr>
<tr>
<td><strong>Feedstock - By-products</strong></td>
</tr>
<tr>
<td><strong>Incremental Cost</strong></td>
</tr>
</tbody>
</table>

*Premises
- Ethane feed - $122/MT
- Propane feed - $350/MT
- C4-LPG feed - $350/MT
- By-products as fuel - $8.81/MM Kcal (LHV)

Table 9
Case 2, which uses C4 LPG as supplemental feedstock, has some 32 million dollars per year net raw material disadvantage, compared to the integrated plant of Case 3. This is because of the high value of propane and C4 LPG relative to ethane, and the low value (fuel value) of the C4 by-product. As shown from Table 6, Case 2 uses considerably more propane and C4 LPG feed and considerably less ethane feed than Case 3, and at the same time produces considerably more C4 by-product.

The 32-million-dollar disadvantage of Case 2 renders this case uneconomical for Thailand, and thus it is dropped from further consideration.

**Case 2 Conclusion**

Cracking of C4 LPG Not Justified

- C4 LPG Valued High
- By Products (C4's & C5+) Valued Low
- Incremental Net Raw Material Cost
- Prohibitively 32 $Millions/Year

**COMPARISON OF CASES 1 AND 3**

Cases 1 and 3 are compared in Tables 10 through 16. The tables give incremental consumptions or costs of Case 3 relative to Case 1. Table 10 summarizes the fuel consumption, Table 11 summarizes the consumption of utilities, Table 12 gives the annual consumption of catalysts and chemicals, while Table 13 compares initial inventories of catalysts and chemicals.

Table 14 gives the incremental installed cost of the ISBL facilities in mid-1933 instantaneous dollars, based on US Gulf Coast conditions and on Thailand conditions, respectively. Table 15 compares incremental annual operating costs for the two locations, and Table 16 gives the pretax payout of Case 3 over Case 1.
### Incremental Fuel—MMi KCal/Hr (LHV)

<table>
<thead>
<tr>
<th></th>
<th>Case 1</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Production*</td>
<td>Base</td>
<td>-45.2</td>
</tr>
<tr>
<td>Total Consumption</td>
<td>Base</td>
<td>+15.7</td>
</tr>
<tr>
<td>Net Production</td>
<td>Base</td>
<td>-60.9</td>
</tr>
</tbody>
</table>

*Includes Tail Gas, Fuel Oil, Mixed C4's, and Raw Gasoline

### Table 10

### Incremental Utilities

<table>
<thead>
<tr>
<th></th>
<th>Case 1</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel, MM KCal/Hr</td>
<td>Base</td>
<td>16</td>
</tr>
<tr>
<td>Steam Import @32 Kg/cm²g, Kgs/Hr</td>
<td>Base</td>
<td>-15900</td>
</tr>
<tr>
<td>Condensate Export, Kgs/Hr</td>
<td>Base</td>
<td>-20550</td>
</tr>
<tr>
<td>Cooling Water, m³/Hr (ΔT = 14°C)</td>
<td>Base</td>
<td>430</td>
</tr>
<tr>
<td>CT Make-up Water, m³/Hr</td>
<td>Base</td>
<td>20</td>
</tr>
<tr>
<td>Power Consumption, Kw</td>
<td>Base</td>
<td>130</td>
</tr>
</tbody>
</table>

### Table 11
### Catalysts and Chemicals
#### Incremental Annual Consumption

**Mid-1983 $ Thousands**

<table>
<thead>
<tr>
<th></th>
<th>Case 1</th>
<th>Case 3</th>
<th>US</th>
<th>Thailand*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Desiccant Base</td>
<td>-1</td>
<td>-1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Catalyst Base</td>
<td>891</td>
<td>891</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Caustic Base</td>
<td>-39</td>
<td>-39</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td>MEA Soln. Base</td>
<td>61</td>
<td>61</td>
<td>61</td>
<td>61</td>
</tr>
<tr>
<td><strong>Total</strong> Base</td>
<td>912</td>
<td>912</td>
<td>912</td>
<td>912</td>
</tr>
</tbody>
</table>

*Assume same as US Gulf Coast

**Table 12**

### Catalysts and Chemicals
#### Incremental Initial Inventories

**Mid-1983 $ Thousands**

<table>
<thead>
<tr>
<th></th>
<th>Case 1</th>
<th>Case 3</th>
<th>US</th>
<th>Thailand*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Desiccant Base</td>
<td>-7</td>
<td>-7</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Catalyst Base</td>
<td>1781</td>
<td>1781</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Caustic Base</td>
<td>-3</td>
<td>-3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>MEA Soln. Base</td>
<td>43</td>
<td>43</td>
<td>43</td>
<td>43</td>
</tr>
<tr>
<td><strong>Total</strong> Base</td>
<td>1814</td>
<td>1814</td>
<td>1814</td>
<td>1814</td>
</tr>
</tbody>
</table>

*Assume same as US Gulf Coast

**Table 13**
### Incremental ISBL Investment

**Mid-1983 $ Millions**

<table>
<thead>
<tr>
<th>Case</th>
<th>Case 3 —</th>
<th>US</th>
<th>Thailand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facilities Base</td>
<td>7.0</td>
<td>8.4*</td>
<td></td>
</tr>
<tr>
<td>Catalysts &amp; Chemicals Base</td>
<td>1.8</td>
<td>1.8**</td>
<td></td>
</tr>
<tr>
<td><strong>Total Base</strong></td>
<td><strong>8.8</strong></td>
<td><strong>10.2</strong></td>
<td></td>
</tr>
</tbody>
</table>

*Assume 20% More Than US Gulf Coast

**Assume Same As US**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Table 14</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Incremental Annual Costs

**Mid-1983 $ Thousands**

<table>
<thead>
<tr>
<th>Case</th>
<th>Case 3 —</th>
<th>US</th>
<th>Thailand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethane Feed Base</td>
<td>23,272</td>
<td>11,541</td>
<td></td>
</tr>
<tr>
<td>Propane Feed Base</td>
<td>(35,444)</td>
<td>(47,530)</td>
<td></td>
</tr>
<tr>
<td>By-products as Fuel Base</td>
<td>7545</td>
<td>3,358</td>
<td></td>
</tr>
<tr>
<td>Operating Labor Base</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Mant. Labor @ 1.8% of Invest. Base</td>
<td>126</td>
<td>151</td>
<td></td>
</tr>
<tr>
<td>Mant. Material @ 1.2% of Invest. Base</td>
<td>84</td>
<td>101</td>
<td></td>
</tr>
<tr>
<td>Overhead @ 150% of Mant. Labor Base</td>
<td>109</td>
<td>227</td>
<td></td>
</tr>
<tr>
<td>Utilities Consumed Base</td>
<td>946</td>
<td>632</td>
<td></td>
</tr>
<tr>
<td>Catalyst and Chemicals Base</td>
<td>912</td>
<td>912</td>
<td></td>
</tr>
<tr>
<td>Local Tax + Ins. @ 1.5% of Invest. Base</td>
<td>105</td>
<td>126</td>
<td></td>
</tr>
<tr>
<td><strong>Total Base</strong></td>
<td><strong>(2,265)</strong></td>
<td><strong>(30,482)</strong></td>
<td></td>
</tr>
</tbody>
</table>

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Table 15</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Payout of Case 3

**Mid-1983 Conditions**

<table>
<thead>
<tr>
<th>Case</th>
<th>Case 3 —</th>
<th>US</th>
<th>Thailand</th>
</tr>
</thead>
<tbody>
<tr>
<td>△ ISBL Investment, $MM Base</td>
<td>8.8</td>
<td>10.2</td>
<td></td>
</tr>
<tr>
<td>△ Operating Cost, $MM/YR Base</td>
<td>-2.3</td>
<td>-30.5</td>
<td></td>
</tr>
<tr>
<td>Pretax Payout, Years Base</td>
<td>3.8</td>
<td>0.33</td>
<td></td>
</tr>
</tbody>
</table>

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Table 16</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
PAYOUT OF CASE 3  As can be seen from Table 16, based on US Gulf Coast economic criteria, Case 3 requires an incremental ISBL investment of about 9 million dollars, compared to Case 1, but saves about 2.3 million dollars per year in operating cost. The pretax payout of the incremental investment of Case 3 is a little less than four years. This payout is marginal, and we consider Cases 1 and 3 at an economic standoff.

On the other hand, based on the assumed economic criteria for Thailand, the incremental investment of Case 3 is increased by about 20 percent to about 10 million dollars, but the saving in operating cost is significantly increased to some 31 million dollars per year. The result is a very attractive payout of less than four months for Case 3.

The main reason for this attractive payout is the low value assigned to the ethane feedstock, namely 122 dollars/MT in Thailand versus 246 dollars/MT in the US, - see Table 7 and 8, and the high values assigned to the propane feed, which are 350 dollars/MT in Thailand versus 261 dollars/MT in the US. This analysis shows how sensitive the selection is to the values assigned to ethane, and especially to propane.

CONCLUSION - CASE 1 VERSUS CASE 3  The required ethylene and propylene capacities desired by Thailand, namely 261,000 and 73,000 metric tons per year, respectively, can be met by steam pyrolysis alone. This holds true if all of the propane available in the country (217,000 mty) is cracked at very low severity (about 56 percent conversion) in order to produce the propylene, and about 70 percent of the available ethane is cracked separately at high severity to supplement the ethylene produced from the propane. Although it is feasible to produce the required olefins by pyrolysis alone, it is not economic to do so in Thailand.

However, if the propane feed is limited to much below the total available quantity, then propane dehydrogenation is necessary to produce the propylene in combination with ethane cracking to produce the ethylene as in Case 3. For this case, essentially all of the available ethane is required, but only 81,000 mty of propane, less than 40 percent of the total available quantity.
Between Cases 1 and 3, the economics in Thailand decidedly favor Case 3, which maximizes utilization of low-cost ethane and minimizes utilization of high-cost propane.

Case 1 vs Case 3 Conclusion

Case 1 – Ethane and Propane Cracking Only
  Feasible But All Propane Must Be Cracked
  Not Economic For Thailand

Case 3 – Combined C3 Dehydrogenation
  and C2 Cracking
  Feasible
  Only Viable Alternative If Less Than Total
  Propane Is Allocated
  Decidedly More Economic Than Case 1
  For Thailand
CASE 3 - INTEGRATED VERSUS SEPARATE PLANTS

The only consumer of propylene from this olefins complex is the downstream polypropylene unit. All of the other satellite units, namely polyethylene, vinyl chloride, and ethylene glycol, require only ethylene. The purpose of the propane dehydrogenation unit (PDU) is to produce the propylene for the polypropylene plant. The purpose of the ethane cracker is to produce ethylene for the ethylene users.

Integration of the PDU with the ethylene plant increases the capital and operating cost of the ethylene plant, and adds operating complexity. Understandably, the ethylene users are not very receptive to integration.

In this section we compare the integrated plant of Case 3 with separate and stand-alone PDU and ethane cracker. We refer to the separate plants as Case 3A. We believe integration results in lower overall investment and lower overall cost ethylene and propylene, which should give an incentive to all of the users to integrate the two plants. Our evaluation, conclusions, and recommendations follow.
CASE 3A - SEPARATE PLANTS  Figure 8 is a schematic flow diagram of a stand-alone propane dehydrogenation unit. Figure 9 is a schematic flow diagram of a stand-alone ethylene plant, based on ethane cracking.

The shaded equipment indicates services that are duplicated between the two plants. These include the third and fourth stages of the compressor, the driers, the deethanizer and the propylene refrigeration system.

In Figure 8, all of the C2's in the deethanizer overhead are lost to fuel. In Figure 9, all of the propylene and unconverted propane in the deethanizer bottom are also lost to fuel.
After two stages of compression, the dehydrogenation reactor effluent is sent to the suction in the cracked gas compressor of the ethylene plant. All of the dotted equipment in the C₃ dehydrogenation unit is now eliminated. But the depropanizer and C₃ splitter are transferred to the ethylene plant to handle the combined C₃ and heavier fractionation.

With this arrangement, all of the ethylene plant equipment downstream of the compressor inlet becomes bigger to accommodate the additional flow from the dehydrogenation reactor. The ethane is recycled to the C₂ furnaces as before, but all of the propane is recycled to the C₃ dehydrogenation reactor.

Notice that now all of the ethane and propane are recovered and recycled to extinction, and all of the propylene is recovered. The losses of the separate plants are thus eliminated, resulting in significant reductions in fresh ethane and propane feedstocks. The energy consumption is also reduced compared to the separate plants, due to elimination of duplicate services and due to the reduction of the total throughput.

INCREMENTAL ISBL INVESTMENT OF CASE 3A Table 17 shows the incremental installed capital of the ISBL facilities of the separate plants (Case 3A) over the integrated plant (Case 3) for mid-1983 conditions in the US Gulf Coast and in Thailand, respectively.
Case 3A suffers a capital disadvantage of 5 million dollars on US basis and 6 million dollars on Thailand basis.

INCREMENTAL NET RAW MATERIAL COST OF CASE 3A  Table 18 shows the incremental net raw material cost for Case 3A for US Gulf Coast, and Table 19 gives the same information at Thailand conditions. The incremental cost of feedstocks is taken as feed cost less fuel value.

Case 3A shows about 0.5 million dollars per year disadvantage at US conditions and a five-fold disadvantage, about 2.5 million dollars per year, at Thailand conditions.
### Integrated vs Separate Plants

#### Incremental Net Raw Material Cost

**US Gulf Coast, Mid-1983**

<table>
<thead>
<tr>
<th>Case 3 Integrated</th>
<th>Case 3A Separate Plants</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Feed</strong></td>
<td><strong>MTY</strong></td>
</tr>
<tr>
<td>Ethane Base</td>
<td>5500</td>
</tr>
<tr>
<td>Propane Base</td>
<td>9500</td>
</tr>
<tr>
<td><strong>Total Base</strong></td>
<td>15000</td>
</tr>
</tbody>
</table>

*(Feed Value) - (Fuel Value)*

Table 18

**Integrated vs Separate Plants**

**Incremental Net Raw Material Cost**

**Thailand Conditions**

<table>
<thead>
<tr>
<th>Case 3 Integrated</th>
<th>Case 3A Separate Plants</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Feed</strong></td>
<td><strong>MTY</strong></td>
</tr>
<tr>
<td>Ethane Base</td>
<td>5500</td>
</tr>
<tr>
<td>Propane Base</td>
<td>9500</td>
</tr>
<tr>
<td><strong>Total Base</strong></td>
<td>15000</td>
</tr>
</tbody>
</table>

*(Feed Value) - (Fuel Value)*

Table 19

**INCREMENTAL UTILITY COST OF CASE 3A**

Table 20 shows the incremental utility cost of Case 3A at US Gulf Coast conditions, and Table 21 shows the same information at Thailand conditions. Case 3A shows a disadvantage of about 1.5 million dollars per year at US conditions and about half that disadvantage, or 0.7 million dollars per year, at Thailand conditions.
### Integrated vs Separate Plants
**Incremental Utility Cost**
**US Gulf Coast, Mid-1983**

<table>
<thead>
<tr>
<th>Consumption</th>
<th>Case 3 Integrated Plants</th>
<th>Case 3A Separate Plants</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Per Hour</strong></td>
<td>$/Unit $ Millions/yr</td>
<td></td>
</tr>
<tr>
<td>Fuel Base</td>
<td>6.1 MMKcal 19.80 1.015</td>
<td></td>
</tr>
<tr>
<td>Steam Base</td>
<td>2.7 MT 15.40 0.349</td>
<td></td>
</tr>
<tr>
<td>Condensate Base</td>
<td>-0.4 m³ 1.32 -0.005</td>
<td></td>
</tr>
<tr>
<td>CW Base</td>
<td>287 m³ 0.026 0.063</td>
<td></td>
</tr>
<tr>
<td>Power Base</td>
<td>139 Kw 0.050 0.058</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>Base 1.480</td>
<td></td>
</tr>
</tbody>
</table>

Table 20

### Integrated vs Separate Plants
**Incremental Utility Cost**
**Thailand Conditions, Mid-1983**

<table>
<thead>
<tr>
<th>Consumption</th>
<th>Case 3 Integrated Plants</th>
<th>Case 3A Separate Plants</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Per Hour</strong></td>
<td>$/Unit $ Millions/yr</td>
<td></td>
</tr>
<tr>
<td>Fuel Base</td>
<td>6.1 MMKcal 8.81 0.451</td>
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<tr>
<td>Steam Base</td>
<td>2.7 MT 6.90 0.156</td>
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<tr>
<td>Condensate Base</td>
<td>-0.4 m³ 1.32 -0.005</td>
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</tr>
<tr>
<td>CW Base</td>
<td>287 m³ 0.026 0.063</td>
<td></td>
</tr>
<tr>
<td>Power Base</td>
<td>139 Kw 0.050 0.058</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>0.723</td>
<td></td>
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</table>

Table 21

**SUMMARY OF INCREMENTAL COSTS** Table 22 summarizes the incremental costs of Case 3A both at US Gulf Coast and at Thailand conditions.
### Integrated vs Separate Plants

#### Summary Incremental Cost
Mid-1983

<table>
<thead>
<tr>
<th></th>
<th>Case 3 Integrated Plants</th>
<th>Case 3A Separate Plants</th>
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<tbody>
<tr>
<td></td>
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<td>Thailand</td>
</tr>
<tr>
<td>ISBL Invest., $MM</td>
<td>Base</td>
<td>5.0</td>
</tr>
<tr>
<td>Net Raw Mat'l, SMM/YR</td>
<td>Base</td>
<td>0.5</td>
</tr>
<tr>
<td>Utilities, SMM/YR</td>
<td>Base</td>
<td>1.5</td>
</tr>
<tr>
<td>Evaluated Cost,*$MM</td>
<td>Base</td>
<td>11.0</td>
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<tr>
<td></td>
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</table>

* Δ Investment plus 3-Yr Δ Operating Cost

Table 22

The incremental evaluated cost (incremental capital plus three-year incremental operating cost) is 11 million dollars more at US conditions and more than 15 million dollars at Thailand conditions.

**CONCLUSION**  The integrated plant is significantly more attractive than separate plants, especially at the economic conditions prevailing in Thailand.
RECOMMENDATION  The integrated plant can produce the required olefins at lower investment, with less energy and less feedstock. Therefore, it will provide ethylene and propylene to the downstream users at lower cost than the two separate plants.

Clearly, from the standpoint of Thailand as a whole, integration is the preferred route because it conserves the country's resources in the most optimum way. This goal can probably best be achieved by a joint venture of the various parties, whereby the users of both ethylene and propylene can equitably share the overall savings in capital and operating cost resulting from an integrated plant.
REFERENCES


TABLES

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<td>Conventional High Severity Pyrolysis Conditions</td>
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<td>Options for Propylene Production</td>
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<td>Pricing Structure</td>
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<td>10</td>
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<td>Catalysts and Chemicals, Incremented Initial Inventories</td>
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<td>14</td>
<td>Incremental ISBL Investment</td>
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<tr>
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<td>Incremental Annual Costs</td>
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<tr>
<td>16</td>
<td>Payout of Case 3</td>
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<td>17</td>
<td>Integrated vs Separate Plants</td>
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<tr>
<td>18</td>
<td>Incremental ISBL Investment</td>
<td>26</td>
</tr>
<tr>
<td>19</td>
<td>Incremental Net Raw Material Cost, US Gulf Coast</td>
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<tr>
<td>20</td>
<td>Incremental Net Raw Material Cost, Thailand Conditions</td>
<td>26</td>
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<tr>
<td>21</td>
<td>Incremental Utility Cost, US Gulf Coast</td>
<td>27</td>
</tr>
<tr>
<td>22</td>
<td>Incremental Utility Cost, Thailand Conditions</td>
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</tr>
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<td>23</td>
<td>Summary of Incremental Cost</td>
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FIGURES

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<td>Case 2 Co-Crack C₃ and C₄, Crack C₂ as Needed</td>
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<td>Case 3 Ethane Cracking and Propane Dehydrogenation (Integrated Plant)</td>
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<td>3</td>
<td>Case 1 Process Flow Scheme Ethane Propane Cracking</td>
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<td>4</td>
<td>Case 3 Process Flow Scheme Ethane Cracking and Propane Dehydrogenation</td>
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<tr>
<td>5</td>
<td>Ultimate Ethylene Yield</td>
<td>11</td>
</tr>
<tr>
<td>6</td>
<td>Ultimate Propylene Yield</td>
<td>11</td>
</tr>
<tr>
<td>7</td>
<td>Stand-Alone Propane Dehydrogenation Unit</td>
<td>23</td>
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<tr>
<td>8</td>
<td>Stand-Alone Ethylene Plant</td>
<td>23</td>
</tr>
<tr>
<td>9</td>
<td>Integrated Plant</td>
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</tbody>
</table>
POLYPROPYLENE OPPORTUNITIES IN THE 1980'S

Presented February 9, 1984 by:

Charles J. Eckery and John W. Mayfield
HIMONT Incorporated

Thailand - U.S. Natural Gas Utilization Symposium
Siam Intercontinental Hotel
Bangkok, Thailand
Because HIMONT Incorporated is the world's largest polypropylene producer with approximately $1 billion in sales expected in 1984 and was only formed 3-1/2 months ago, I would like to briefly describe our company. This is our new commercial logo which we expect you will see a lot of in the future.

The parents of HIMONT are Montedison S.p.A. and Hercules Incorporated, both large companies primarily involved in the chemical industry. Montedison in 1982 had sales of approximately $6.7 MMM and Hercules during the same year had sales of approximately $2.5 MMM.

HIMONT Incorporated was officially formed on November 1, 1983 and resulted from the combination of the polypropylene resin business of Hercules Incorporated and the polypropylene resin, fiber and compound businesses of Montedison plus their catalyst and aluminum alkyls businesses. This included the very important segment of their polypropylene catalyst and process technology.

The company is organized into a central holding company, HIMONT Incorporated which is based in the U. S. plus four subsidiary companies - HIMONT Italia, HIMONT Belgium, HIMONT U.S.A. and HIMONT Canada. The four subsidiaries will handle our business in the U. S., Canada and W. Europe. In addition, our business outside these 3 areas of the world is handled by the HIMONT international department which has 93 sales offices in 76 countries and is backed in all areas by technical service representatives.

HIMONT is now the world's largest producer of polypropylene resin with capacity in place to produce 1.15 million tons per year (2.5 billion lbs.) of resin, 60 KT of polypropylene fiber and 41 KT/year of polypropylene compounds plus facilities for producing catalysts and aluminum alkyls.

HIMONT has 11 production facilities located in 4 different countries. This map indicates the locations and capacities.

The HIMONT polypropylene technology is the best in the world today, in terms of cost, quality, and the flexibility to produce new polypropylene products that our customers will need in the future.

We are proud of the position we hold in the industry and are optimistic about the future of polypropylene.
Today it is my pleasure to discuss polypropylene opportunities in the 1980's. I will begin with a brief history of polypropylene.

On the screen is a slide showing the explosive growth of plastic materials in the United States from the early 1940's to 1980.

This slide indicates the even more impressive growth of polypropylene in the United States, commencing in 1956 and continuing through 1980.

Here, as forecasted by a respected consulting firm, is the world demand for the five major thermoplastics. As you can see, the compounded annual growth rate for polypropylene is expected to be in excess of 7% in the period of 1980 to 1990.

During this period, the world demand in metric tons is to be as indicated for the six geographical regions. Asia, Western Europe, and the United States will continue to be the major consumers of polypropylene and are going to experience about the same growth rate.

This outstanding growth in polypropylene consumption is a result of two important features. First, is the economic value of its unique balance of physical properties; and secondly, the unusually large variety of applications in which polypropylene's utility has been demonstrated. I will briefly review these applications indicating some of the newer uses expected in the 1980's for this most versatile of thermoplastics.

By no means does this quick review cover all the applications for polypropylene, but I believe it has shown some of the more interesting and newer uses that will be occurring in the 1980's. I think it is very clear that polypropylene is the most versatile of all plastics, as demonstrated by its ability to be fabricated by many different processes and to be tailored to provide a wide-range of physical properties. During the years these applications were developing, the chemical processes to produce polypropylene were also advancing.

In the last few years, new polypropylene production processes have been developed that on the one hand have increased the family of products and on the other hand have considerably cut investment and production costs. The main process development driving force was catalyst evolution from the traditional Zeigler-Natta systems. The properties of such catalyst systems that have the stronger effects on polymerization are: 1) activity (expressed here in terms of kg
polymer/kg catalyst that can be obtained under industrial conditions; 2) stereospecificity (expressed here for polypropylene as isotacticity index which is the percentage of polymer not soluble in hot heptane); and 3) morphology of the produced polymer (that is the bulk density, particle size distribution, regular geometry of polymer particles). The traditional Ziegler-Natta catalysts ("first generation" catalysts) had low activity, low stereospecificity and produced polymer in powder form with irregular morphology, wide particle size distribution, and low bulk density. Their activity was in the region of 500 kg polymer/kg catalyst; stereospecificity was about 85%. At such performance levels, the polymerization processes needed a catalyst residue removal step; and as regards to polypropylene, atactic polymer removal. The typical processes with "first generation" catalysts are solvent-based, either solution or slurry, because solvent is the necessary medium for catalyst residue and atactic polymer removal. Between the late '60s and the early '70s, high activity catalysts were developed for ethylene polymerization. These new catalyst systems, however, had a very low stereospecificity. Only in the middle '70s was success achieved in developing a propylene polymerization catalyst system with an activity around 4,000 kg polymer/kg catalyst and 90% stereospecificity (a so-called "second generation" catalyst). This improved catalyst performance allowed the development of "high-yield" polypropylene processes requiring no catalyst residue removal. Polymerization took place in a hydrocarbon slurry; the solvent was still necessary for atactic polymer removal. The investment and operating costs were reduced. Further catalyst research work allowed a high stereospecificity (isotactic index greater than 95) high-activity system (a so-called "third generation" catalyst). The production process and the investment and operating costs were sharply reduced. At this stage, it became possible to select a polymerization process without solvent, such as a liquid monomer process. More recently methods have been developed for accurate control of the polymer particle size without affecting the high catalyst activity or stereospecificity. The polypropylene produced with the "fourth generation" catalyst, which attains an activity of 15,000 kg polymer/kg catalyst, appears as a very small regular-size sphere with a high bulk density and narrow particle size distribution. It can be fed as produced to the thermoplastic processing equipment, instead of the usual pellets. The production process is extremely simple and cost cuts reach unprecedented levels.

Here is shown a typical slurry process employing a low-yield catalyst. In blue is shown the polymerization section employing five reactors. In red are the unit operations to remove residual catalysts and recover atactic polymer. In yellow are the solvent recovery systems. Now compare this with a modern process.
Shown is the HIMONT Spheripol process employing a "fourth generation" high-yield catalyst. The simplification of the process is dramatic. In blue is a single loop polymerization reactor. In red is the propylene recovery and polymer drying section.

In this slide, comparative investment costs of a Spheripol process, with and without pelletizing, are compared to a conventional slurry process with a low-yield catalyst. As you can see, the investment of a Spheripol process with pelletizing is only 65% of a conventional plant. Without pelletizing, this drops to 44%. If pelletizing is not employed, the Spheripol particles can be produced over a variety of selected particle sizes.

These are Spheripol particles. On the left are Spheripol particles about 5mm in diameter, the size of large pellets. Adjacent are particles about 3mm in diameter, about the size of small pellets. On the right are smaller Spheripol particles, approximately 1mm and 1/2mm in diameter with magnified views shown above. These small particles are most suitable for compounding with pigments and mineral fillers.

Reviewing the outstanding features of this Spheripol process, one must mention first the very high-yield, which allows for a very low investment cost. It should also be mentioned this is a very clean process, as it is not necessary to dispose of spent catalysts. The monomer required for the process requires only the conventional purity. Furthermore, chemical grade monomers can be used, containing up to 40% propane. This simplified process reduces steam consumption to only 1/10th of what is normally used and the maintenance costs are only 1/3 of those of a conventional plant. Because of the design characteristics of this process, it can be scaled up in size almost without limit. The process is capable of producing a full polypropylene product line - homopolymers, random copolymers, or impact copolymers; and lastly, the plant can be operated with great flexibility to produce the large product mix required to meet the many and varied applications for polypropylene. This technology has been demonstrated in two industrial plants employing the Spheripol process and "fourth generation" catalysts.

These plants have been operational in Italy since December 1982 at Ferrara and since April 1983 at Brindisi. The model shown on the screen is typical of these plants which are currently supplying about ten thousand metric tons per month to the European market.

In summary, the most advanced technology in the world is in place to support the world's fastest growing thermoplastic - polypropylene.
MONTEDISON, S.p.A.
1982 SALES — $6,700 MM

BASIC PETROCHEMICALS
PLASTICS
FERTILIZERS
PESTICIDES
PHARMACEUTICALS
FIBERS
ORGANIC INTERMEDIATES
ENERGY
RETAILING
SERVICES AND ENGINEERING
OTHERS
HERCULES INCORPORATED
1982 SALES — $2,500 MM

ORGANIC CHEMICALS
PLASTICS
WATER SOLUBLE PRODUCTS
EXPLOSIVES AND AEROSPACE
OTHERS
MONTEDISON
PP RESINS
PP FIBERS
PLUS SHARE IN NEOFIL JV
PP COMPOUNDS
PP TECHNOLOGY
CATALYSTS
ALUMINUM ALKYLs

HERCULES
PP RESINS
PP FIBERS — NEOFIL SHARE ONLY
PP TECHNOLOGY

HIMONT INCORPORATED
LEGAL STRUCTURE

HIMONT Incorporated

HIMONT U.S.A. Inc.

HIMONT Italia S.p.A.

HIMONT Canada Inc.

HIMONT Belgium N.V.
## WORLD THERMOPLASTIC DEMAND

<table>
<thead>
<tr>
<th>RESIN</th>
<th>COMPOUND ANNUAL GROWTH RATE, %</th>
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<tbody>
<tr>
<td></td>
<td>1980 - 1990</td>
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<tr>
<td>POLYPROPYLENE</td>
<td>7.3</td>
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<tr>
<td>POLYETHYLENE</td>
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</tr>
<tr>
<td>HIGH DENSITY POLYETHYLENE</td>
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<td>POLYSTYRENE</td>
<td>5.2</td>
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<tr>
<td>POLYVINYLCHLORIDE</td>
<td>5.8</td>
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### WORLD POLYPROPYLENE DEMAND
(THOUSAND METRIC TONS)

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<tr>
<th>Region</th>
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<th>1990</th>
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<tr>
<td>CANADA</td>
<td>95</td>
<td>165</td>
<td>245</td>
</tr>
<tr>
<td>UNITED STATES</td>
<td>1370</td>
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</tr>
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<td>ASIA</td>
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<tr>
<td>TOTAL</td>
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### CATALYST PERFORMANCE

**PROPYLENE POLYMERIZATION**

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<th>Generation</th>
<th>Activity (Yield)</th>
<th>Isotacticity Index - %</th>
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<tr>
<td>1954</td>
<td>1st generation</td>
<td>500</td>
<td>85</td>
</tr>
<tr>
<td>1975</td>
<td>2nd generation</td>
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<td>1980</td>
<td>3rd generation</td>
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<tr>
<td>1982</td>
<td>4th generation</td>
<td>15,000</td>
<td>97</td>
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SLURRY PROCESS  LOW YIELD CATALYST
SPHERIPOL PROCESS

Diagram showing the flow of materials through a process involving catalyst, chemicals, propylene, hydrogen, and additives, with a final output going to bagging.
<table>
<thead>
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<td>Polymer/Solvent Separation</td>
<td>8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Drying</td>
<td>9</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Pelletizing</td>
<td>20</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Storage</td>
<td>16</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100</strong></td>
<td><strong>64</strong></td>
<td><strong>44</strong></td>
</tr>
</tbody>
</table>
KEY FEATURES - SPHERIPOL PROCESS

HIGH YIELD

LOW INVESTMENT COST

CLEAN PROCESS

MONOMER PURITY - CONVENTIONAL

CHEMICAL GRADE MONOMER

LOW ENERGY REQUIREMENT

STEAM CONSUMPTION - 1/10 OF CONVENTIONAL

LOW MAINTENANCE COSTS - 1/3 OF CONVENTIONAL

NO PROBLEM TO SCALE-UP PROCESS

PRODUCES FULL PRODUCT LINE

HOMOPOLYMER

RANDOM COPOLYMER

IMPACT COPOLYMER

PRODUCT MIX FLEXIBILITY
Combustion Engineering Simcon, Inc., formerly the C-E'Lummus Digital Technology Center, has been established as a new unit of Combustion Engineering Inc. Simcon's Charter is to maximize total plant performance by making the most efficient possible use of equipment, personnel and information. As a part of this task, Simcon designs and implements advanced process control systems, and simulators for training, engineering and advanced applications.
INTRODUCTION

The use of simulators for training was pioneered in the nuclear and aerospace industries. This training was so successful that the nuclear industry now estimates 4 months of simulator training as the equivalent of 1 year of traditional training. More recently, the U.S. government has accepted simulator training as a total program, sufficient in and of itself to prepare all airline crews for their jobs.

In the last decade, the process industry has begun to adopt simulator training for both inexperienced and experienced process plant operators who will run both existing and new plant control systems.

In its design, a training simulator must take into account process dynamics, control system configurations, plant operations, and training requirements, as well as the latest simulation techniques.
Combustion Engineering Simcon, Inc., formerly the Digital Technology Center of the C-E Lummus Company, is a leading supplier of dynamic digital simulators suitable for operator training, control system assessments, and instrumentation checkout. In this presentation, we will discuss the features of training simulators, the characteristics of state-of-the-art simulation software, a simulator-based training program, and the steps in executing a simulator project for a process plant.

Simulator Training versus Traditional Methods

Classroom training, while providing essential theoretical knowledge through oral instruction and written material, has never given operators the practical skills they need to run a real plant. This task has been traditionally assigned to in-plant observation and a time consuming training period under the supervision of experienced operators. Assuming that the actual plant is available for training purposes, which is not always the case, on the job training cannot guarantee trainees the chance to observe a given malfunction or rare procedure. As a result, many new operators are forced to handle unfamiliar problems or actual emergencies in the actual plant without benefit of experience during training. Poor operating methods and operator errors now carry such high costs in lost product and damaged equipment that operating companies have had to search out new training methods to prevent them.
The simulator has attracted attention as the method which allows trainees to practice operating procedures under a very wide range of plant conditions in a realistic environment.

Additionally, if designed properly, the same simulators used in training can be used to check out control systems and strategies before they are implemented in the plant.

The training simulator provides impressive advantages:

- Actual plant operating efficiency is improved as trainees learn better ways to manage operations, and how to react properly to malfunctions, upsets, startup, shutdown and emergencies.

- The potential for human error and its costs are reduced and safety is improved due to plant operators' prior experience on the simulator.

- New plants can be placed onstream earlier since startup can be rehearsed through simulation.

- With shortened, more efficient simulator training periods, plant managements are better able to prepare new operating staff, compensate for high operator turnover, and refresh the skills of experienced operators.
New technology, such as digital instrumentation and control systems, can be taught more easily, quickly, and thoroughly than ever before.

The result is improved plant performance dividends far in excess of simulator costs.

THE STRUCTURE OF A SIMULATOR

Simcon's PROGRESS™ digital training simulator has five major components: the trainee station, a computer, the instructor station, the simulation software, and the software process models of the unit or plant area (Figure 1).

Trainee Station

The trainee station (Figures 2 and 3) is a realistic replica of the controls and displays (either digital or analog) that the trainee operator will use in the real plant control room. In some cases, console emulation will be used rather than actual instrumentation. This amounts to replicas of the screen displays (and keyboards) of actual digital control room instrumentation, but installed on far less expensive equipment. Through his station, the trainee observes and "controls" simulated operations. He learns how to start up and shut down the plant, and how to deal with disturbances, emergencies, and requests for changes in operating
conditions. He becomes accustomed to handling radio communications, recording and logging devices, telephones, and other distractions identical to those occurring in real conditions. Instructors can use this equipment to generate the sort of inconvenient interruptions with which the trainee will soon have to live.

Computer

The computer runs the software model of the plane, and such ancillary equipment as I/O devices for connection to the trainee station, disks for storing data, and printers for logging events and faults. The computer can range in size from a small micro or minicomputer system, up to a powerful 32-bit "super mini" (Figure 4). Hardware is specified on a case-by-case basis and is easily expandable.

Instructor Station

The instructor station, usually a CRT with a full keyboard, is linked directly to the computer. The instructor, working at his station and usually out of the trainee's sight, may specify initial conditions; for example, a custom condition specific to a process or plant, normal operating conditions, or an intermediate stage in a startup routine. The instructor can insert disturbances into the process to simulate a variety of equipment malfunctions and fault conditions.
The instructor may also freeze, restart, or rerun the simulation, as well as manipulate various remote functions to simulate the action of a field operator (Figure 5).

**Simulation Software (GEPURS™)**

GEPURS simulation software operates under the standard operating systems and consists of the following major elements:

- Simulation processor

  The simulation processor dynamically simulates the process and provides development aids for the model development engineer.

- Instructor station processor

  The instructor station processor processes instructor input through the keyboard and generates the appropriate display on the instructor station CRT. This processor allows the instructor to control the training exercise and monitor the trainee's performance.
This processor is based on the GEPURS graphic package. The graphic package fetches the value of the simulated variables and refreshes the instructor station displays. When the instructor enters a command, the graphic package updates the simulation model data base.

Emulated trainee station processor

The emulated trainee station processor processes the trainee's input through the keyboard and generates the appropriate display on the trainee station CRT. This process allows the trainee to manipulate the controllers and on/off switches.

This processor is based on the GEPURS graphic package and operates like the instructor station processor.

Communication between the processors is via the common data base. The simulation processor executive controls the entire simulation software by controlling the timing based on the real-time clock and activating/deactivating the other processors.

In addition the simulation processor contains the following:

- Engineer station processor
The engineer station processor lets the engineer freeze/resume simulation, monitor the process variables, activate/inactivate the block, initialize the value of the block output(s), set/reset the Boolean table, and save/load the model data base and simulated variables.

- Math model execution processor

The math model execution processor executes a series of algorithms assigned to the blocks in a specific sequence and timing. It scans all the blocks during every basic timeframe and, if the execution timer of a block expires, executes the block. For each block to be executed, this processor fetches the simulated values of the block inputs and sends those values with the block parameters to algorithm subroutines that update the block output(s).

- Autodocumentation processor

The autodocumentation processor generates and formats the model data base, simulated variables, and software programs to minimize the documentation effort.

GEPURS software is used as a simulation language to develop the software process models which it runs (Figures 6 and 7). GEPURS software is based on a block structure, with any piece of equipment represented by one or
more blocks. These software blocks contain mathematical equations that calculate temperature, pressure, flow, and other process dynamics. There are blocks for pumps, heat exchangers, and other pieces of equipment. Once a particular type of equipment (e.g., a compressor) has been created, a similar item can be modeled by inserting new block parameters using a fill-in-the-blanks procedure.

The blocks are linked together to build a process unit, a plant area, or a total plant complex, depending on what the user wants to simulate.

Configuring, connecting, and disconnecting the various blocks, and assigning or modifying process parameters, and changing execution times, should be quick and easy procedures, accomplished on-line while the model is running. These features also come into play when the model is tested, fine tuned and integrated with other models. Engineers observe the models in action while tuning the parameters and do not have to update source programs or recompile. In these respects, GEPURS differs from other software approaches (Table 1). The result is that client engineers can be trained in a matter of about four weeks to create and update their plant models as training objectives or the plant itself change.

At a more advanced level, engineers learn to create their own calculation sequences and Fortran programs to supplement the standard functions available in GEPURS. They can develop models suitable for checking out changes to their control system.

Figures 8 and 9 show the block configuration of a pump, tank, and heat exchanger, using GEPURS.
Process Models

A simulation model duplicates the plant's actual process responses and equipment functions under normal operating conditions, during plant startup and shutdown, and during equipment malfunction and process upsets. To be effective, this model will produce on the trainee's instrumentation: (1) a correct and realistic response reflecting the process under any plant condition selected by the instructor, and (2) a correct and realistic response to any actions taken by the trainees.

The level of detail (fidelity) built into the process models depends on the clients training requirements. For example, a column can be constructed of as many trays as necessary. The more trays, the more fidelity in the model. For training purposes, models generally fall into three categories of fidelity and complexity (Figure 10).

Standard unit operation models simulate a small section of the plant or a major piece of equipment. These models are typical, that is, not specific to any particular plant; they are used to teach the trainee the concept of operations. Examples would be a fired heater or typical distillation column.

Standard plant models simulate a typical plant, generally modeled one operating area at a time, as operations in each area are somewhat independent. However, simulation on a greater scale is possible. A plant
model exposes the trainee to the process, the equipment, and plant operating procedures. Here the trainee learns not only how specific pieces of equipment are operated, but how they interact with each other. He must consider the total effect on the plant of adjustments or changes he makes.

A custom model is specific to a given plant, and incorporates the plant's actual operating parameters and data. Trainees learn the operating procedures for their own plant. The choice of level is, therefore, defined by the type of training to be undertaken.

Anatomy of a Model

Let us take the example of a gas gathering and compression operation (GGCO). This process might involve modeling several types of compressor trains, for example, spheroid gas, trap gas and onshore gas. For illustration purposes, this discussion will concentrate on the onshore compressor system.

Three categories of information are needed to translate the above process into a simulation model: the Process Flow and the P&I Diagrams, the operating procedures, and the training requirements.
Figure A shows a process flow diagram for the GGCO's onshore compressor station in a gas compression train. This diagram defines the flow of mass and energy through the compressor station. It also defines the type and amount of the major process equipment used, and the interactions of this process equipment.

Figure B, a P&I diagram, defines the instrumentation control loops and safety interlocks of the equipment. This diagram, or a second P&I, will also indicate the equipment used by the control room or board operator and by the field operators.

An understanding of the plant's operating procedures, including those used in normal operation, in startup, shutdown, and process upsets, requires discussions with the client. It is a great advantage if the simulator vendor has a good process industry background. He must know and understand not only the process, itself, but the failures and malfunctions that the client may reasonably expect, and the procedures the operator should use to respond to them.

Using the above information, the model is defined to meet the client's training objectives. The level of detail (fidelity) at which the model must simulate the actual plant and its conditions is defined. A high fidelity model will respond almost exactly as the dynamics of the plant respond, and predicted values of the model's variables will match actual
FIGURE A.

PROCESS FLOW DIAGRAM

ONSHORE GAS COMPRESSION
FIGURE B.

PIPING AND INSTRUMENT DIAGRAM

ONSHORE GAS COMPRESSION

ONSHORE COMPRESSION STATION
plant variables. Lower fidelity models will simulate correctly, but in less detail. Initial conditions are defined and established from the design data if the plant is new, and from actual plant operating data if the plant already exists. Selected malfunctions are defined.

The next step is a simplified diagram, the "model diagram", of the plant area or unit from which the model will be built. The "model diagram" incorporates only those functions, equipment and control systems that will be simulated. Figure C is a model diagram of an onshore compressor diagram, and includes the suction drums, compressors, compressor aftercoolers and knockout drums that will be modeled. They are configured in a sequence matching that of the plant, and respond to the flow of mass and energy through them. In this model diagram, the "bubbles" with the line through them define the control board operator functions; the circles "RF" indicate the field operator functions (remote functions). From this model diagram, a block structured logic diagram is built. Figure D is a block diagram of a first stage compressor.

Most of the blocks required for the model already exist in the GEPURS library. In the GGC0 gas compression model, one GEPURS block is used to simulate one compressor stage for illustration purposes. In the library, however, ready made blocks are available that simulate multiple stages and pieces of equipment, (e.g. operation of the compressor and the suction
FIGURE D.

BLOCK DIAGRAM

1st STAGE COMPRESSOR
For new blocks, mathematical equations representing both the process and the equipment would be developed and programmed as the new blocks.

Detailed parameters for the blocks in the GGCO's onshore compressor are calculated from equipment data sheets such as the one shown in Figure E, and also - if it is available - from actual plant operating data. These parameters are entered into their appropriate blocks with a fill-in-the-blanks procedure (no programming). For instance, Figure F shows a block in the compressor which computes dynamic responses of discharge pressure and temperature. In this block, both digital and analog inputs and outputs have been entered, including flows, temperatures, pressures and compressor speed. Any number of controlled variables, for example, discharge pressure or flow, are simulated in this way.

As the blocks are completed, they are assigned their sequence and frequency of execution, and interconnected on-line to match the configuration determined in the model diagram. As part of this process, blocks that simulate malfunctions (Figure G) are included. For example, a block with a malfunction (failure closed) of the suction drum discharge valve is modeled by setting what we call the control or "malfunction" bit. A signal from the instructor would cause the level valve to close, loading to level alarm; the trainee would have to respond to this level alarm. With all blocks configured, interconnected, and sequenced for execution,
**EQUIPMENT DATA SHEET**

### Service

**IX-032/K-203 ONSHORE COMPRESSOR ANTI-SURGE**

**LINE SIZE AND SPECIFICATION**

<table>
<thead>
<tr>
<th>NAME</th>
<th>10&quot;, RA/RA</th>
<th>10&quot;, RA/RA</th>
</tr>
</thead>
</table>

**MANUFACTURER**

MCKINSEY & ROBBINS INC.

**MODEL NUMBER**

FAV-157

### General Revision Information

**VEVE BODY**

MCKINSEY & ROBBINS INC.

**VALVE ACTUATOR**

IN V RCH

**VALVE POSITIONER**

IN V RCH

### Process Data

**FLUID**

MAX GASEOUS UNIT OF FLOW RATE

### Connections Rating & Facing

**NOTE**

- **TYPE OF PLUG GUIDING**

**CAGE**

### Valve Body Specification

**BODY STYLE**

NOISE REDUCTION

**BODY MATERIAL**

ASTM A181 W/417

**SEAT MATERIAL**

BUTTERFLY VALVE CLASS

**REVISIONS**

VEE-HOT BAIL/STROKES

### Valve Approval

**VALVE BODY SPECIFICATION**

**BODY STYLE**

NOISE REDUCTION

**BODY MATERIAL**

ASTM A181 W/417

**SEAT MATERIAL**

BUTTERFLY VALVE OPENING

### Body Drain Plug

---

### Actuator and Accessories Specification

**ACTUATOR TYPE AND SIZE**

C8-1020-4-30-24.0

**SPRING RANGE AND TRAVEL**

1/3" MIN. HYDRAULIC SPRING RANGE

**INCREASING AIR SIGNAL VALVE**

1/4" MALE F/F

**TRIP VALVE AND VOLUME TANK**

OPEN POISONER INPUT

**LOCK VALVES**

NO Bypass

**ACTUATOR PRESSURE RATING**

400 PSI

**SIZING**

**APPROVED FLANGE CONSTRUCTION**

---

### Valve Size Calculation

**Control Valve Size Calculation**

Let $C_v = \frac{Q \cdot \sqrt{10}}{F_L P}$ = 0.145

With $y = 1.55$ and $L = 0.3656$

$C_v = 0.75 \times \sqrt{114.59} = 640$

**NOTE**

VENDOR TO CHECK SELECTION, SIZING, AND MATERIALS OF VALVE AND COMPLETED OR CORRECTED COPY TO PURCHASER WITH QUOTATION.

### Control Valve Calculation and Specification

**PLANT NO.**

GETTHE

**INDEX**

124

**DRAWING NO.**

K-0010-12
VOLUMETRIC FLOW
\[ V_C = \frac{K_7 F (T_S + K_2)}{P_S} \]

SURGE LIMIT
\[ V_S = K_7 N + K_77 \]

PERFORMANCE CURVE
\[ \frac{P_D}{P_S} = n (K_4 V^2 + K_5 V + K_6) \text{ FOR } V > \frac{V_S}{2} \]

DISCHARGE TEMPERATURE
\[ T_D = (T_S + K_2) \left( \frac{P_D}{P_S} \right)^{\frac{1}{V}} - K_2 \]

COMPRESSOR HEAD
\[ H = R (T_S + K) \frac{Y-1}{\left( \frac{T_D + K_2}{T_S + K_2} \right)} \]

LOAD TORQUE
\[ L = K_{10} F H / (N + 10) \]

COMPUTES DYNAMIC RESPONSE OF DISCHARGE PRESSURE AND TEMPERATURE
FIGURE G.
SIMULATION OF MALFUNCTION

SWITCH BLOCK

E₁

CONTROL BIT

CODE 1

CODE 2

E₀

LOGICAL BLOCK

MALFUNCTION BIT

LOGICAL "NOT"

LOGICAL "AND"

SUCTION DRUM MODEL

LEVEL CONTROLLER
there remains the final task of tuning the model so that its dynamic responses match those of the plant. Once again, it is necessary to refer to operating or design data to determine the exact response which is desired. Teaching features are integrated. The model should now be almost ready to go. It is tested against the specifications and requirements of the client, debugged and accepted.

SIMULATION-BASED TRAINING PROGRAMS

The simulator is a training tool that works best as part of an integrated training program. Such a program makes use of classroom training, observation and a range of teaching aids including programmed learning materials and interactive video technology, to supplement hands-on simulator practice. Planning, scheduling, pretesting, measurement and other tasks normal to the preparation and conduct of any training course are part of a simulation-based training course. It is worth noting that a job element approach is often used in planning, as it lends itself to simulator training (Figure 12). In this approach, an overall job is divided into elements or tasks, beginning with the basic ones, such as when and how much to open or close a valve (Figure 11). Completion criteria are defined for each task, so that trainees can be evaluated before they proceed to the next task. Trainees progress from simple to complex job elements until they master all the elements in a job.
The task approach creates standards of performance that are observable, measurable, and directly related to the eventual performance of the trainee in the plant. A trainee is qualified based on his mastery of real tasks rather than on subjective evaluations. If the trainee fails to perform adequately, his specific problem can be addressed by retraining in the applicable job element.

The usual phases in operator training using a simulator are:

- Pretraining (classroom): the instructor explains, and the trainees study the theory and principles of process plant operation with specific reference to the plant the trainee is to operate. The trainee passes a written test at end of this phase.

- Briefing (classroom): The instructor explains the exercises the trainee will have to carry out on the simulator.

- Control system training (simulator): trainees gain hands-on familiarity with control room instrumentation and how it works.

- Basic process training (simulator): trainees learn to operate the process while it is running normally, and handle malfunctions, and upsets.
- Advanced process training (simulator): trainees learn to start up the plant and to perform a planned shutdown, and to diagnose and correct all specified conditions while operating the plant at maximum possible efficiency.

- Performance review (classroom)

- Measurement of learning (simulator) where the operator is asked to operate the simulator to the standards of his job in the plant.

PROJECT EXECUTION

Once the decision is made to train operators on a simulator, the simulator must be specified to reflect the actual plant operations, and the procedures which operators will have to handle. The process dynamics, control system configurations, and plant operations are all important to the design of the simulator; the scope of the simulation will be a function of the training requirements.

There are generally four major stages in executing a process simulator project. They are: collection and collation of plant data; preparation of the functional specification; model development; and model loading, debugging, and acceptance testing.
Collection and Collation of Plant Data

Plant data should include a basis for process design, heat and material balances, thermodynamic properties of all fluids, equipment specification and configuration, and operating procedures (including such details as control valves and pump characteristics).

If the training program is to include startup and shutdown, the data must cover all operating conditions from cold start to maximum throughput.

Preparation of the Functional Specification

A functional specification is prepared by the simulator supplier and is consistent with the user's requirements. This specification will identify standard or special hardware and its configuration. All models are identified and defined in enough detail necessary to a satisfactory training program, but within the constraints of practicality.

The specification defines the process variables to be interfaced with the control system, initial conditions, and the malfunctions to be included in the model. Malfunctions should represent, where possible, each of the different types of process and equipment upsets that are likely to occur on the real plant.
The specification also identifies the field operator functions required; that is, the valves and pumps that are not accessible to the control room operator, but must be manipulated under his direction by a field operator. In the model, these are remote functions handled by the instructor at the trainee's request.

**Model Development, Loading, Debugging, and Acceptance Testing**

The models are developed, as described earlier. They are then loaded into the computer for testing, debugging, and client acceptance.

At the completion of this phase, the system is ready for shipment to the job site.

**CONCLUSION**

With its realism and flexibility, the dynamic training simulator can offer substantial benefits to the process industry. The simulator should duplicate the operations and equipment of the real plant so that operator skills transfer directly from the simulator into the plant control room. It should be easy to modify, both in hardware and software, to keep pace with changing technologies and training needs. It should be flexible
enough to assist with all types of training: introducing novice operators to process concepts, keeping experienced operators skilled in rare or unusual procedures, and retraining or upgrading operators for new technologies. It can also be designed with the fidelity required to test control strategies. Finally, the simulator should be easy for process personnel to use during training and model development.

With these qualities, the current generation of dynamic digital simulators are powerful tools for the process industry.
Table 1. Advantages of Using GEAPURS in Model Development

1. Configuration through a CRT console using a fill-in-the blank format

2. Dynamic reconfiguration using CRT displays

3. Dynamic tuning (no compiling and no source programs to update)

4. Tabular displays and graphic plots that monitor simulated process variables, for testing a model during integration

5. Dynamic control over model execution time

6. Selective activation and deactivation of any portion of the model

7. Ability to provide an emulated instrumentation interface or be hardwired to any analog or digital instrumentation
FIGURE 2.

SIMULATION CONCEPT

OPERATOR

ACTUAL PROCESS FACILITY

OPERATOR TRAINEE

REAL-TIME SIMULATION COMPUTER

OPERATOR TRAINING SIMULATOR

INSTRUCTOR

PROCESS UNITS
THE TRAINEE STATION

- DIGITAL OR ANALOG INSTRUMENTATION

- EMULATION OF GENERIC OR ACTUAL INSTRUMENTATION
THE SIMULATION COMPUTER

- MICROCOMPUTER LINE

- 16 OR 32 BIT MINICOMPUTER LINE
THE INSTRUCTOR STATION

- OVER-THE-SHOULDER INSTRUCTION
- STANDARD TERMINAL, REMOTE FROM TRAINEE
- INSTRUCTOR LOG, BACKTRACK, REPLAY, GRAPHIC PRINTING FUNCTIONS
- CREATION AND UPDATING OF MODELS
FIGURE 6. JEPURS SIMULATION SOFTWARE STRUCTURE

Operating Systems

Common Database

Instructor Station Processor

Simulation Executive

Emulated Trainee Station Processor

Engineering Processor

Math Model Processor

Auto-Documentation Processor

Algorithm 1

Algorithm 2

Algorithm N
THE GEPUFS SIMULATION SOFTWARE SYSTEM

- MODELS OR REMODELS ANY PROCESS ACCURATELY, QUICKLY AND FAITHFULLY
- GENERAL-PURPOSE, CROSS-INDUSTRY APPLICATION
- REAL-TIME, DYNAMIC
- ON-LINE AND INTERACTIVE FINE TUNING, UPDATES, AND CHANGES
- ON-LINE INTERACTIVE MODELING
- USER FRIENDLY
FIGURE 12.

TASK ANALYSIS

- START FEED PUMP
  - SHUT VALVE FCV-101
    - PUT FIC-101 IN MANUAL
      - RAMP OUTPUT TO ZERO
    - INSTRUCT FIELD OPERATOR TO ADJUST BLOCK VALVES
      - PUSH HS-101A
        - VERIFY SL-101A
      - START MOTOR
        - CHECK PI-105 INCREASES
  - OPEN FCV-101 10%
FIGURE 9.

BLOCK STRUCTURE FOR

PUMP, TANK AND HEAT EXCHANGER
FIGURE 10.

PROCESS MODELS

PROJECT START

LICENSE data

PLANT DESIGN DATA

PLANT

UNIT OPERATION MODELS
- COMPRESSOR
- BOILER
- BINARY DISTILLATION COLUMN
- FIRED HEATER
- PYROLYSIS HEATER
- REFRIGERATION SYSTEM
- CATALYTIC REACTOR
- FURNACE
- FRACTIONATOR
- ABSORBER
- EXTRACTOR
- REFORMER
- ETHANE/ETHYLENE SPLITTER

STANDARD PLANT MODELS
- GAS CRACKER
  - HOT SECTION
  - FRACTIONATION SECTION
  - COLD SECTION
- LUBE OIL
  - PROPANE DEASPHALTING
  - FURFURAL EXTRACTION
  - MEK EXTRACTION
  - HYDROTREATING
  - HYDROFINISHING
  - VACUUM DISTILLATION
- CRUDE ATMOSHERIC DIST.
- OIL PRODUCTION PLATFORM
- FLUID CATALYTIC CRACKING

CUSTOM MODELS
- SIMCON DESIGNED
- USER DESIGNED
- JOINTLY DESIGNED
JOB E1flMET TRAINING

FIGURE 11

00
th

--

CHECK
BLOCK
VALVES

--

FLAME
OPERATE
CIUDE
UNIT--

SRE UP
;TART
UNIT
CRUDE

-

-

SYSEMS
INTRODUCE
FEED

SHUT VALVE

--

VALE
CHECK

[

-

-

START

INSTrUCT FIELD
OPERATOR TO
ADJUST BLOCK VALVES

FEED PUMP
M

START MOTOR"--1

VACUUMCHECK
OPERATE
PLANT

IN MANUAL
RAMP OUTPUT TO ZERO

-

S

OPERATE
VACUUM

'

PU
"lUTFiCI0I

PUSH HS.101A
VERIFY SL-IOIA
iEKP-0

PI-105
INCREASES

UNIT
-OPEN

FCV-101 10%

OPERATE
REFORMER
JOB ELEMENT


FIGURE 8.

MODEL OF PUMP, TANK AND HEAT EXCHANGER
Your Excellency, Distinguished Guests, Ladies and Gentlemen:

As the Thailand-United States Natural Gas Utilization Symposium draws to a close, I am sure you can all look back with great satisfaction to the discussion you have had and the conclusions you have arrived at during the last three days.

It gives me great pleasure indeed to learn that the Symposium has produced highly encouraging results, conducive towards our common goals. The technical and economic problems in the development and utilization of natural gas have been defined and discussed; and recommended action plans and programs in areas of Thailand-United States interest have been formulated. This achievement constitutes a sound and comprehensive basis for the development of natural gas utilization in Thailand and augurs well for Thailand-United States business relationship and cooperation in the future.

I trust that you are fairly familiar with Thailand’s energy picture. With the successful completion of the first phase of the Natural Gas Development Project in 1981, Thailand moved into the second phase which aims at increasing gas production. Significant projects presently being implemented include construction of a Gas Separation Plant, promotion of LPG utilization in the rural areas as well as in transportation and promotion of ethylene cracking for future petrochemical industry. The petrochemical industry is the major part of the Eastern Seaboard Development. Major petrochemical industries under immediate development in Thailand are for the production of olefins and their derivatives and fertilizers. Both complex are under planning and expect to be in operation by 1988.
As we enter the new era of vigorous industrial development, we heartily welcome and appreciate the United States close relationship and cooperation at both the government and business levels. We Thais greatly value our long-lasting friendship and warm relationship with the United States. In the future, we look forward to closer cooperation in the spirit of partnership and interdependence for our mutual benefit. Our investment door is always open to the private sector, not only with attractive incentives and good track of record on growth, but also with a pledge of solid cooperation.

In the light of what you have achieved from this Symposium, I take great pleasure indeed in extending my warm felicitations to the Embassy of the United States of America and the Petroleum Authority of Thailand for putting in a stupendous effort in organizing this Symposium and bringing together some of the finest think-tanks in the industry to present their viewpoints and the result of their in-depth studies on natural gas utilization, its relevant technical and economic problems and its futuristic potential development.

My highest acknowledgement and praise go also to all the speakers and participants here to whom I would like to record my deep appreciation and thanks for the invaluable contributions you have made towards the success of the Symposium. I have cause to express deep satisfaction because you have really given your best towards making this Symposium a success in realistic terms.

It gives me even greater pleasure to note the cordial and friendly atmosphere prevailing here which is a happy reflection of the fruitful and constructive exchanges of views you have had during the past few days.

I wish to express the same sentiment to the members of the Secretariat and others, without whose hard work and selfless devotion to duty, the smooth running of the Symposium would not have been possible.

In other words, all have been done in perfect harmony. I therefore, thank each of you most heartily for your spirit, hard work and personal sacrifices.
Ladies and Gentlemen, having enjoyed this opportunity to meet with you, I would like to close here with an expression of hope that the United States and Thailand will long be partners for future progress and prosperity in this part of the world.

Thank you.